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New Allocation of Roles and Business Segments of Established and new Participants in the Energy Sector Currently and Within a Future Electricity Market Design

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Final Report

New Allocation of Roles and Business Segments of Established and new Participants in the Energy Sector Currently and Within a Future Electricity Market Design (Topic 3)

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Abbreviations and Units

Abbreviations

AbLaV	Verordnung zu abschaltbaren Lasten (Ordinance on detachable loads)
ARegV	Anreizregulierungsverordnung (Ordinance on incentive regulation of energy supply grids)
AtG	Atomgesetz (nuclear energy law)
BDEW	Bundesverband der Energie- und Wasserwirtschaft (Federal Association of Energy and Water Business)
BMWi	Bundesministerium für Wirtschaft und Energie (Federal Ministry for Economic Affairs and Energy)
BMUB	Bundesministerium für Umwelt, Naturschutz, Bau und Reaktorsicherheit (Federal Ministry for the Environment, Nature Conservation, Construction and Nuclear Safety)
BNE	Bundesverband Neue Energiewirtschaft (Association of Energy Market Innovators)
BKart	Bundeskartellamt (Federal Carte Office)
BNetzA	Bundesnetzagentur (Federal Network Agency)
BSI	Bundesanstalt für Sicherheit in der Informationstechnik (Federal Office for Information Security)
CHP	Combined heat and power
DSM	Demand-side management
DSO	Distribution System Operator
EEG	Erneuerbare-Energien-Gesetz (Renewable Energy Sources Act)
EEX	European Energy Exchange
EGC	Electricity and Gas Market Surveillance Commission
ENTSO-E	European Network of Transmission System Operators for Electricity
EnWG	Energiewirtschaftsgesetz (Law on energy business)
EOM	Energy-only Market
EPCO	Electric Power Company
ESCJ	Electric Power System Council

EU ETS	European Emissions Trading Scheme
FC	Frequency Converter
FIT	Feed-in Tariff
G Component	Generation Component
GEU	General Electric Utility
ICT	Information and Communication Technology
IoT	Internet of Things
IPP	Independent Power Producer
JAPC	Japan Atomic Power Company
JEPX	Japan Electric Power Exchange NordPool
KAV	Konzessionsabgabenverordnung (Ordinance on concession fees)
LCOE	Levelized cost of energy
METI	Ministry of Economy, Trade and Industry
MsbG	Messstellenbetriebsgesetz (law on the operation of meters)
NEP	Netzentwicklungsplan (Network Development Plan)
NetzResV	Netzreserveverordnung (Ordinance on the network reserve)
NPO	Non-Profit Organization
OCCTO	Organization for Cross-reginal Coordination of Transmission Operators
PPS	Power Producer and Supplier
PPA	Purchasing Power Agreement
PV	Photovoltaic
RE, RES	Renewable Energy/ies, Renewable Energy Sources
SINTEG	Schaufenster intelligente Energie – Digitale Agenda für die Energiewende (Smart Energy Showcases – Digital Agenda for the Energy Transition)
StromNEV	Stromnetzentgeltverordnung (Ordinance on electricity network fees)
StromNZV	Stromnetzzugangsverordnung (Ordinance on access to electricity networks)
StromStG	Stromsteuergesetz (Law on electricity taxation)

TEPCO	Tokyo Electric Power Company
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
VKU	Verband kommunaler Unternehmen (Association of municipal Businesses)
VPP	Virtual Power Plant
(V)RE, RES	(Variable) Renewable Energy Sources

Units

kW, kWh	kilowatt, kilowatthours
MW, MWh, MWp	Megawatt, Megawatthours, Megawatt peak
GW, GWh	Gigawatt, Gigawatthours
TWh	Terawatt, Terawatthours

1 Introduction, Summary and Recommendations

1.1 Introduction

This report is part of a larger research effort of the German Japanese Energy Transition Council (GJETC) and represents „strategic topic 3" out of 4 strategic research topics. Out of the different comparative reports between Japan and Germany it deals with the energy system and energy market design dimension of the energy transition and what the implications for the involved stakeholders (old and new) are.

For the success of an energy transition not only technological preconditions, but also a societal transformation (also shown by institutional adaptation and innovation) is necessary. Important drivers of a long-run transition of the energy system are subnational entities (regions or municipalities), which, like in Germany, often follow more ambitious targets compared to national institutions and could function as lighthouses. The opportunities and challenges for the development of sub-nationalities, but also established energy-companies depend heavily on the national frame conditions especially on the current and future electricity market design. Therefore, it is crucial to discuss the role of established and new participants in the energy sector within the context of the specific and different national framework-conditions (particularly the electricity market design and the corresponding legislation and regulation) in Japan and Germany. Subnational entities like prefectures, states, and municipalities, in particular cities (including municipal services) can possibly gain economic benefits from energy transition strategies. With revenues, especially from renewable energy power generation and energy services, new scopes of action can be unlocked, and added value can be generated within the constituency. Furthermore, local administrations have to deal with the consequences of climate-change in the long-run, which is an additional factor for motivation. A further pillar are citizens' initiatives and energy cooperatives, which have been proven to be very important for the implementation of renewable energies in Germany, and hence, for the energy transition. In Japan, too, increasing activities in this respect can be observed. On the other hand, the established participants in the energy sector will also have to develop new business models and areas and be enabled to participate in the energy transition on a level playing field. Especially, national development schemes and targets for renewables are important framework conditions for the development of new decentralized business fields.

In this environment, the Japan Electric Power Information Centre (JEPIC) conducted the analysis on the Japanese energy system and the IZES gGmbH (Institute for future energy and material flow analysis) did so on the German energy system (both chapters 2-7). Afterwards both partners commented on the respective others' energy systems and energy transition strategies (chapter 8) and finally drew common conclusions (chapter 9). Table 1 compares the main facts between the Japanese and German energy systems and energy transitions. In conjunction with that a chapter-by-chapter summary of the report is given. The table is reproduced in chapter 8 and builds the basis for the mutual comments.

Currencies have been converted from yen to euros and vice versa to give both audiences a better possibility for comparison. Historical annual exchange rates of the respective years have been used.

1.2 Summary

Table 1 Comparison of facts on the energy system between Japan and Germany

Germany	Japan
Chapter 2	
Liberalization	
Energy markets are fully liberalized; guaranteed network access and transparent network pricing without possibility to cross-subsidize is key; switching trends have increased over the years but are lower in households than in businesses, nevertheless concentration measures are low	liberalization is only now gaining thrust; incumbents still have a dominant position; switching rates are low, esp. in low voltage segment (picture somewhat similar to early stages of liberalization in Germany)
Energy transition policy / long-term plan	
Long-term strategy reaching to 2050; energy transition based on VRE and energy efficiency; long-term goals for GHG reduction, RE-shares and efficiency; RE have reached system relevance	Basic energy plan reaching to 2030 (under revision); future role of nuclear power and RES not yet clear; voluntary GHG goals; RE-shares comparatively low but significant rise in PV-capacities since 2012
Structure of generation systems	
Constant buildup of RES-capacities since 1990's; compensate for start of controlled nuclear phase-out; high shares of coal	Sudden drop of nuclear production due to Fukushima-accident; equal increase from fossil fuels (mainly nat. gas), low RE-capacities
Chapter 3	
Efficient dispatch – Energy market setup	
Exchange model – free trade regardless of network congestions ('illusion of copper plate')	Incumbent's self-supply based on the merit-order still dominating the market; Regulatory instruments to activate the market being introduced.
Comparatively high product variety and trade volumes as well as more players at market (longer history of liberalization)	Market not yet developed; comparatively low product variety and trade volumes
Part of EU market integration effort; but common market zone with Austria will be split in 2018	Regular market splits along former monopoly areas (too low transmission / converter capacities)
Clean dispatch (conventional): CO_2-intensity	
More or less constant decrease between 1990-2015 from 760 to 540 g/kWh	1990-1998 sinking; 1998-2007 rising beyond original value; 2008-2010 steep fall (to around '98 value); 2011-2013 steep rise (all time high) 2013-2015 sinking again but still higher than 1990
Clean dispatch (conventional): instruments changing merit order	
EU ETS: raises marginal costs according to CO_2-intensity (GER as part of EU system)	Depending principally on voluntary efforts by utilities
FIT: introduces new capacities at "far left" of merit-order	FIT: introduces new capacity at "far left" of merit-order

CHP: fix premium per kWh from CHP lowers marginal costs	
Chapter 4	
Financing firm capacities	
Focus on increasing system's and market's flexibility to serve VRE (firm capacity as one option within a menu of flexibility options) No introduction of capacity market due to focus on flexibility; instead creation of level playing field for flexibility options through sufficient flexible energy-only market (make them economically worthwhile); various instruments for flexibility	Focus on baseload: open access of existing baseload to newcomers, new incentives for new baseload capacities Various instruments for baseload incl. capacity market as of 2020; obligation for retailers to secure all energy and submit ten-year demand and supply plan annually
Financing variable capacities	
1990: first version of FIT, adapted ever since (capacity shares 2015 of PV 19% and wind 20%, significant biomass); current switch to auctioning hotly debated as it is feared that it may disadvantage small stakeholders	2012: FIT (before: portfolio standard, net metering) 2012-2015: significant increase of PV (capacity share 2015: 7%) but low wind and other REs; now switching to auctioning for the large-scale PV
Management of networks	
Part of European effort to integrate electricity system (see chapter 3) and increase interconnector capacity	Relatively weak network, interconnector management important, therefore included in market design (see chapter 3)
Priority access for RE as part of FIT	No real priority access for RE; concept of "connectable amount"; amount has dropped to zero in some areas
Despite difference to Japan (Germany is hub within Europe): opportunity to increase efficiency by increasing interconnections between countries	Despite difference to Germany (Japan is an island): opportunity to increase efficiency by increasing interconnections within the country
Chapter 5	
Business models: generation	
In General: IPP; with regard to energy transition: RE-investors and/or –operators	Before 2011 some specialized power producers supplied specific regions but with low share; after 2011 market entries increased somewhat but concentration stays high due to integration measures of incumbents (see above)
Business models: wholesale	
Rise of green electricity products since direct market sales are mandatory Direct marketers act as agents for RE-capacity owners who do not market themselves Aggregators bundle flexible loads (DSM) and focus on ancillary services	Various measures including Gross Bidding being introduced to activate the wholesale market
Business models: retail / supply	
Green electricity products used for product differentiation (guarantee of origin since 2017)	A number of new market entries, business models get more diverse; incumbents still own 90% market share
sector coupling: number of new likely business models (after reform of charges and levies); first incentives in latest FIT-reform (usage of excess electricity in congested areas); municipal utilities seem well-positioned going along with a trend of remunicipalization	

Prosumerism: new in private households, increasing also for quarters; raises issues for grid planning and finance Specialized industries: energy service companies (ESCOs, energy efficiency) once relevant markets are established Non-specialized industries: new possibilities to lower electricity purchase costs as flexibility and efficiency receive remunerations	
Business models: networks	
4 TSO and 875 DSO; incentive regulation scheme; grid connections with EU-neighbors & part of EU-integration effort, incentive regulation, priority access for RES	10 network (T&D) operators and one privately operated T line dedicated to collect wind energy; Regulation based on cost-of-service; long-term fixed power sources (nuclear, etc.) prioritized; access by first-come first-serve basis and inflexible connectable amount
Chapter 6	
General distributional mechanisms	
Efficient dispatch & market price: costs and risks are a matter of market outcome (influenced, in turn, by regulation)	Efficient dispatch: risks may change due to liberalization for incumbents and IPP alike, raising financing costs
Efficient dispatch & charges and levies: almost all other cost (EU ETS, CHP, FIT) are levied on electricity consumption and large consumers are exempt	
Clean dispatch: as above, costs levied on electricity consumption and large industries are exempt	Clean dispatch: Rising FIT levy due to rising RE-capacities: costs are levied on electricity consumption and large industries are exempt
Specific distributional mechanisms	
Network charges & electricity tax: same principle as general mechanism – levy on electricity consumption and exempt large consumers	Network charges & electricity tax: Focus on challenges of future network pricing under changing conditions; smart grid enable new financing models
Large consumers buy electricity directly at wholesale market, benefit from low prices	
Final customer prices (price components)	
Reiterates points of previous sections: private households and non-energy-intensive business are levied, energy-intensive business are not	Three block rate system for regulated rates: rising unit prices as consumption increases to enhance energy savings
Chapter 7	
New establishment of business models (subsumed under chapter 5)	Business models getting more diverse as diverse companies entering the market (see also chapter 5); Some new municipal utilities have been established but face particular challenges due to centralized nature;
Value creation from RE: more evenly distributed than from fossil fuels (but also depends on tax system and firm structure) Job creation from RE: more evenly distributed than from fossil fuels Resource efficiency in cities: High local level of value creation, in particular for efficiency investments (refurbishments of buildings) Cities as agglomerations of infrastructures that need to be modernized in the course of transi-	

tion; smarter infrastructures needed for better intra- and cross-sectoral coordination (smart grids and technologies)
Due to scale of task ('man-on-the-moon-project') it goes beyond mere restructuring; participation is vital and municipal utilities are key

Source: own depiction

In **chapter 2** the report begins by analyzing where both countries stand in terms of energy market liberalization and energy transition policies. It shows that the starting points of both countries are quite different in terms of energy systems and institutional settings. The first and most obvious difference is the fact that Japan is an island (or, more precisely, consists of a number of islands) and that Germany is located in the middle of Europe. The latter leads to a hub situation for the energy system due to the connections with its neighbors and institutionally it is embedded within a European regulatory framework.

On liberalization, Germany's energy markets are fully liberalized whereas in Japan incumbents still have a dominant position and liberalization is only now gaining thrust. That is, in Japan most capacities (in particular baseload) are still owned by the incumbents, concentration measures are high and switching rates of consumers are low. The picture is somewhat similar to the early stages of liberalization in Germany. Here, incumbents' market concentration is steadily decreasing on the wholesale market due to the nuclear phase out and the steady growth of renewable capacities. Further, the number of participants and financial volumes has also been steadily increasing. On retail markets, too, numbers get more favorably over the years. The history of the German liberalization has shown, however, that guaranteed network access and transparent pricing regimes of network use without possibilities for incumbents to cross-subsidize in combination with an independent regulatory agency is key. The negotiated grid access (basically a self-regulation mechanism), as it was first introduced, did not succeed to level the playing field of independent power producers vis-à-vis incumbents.

On energy transition policies, Japan's current long-term energy outlook includes goals for nuclear and renewable energies for 2030. The basic energy plan is now under revision and the future role of nuclear power is not yet clear. Nuclear power has always played a central role in Japan but is now under revision after the Fukushima accident. Also, shares of renewable energies are comparatively low in Japan but due to new policies growth rates in photovoltaic capacities have risen significantly since 2012. Germany has been continuously building up renewable energy capacities (with prior development of the technologies) to a degree that these are now reaching system relevance. Together with the need to decarbonize the energy system and to phase out nuclear energy, this has led to the development of a long-term strategy for an energy transition based on variable renewable energies and energy efficiency until 2050.

Chapter 3 analyzes the interrelations between the energy transition and dispatch of capacities. The section on efficient dispatch shows the basic setup of the Japanese and German energy exchanges, their sizes and stage of development, market segments and specific characteristics. Here, too the early stage of Japanese liberalization is mirrored in the market activities: Trade volumes at the energy exchange are still comparatively low. Further, Japan conducts regular market splits along the lines of the former monopoly areas because interregional transmission / converter capacities are relatively low, leading to different pricing zones. Here, the information on generation cost on the Japanese energy system is also supplied denoting nuclear as the cheapest source of energy. This has sparked some discussions among the project partners on the insecurities of long term price estimates. Due to the longer history of the German liberalization the volumes traded are higher and products are more differentiated, in particular with regard to the short term. This enables the participation of new players, reduces the costs of system services and eases the integration of variable renewable energies. Germany has deliberately chosen an exchange model at that time that abstracts from network restrictions ('illusion of the copper plate') in order to enhance competition. Nevertheless, network congestion and curtailment of renewable energies is an issue in Germany and the common market zone with Austria will be split in 2018.

The section on clean dispatch briefly sums up i) the CO_2-intensity development in the conventional segment and ii) how the different energy-transition-related instruments affect dispatch decisions. In terms of CO_2-intensity Japans numbers have been roughly sinking between 1990 and 1998 and where then rising again until 2007. Then – with the beginning of the first Kyoto commitment period – they took a steep fall until 2010 and then – after the Fukushima accident – emission intensity started to rise very steeply again until 2013 before it started to fall again. In Germany, intensity of CO_2-emissions basically fell between 1990 and 2015. In terms of instruments, the European emissions trading scheme, the feed-in tariff and a fix premium per kWh produced from combined heat and power (CHP) capacities can be named to directly influence the dispatch decisions in Germany. In Japan, there is a feed-in tariff as well. Emissions trade changes the marginal costs of all conventional capacities by including carbon costs according to carbon intensity. It therefore changes the merit-order provided prices are sufficient. The feed-in tariff with its priority feed-in includes capacities at the beginning of the merit-order thereby reducing demand from all remaining capacities. The CHP-premium reduces variable costs shifting those capacities before comparable ones.

Chapter 4 analyzes the interrelations between the energy transition and financing capacities. In the section on financing firm or dispatchable capacities, Japan has a clear focus on two aspects: opening access for newcomers to existing baseload capacities and putting in place new incentives for new baseload capacities. Further, all retailers are obliged to secure energy for the next ten years which sets the same incentives as a capacity mechanism. Germany takes a different approach. As it has opted for a VRE-based system, its main focus is on increasing the system's and the market's flexibility. It is therefore putting in place a market design where different flexibility options may compete on a level playing field. Here, firm capacity is one option within a menu of flexibility options. That is, firm capacities, too, need to be flexible. This is not always the case with baseload capacities. The idea is that increased flexibility is necessary from a systemic perspective to integrate VRE and that a sufficient flexible wholesale market that mirrors this flexibility avoids the missing money problem. Therefore, and out of concerns that capacity markets may conserve the current structure in the conventional segment, Germany decided against capacity markets and opted for a wide range of measures to enhance flexibility.

In the section on variable capacities, Japan had introduced a portfolio standard and a net metering system before it switch to a FIT in 2012. This has led to a significant increase in growth rates of PV-capacity between 2012 and 2015 leading to an overall share of generation capacity 7%. However, wind capacities have not increased due to a number of reasons. Japan is now switching to auctions due to rising cost. In Germany, the first version of the feed-in tariff has been introduced in 1990 and has been adapted ever since and the latest version has entered into force at the beginning of 2017. Apart from raising the capacity shares of PV to 19% and of wind to 20% (as well as significant biomass capacities) the German energy transition has also always been a story of new stakeholders entering the energy system why it is sometimes referred to as a collective project (*Gemeinschaftswerk*) or as 'democratizing' energy. That is, private individuals get together in cooperatives to manage renewable energy capacities and the FIT served as an enabler as it provided an easy business model. Therefore, the current switch to auctioning is a hotly debated issue as it makes the business model more complicated and the concern is that cooperatives of private individuals may not be able any more to follow suit. However, it is too early for a final judgement.

The section about networks sums up the planning processes and specific issues in Japan and Germany. In Japan networks are relatively weak therefore management of interconnectors is an important issue – this is the reason why the market design follows the fragmentation as it was noted above. For the same reason new capacities – in particular renewable ones – are restricted by the concept of connectable amount. The connectable amount is determined by a renewable energy sub-committee conducted by METI. That is, in the end grid extension is a management decision of the grid operator and therefore there is no privileged access for renewables like in Germany. Currently, connectable amount has dropped to zero in some areas. In Germany, there are transmission lines with various European neighbors. Nevertheless, capacities are scarce and need to be managed. Germany is part of a European effort to integrate the national electricity markets and to increase transmission capacities (European target model). Despite the obvious differences between Japan and Germany (Island vs. central location within Europe) there is also a similarity. As Europe tries to increase the efficiency of its market by increasing the interconnections *between* the member states Japan tries to do so *within* the country.

Chapter 5 analyzes the business models and players in the energy sector that have emerged or are likely to emerge due to the energy transition. This is done along the value chain of production, transmission, distribution/supply and consumption.

In Japan – despite first reforms dating back to 1995 – real changes have been triggered by the Fukushima accident in 2011 and various players are now entering the market after key decisions have been made like legal unbundling and full retail competition. Therefore, it can be distinguished between business models before and after 2011. Before 2011 the ten incumbents had a dominant position. Apart from these there where a number of specialized power producers though, supplying specific regions but only with small shares. Therefore, trade activities where (and still are) few, as mentioned before. The typical investor group was banks as incumbents relied on long-term debts. As electricity market reform is beginning to show some effect some more business models have occurred after 2011. However, despite unbundling until 2020 a number of incumbents aim at keeping generation and retail in one company and have networks as subsidiaries. Concentration is still high as – despite a number of new producers – the overwhelming share of capacity is owned by the few incumbents. As a new business model for transmission, one out of two transmission operators is privately operated by wind developers and financial institutions, with the specific purpose to collect wind energy. A number of retail or supply companies have entered the market – despite an incumbents' market share of 90% – and business models get more diverse with increasing competition in particular in metropolitan areas. Switching rates are still low, however, and – like in Germany – for private customers they are lower than for business. In terms of investments, business models may change as risk profiles change with liberalization.

In Germany the numbers of players and business models have increased significantly. However, a number of these have also emerged simply due to liberalization. Here, it shows that liberalization is a prerequisite for energy transition as it provides a framework where participants can develop new business models.

In generation, apart from the integrated and municipal utilities that existed before a number of new players came in. In general, these are independent power producers and with regard to the energy transition these are investors in and operators of renewable energy capacities. That is, sometimes investors and operators are the same entities, sometimes they are different.

A wholesale market was introduced with liberalization, leading to trading businesses and the establishment of electricity exchanges that were then also used for "green" electricity products. In Germany, the significance of “green” electricity products rises since the German FIT-system has now changed to mandatory direct market supply. That is, instead of the TSO selling the electricity on the spot market for the renewable capacity owners, these now have to do that themselves – or through an agent. Here, direct marketers step in who bundle renewable electricity (using bilateral contracts with the respective capacity owners) and sell it at the wholesale market. Various products are still being developed. Aggregators are another new category of players (actually a sub-category of direct marketers). They aggregate or bundle flexible loads and focus on ancillary services. That is, they are active in demand side management and currently focus on control reserve markets. In general, ancillary services have existed before. But with the advent of liberalization they became a market activity and with the energy transition their significance, too, rises due to rising flexibility needs, leading to the participation of new players (industrial capacities, CHP capacities, renewable capacities).

In retail or supply, “green” power products may be used for product differentiation and raising the margin. As of 2017 the German FIT has introduced a guarantee of origin enabling to market not only “green” but also regional electricity products. Other business models are conceivable but require regulatory changes: retailers could be made responsible for the integration of renewable energies or they could be obliged to achieve energy efficiency targets, leading to the development of a whole new range of products. Sector coupling will gain increasing importance and a number of business models will evolve around it. So far, they barely work since the system of charges and levies provides disincentives. First incentives, however, are given in the latest version of the FIT to find usage for excess electricity in congested areas. Furthermore, it is not clear yet whether it will be established or new players. Basically, all players active in more than one sector qualify, putting smaller municipal utilities with their (not unbundled) DSOs in a pole position. They have access to electricity and district heating networks and very often they also have to manage public transport, public pools etc. Still, there should not be a trade-off with the issue of free access to the network. Further, private households may also be active in sector coupling as they use heat, electricity and mobility. The fact that municipal utilities seem well positioned also goes along with a trend of establishing new municipal utilities in recent year in Germany. Some consider this a trend towards remunicipalization as it would fit well with the more decentralized nature of the energy transition.

Prosumerism (or auto production, own consumption) is a new business model with regard to the private sphere (in industry it has existed for a long time). It is due to i) the surprisingly quick decrease in PV-system costs and ii) saving of grid charges when not consuming electricity from the grid, both leading to own electricity being cheaper than the one from the grid (grid parity). With battery prices also decreasing, the share of own consumption will rise further. It is therefore a (future) business model for private households as well as for quarters. However, it implies a number of issues for grid planning and grid finance.

Industrial business models maybe distinguished between non-specialized and specialized industry. The first group does not have its core business with the energy transition but simply uses electricity as an input factor. Not being a specific feature of energy transition, they have (or should have) an interest in energy efficiency of their production processes to the extent electricity prices are rising. To the extent flexibility receives a market value under the energy transition, however, they may find new business models as provider of system services, e.g. as a business partner of aggregators. So far, however, there have been a number of barriers to implementation. The second group may be specialized on energy transition but with a focus on energy efficiency like energy service companies (ESCOs), once markets for energy services are established. These could then provide services like contracting for heating, cooling and electricity supply.

Cross-cutting issues are the liberalization of metering and digitization. Smart meter gateway administrators are responsible for secure operation of smart meter systems. This is the basis for all business models evolving around smart meter / smart home applications.

Chapter 6 analyzes the distribution of costs and risks of general and specific distributional mechanisms. The section on general mechanisms deals with costs and risks of efficient and clean dispatch. In Japan efficient dispatch focuses on changing risk profiles due to liberalization – for IPP and incumbents alike – that may lead to higher risks of investments and, in turn, to increasing costs of finance. In terms of clean dispatch rising costs of the feed-in tariff system are noted. Apart from high growth rates of PV-capacities these are also partly due to exemptions for energy intensive industries.

In Germany the section on efficient dispatch shows that the costs and risks of conventional capacities are a matter of market outcome and wholesale prices have so far been sinking – to the disadvantage of the capacity owner (supplier) and the benefit of retailers and large consumers on the wholesale market. Naturally, the market outcome is also determined by the regulatory framework. All other costs of the conventional system (ancillary services) as well as of the clean dispatch (EU ETS, CHP) and clean finance (FIT) are basically distributed by the same principal: cost are levied on electricity consumption and large consumers are exempt on the grounds of international competitiveness concerns, using some kind of indicator. Usually the larger the consumer the larger the exception gets, leading to an uneven distribution of costs. An exception is the cost of control reserve where deviations of large consumers are allocated directly.

In the section on specific mechanism – network charges, electricity tax – in Japan the challenges of future network pricing under changing conditions are pointed out. In particular, prosumerism and reverse electricity flows that go along with VRE-capacities. However, new financing models that are enabled by smart grid solutions are also pointed out. For Germany the cost distribution of network charges and electricity tax follows the same principles as for the general ones since the costs are levied on electricity prices and, again, large consumers are exempt. Further, it needs to be mentioned as a general mechanism that very large consumers act as customers on the wholesale market themselves (not via a retailer) and are therefore able to benefit from the low wholesale prices in Germany further amplifying the uneven distribution. The challenges of grid finance have been mentioned under the business models. Finally, the section on final customer prices analyzes the price components for different customer groups. In Japan the rate system points to a three block rate system with rising unit prices as consumption increases in order to enhance energy savings. Furthermore, cost estimates are shown that include low costs for the “nuclear backend” which has sparked discussions between the project partners. It also shows the amount and kind of tax that utilities pay. For Germany, analysis of price components reiterates the point made before on the unequal distribution since households and non-energy intensive industries pay significantly higher electricity prices due to the levies. Furthermore, charges and levies have meanwhile reached around 40% of the household electricity price.

Chapter 7 shows the development of sub-national entities and resource efficiency in cities. In Japan, some new public utilities have been established in recent years. The two most important motives are securing energy in emergency and tackling climate change but also reducing energy costs. However, due to the centralized structures in Japan municipal energy companies face particular challenges.

In Germany, life cycle assessments have shown that value creation from renewable energies is more evenly distributed than from fossil fuels. It depends, however, on the tax system and where companies constructing, building and operating renewable capacities have their headquarters, i.e. where they pay taxes. Nevertheless job creation is more evenly distributed in any case. In terms of resource efficiency in cities the same life-cycle analyses have been made for energy efficiency investments, in particular retrofits of buildings. They have been yielding the same results, i.e. there is a high level of local value creation so that cities can benefit from the energy transition. Energy efficiency investments in efficient household appliance are also important. Industrial efficiency and ESCOs have been mentioned before as well as green and regional electricity products and sector coupling. Taken together, cities represent agglomerations of infrastructures and these need to be modernized to make them suitable for the energy transition. With regard to issues like decentralization, smart grids, district heating and sector coupling this becomes particularly relevant for the upcoming task of system integration of VRE. Therefore, cities and municipalities are the key for the next stage of the energy transition. Because of this and because of the scale of the task (‘man-on-the-moon-project’, ‘generation-project’), however, it has been noted that it goes beyond a mere restructuring effort and that participation is vital in order to ensure acceptance with financial participation being one means.

In **chapter 8** both project partners commented on each other’s analysis and responded to each others’ comments. Different starting points in terms of geography but also in terms of timing of liberalization vis-à-vis energy transition and relevant energy technology developments where pointed out. The German partner notes that whereas Germany is already liberalized it now needs to undergo a second round of market design changes to accommodate the energy transition. Japan has the opportunity to do both at once. Further, competitive renewable energy technologies are nowadays available easing the strategic choice. Different views exist on the question of whether capacity markets are necessary or not. Japan plans to introduce capacity and baseload markets whereas Germany disbands the concepts altogether as it bases its future energy system on VRE (not meaning that no firm capacity will be necessary but with high flexibility requirements). Here, the German analysis notes that the future role of baseload should be determined first before introducing new instruments, in particular since baseload and variable capacities will be not compatible in the long run. This leads to the most contentious point in the mutual comments which is the future role of nuclear energy in an energy transition scenario. Apart from incompatibility there are open question in terms of cost assumptions and who bears those costs and risks in liberalized markets. Other contentious issues include the amount of cross-border electricity flows when basing an energy system on VRE. Other remarks refer to renewable energies reducing import dependency and the strategic role of electricity networks. Here, the concept of connectable amount was critically assessed from the German partner and it appears as an important bottleneck where not only technical but also institutional changes seem necessary. On the technical side, however, a given amount of VRE-capacity is easier to integrate when the technology portfolio is more balanced. In a broader view, the necessity to go beyond just electricity was mentioned.

In **chapter 9**, finally, common conclusions were drawn in a commonly agreed text. The different stages of liberalization of the two countries are highlighted as well as the commitment to the Paris agreement – one of the main driving forces of the energy transition. Furthermore, the need for a long term strategy is pointed out in order to avoid stranded investments. On the strategic role of electricity networks it is pointed out that both countries have options for increasing efficiency by increasing interconnections. One with its neighbors and one within the country. It is also mentioned that the views on nuclear energy are controversial. Germany follows its phase out and Japan is currently reconsidering the future role after it has been regarded as safe and clean for many years. Both countries have rising FIT-rates (on different levels though) as growth rates have been rising and industry exemptions have further contributed to the growth. In addition, Germany pays off technology development cost via this instrument. However, an energy transition based on renewable energies would be beneficial for both countries in terms of reduced import dependency as these represent “domestic” energies. This should be taken into account when discussing their costs and comparing them with other technologies. Both countries should make use of their domestic resource. Finally, in Germany, the energy transition always had the additional dimension of people organizing themselves why it was coined ‘collective effort’ (*Gemeinschaftswerk*) or ‘democratizing energy’. It shows that there was always another dimension to the issue of energy transition.

1.3 Recommendations

The following recommendations (incl. recommendations for further research) are derived from the report. These are reproduced in section 9.2.

- Both countries need to create a market design that translates the Paris agreement into their energy markets by setting incentives for the decarbonization of their energy systems. This, in turn, requires long-term guidance from the governments of both countries as the energy sectors involve long investment cycles and possibly associated sunk costs. The creation of this new market design partly results in different challenges for both countries though.
- A common challenge is the reduction of the use of fossil fuels: Despite the existence of its long-term plan, Germany needs to reduce the use of coal, in particular of lignite. Japan, too, needs to reduce the use of fossil fuels, in particular, if nuclear as an abatement option fails, Japan needs to reduce fossil fuel use by other measures. Both countries need to increase energy efficiency.
- Japan needs to establish a long-term plan. In particular, this plan needs to include clear guidance on the future role of nuclear energy in order to avoid (more) stranded investments. Japan also needs to increase its renewable energy share, in particular as most of those energy sources are also beneficial from an energy security point of view.
- Both countries need to make use of their renewable energy source endowments. Since there is a whole range of low-cost options available nowadays (incl. wind, PV and geothermal) both countries shall aim at a balanced distribution between technologies as this lowers integration costs.
- Reinforcement of the grid is of strategic importance for both countries and both countries do have the possibility to do so. Germany can further increase interconnections with its European neighbors. Japan needs to further increase interconnections within the country (between the former monopoly areas), i.e. of using the grid integration options that it has despite being an island country.

- Both countries need to set the framework for (more) sector coupling, i.e. for the inclusion of heat (and cold) and mobility. As a prerequisite, electricity grids need to be enhanced with new functionalities (smart grids) to enable the coordination between the sectors – technically and in terms of market incentives. That is, both countries need to carry the transition further and re-optimize the whole energy system including all infrastructures.
- Both countries should examine the current scheme to refinance the FIT-surcharge. New capacity additions are often low cost. That is, the rising surcharge is often due to old installations (i.e. due to technological learning) or due to exemptions to large industrial consumers. A number of ideas exist for alternative concepts.
- There is a necessity for further research on how to create sufficient incentives for the various flexibility options necessary to integrate variable renewable energies (VRE). There is more than one way to create sufficient incentives and implications may differ between Japan and Germany. Therefore, a thorough analysis is necessary of what incentives do the different market forms like an energy-only-market and various forms of capacity mechanisms create in the Japanese and German settings. Further research questions include their implications for efficiency, distribution and structural change towards a low-carbon economy.
- There is also necessity for research in instrument design for financing renewable energies. Even though there is a range of low cost technologies available, it is not always clear whether regional cost differences (i.e. between Japan and Germany) may be attributed to the circumstances or to differences in instrument design. Finding the regionally/nationally tailored instrument mix that is low cost, open to innovations without creating new lock-in effects is a research challenge that goes beyond the discussion of technology-neutral vs. technology-specific instruments.
- Further, there is a necessity for research on the integration of VRE and the integration cost as these are energy system specific.
- Furthermore, economic barriers to sector coupling need to be removed, leading to the research question of a new distribution of taxes and levies that accommodates various goals such as increasing flexibility (better transmissions of scarcity / surplus situation signals in the grid), emission reduction needs and distributional issues.
- Finally, another issue for research is the above-mentioned modification of a partly alternate refinanced FIT-system.

2 Foundations of electricity market design and prerequisites for new stakeholders: state of liberalization, unbundling and third-party access

2.1 Japan

2.1.1 The starting point

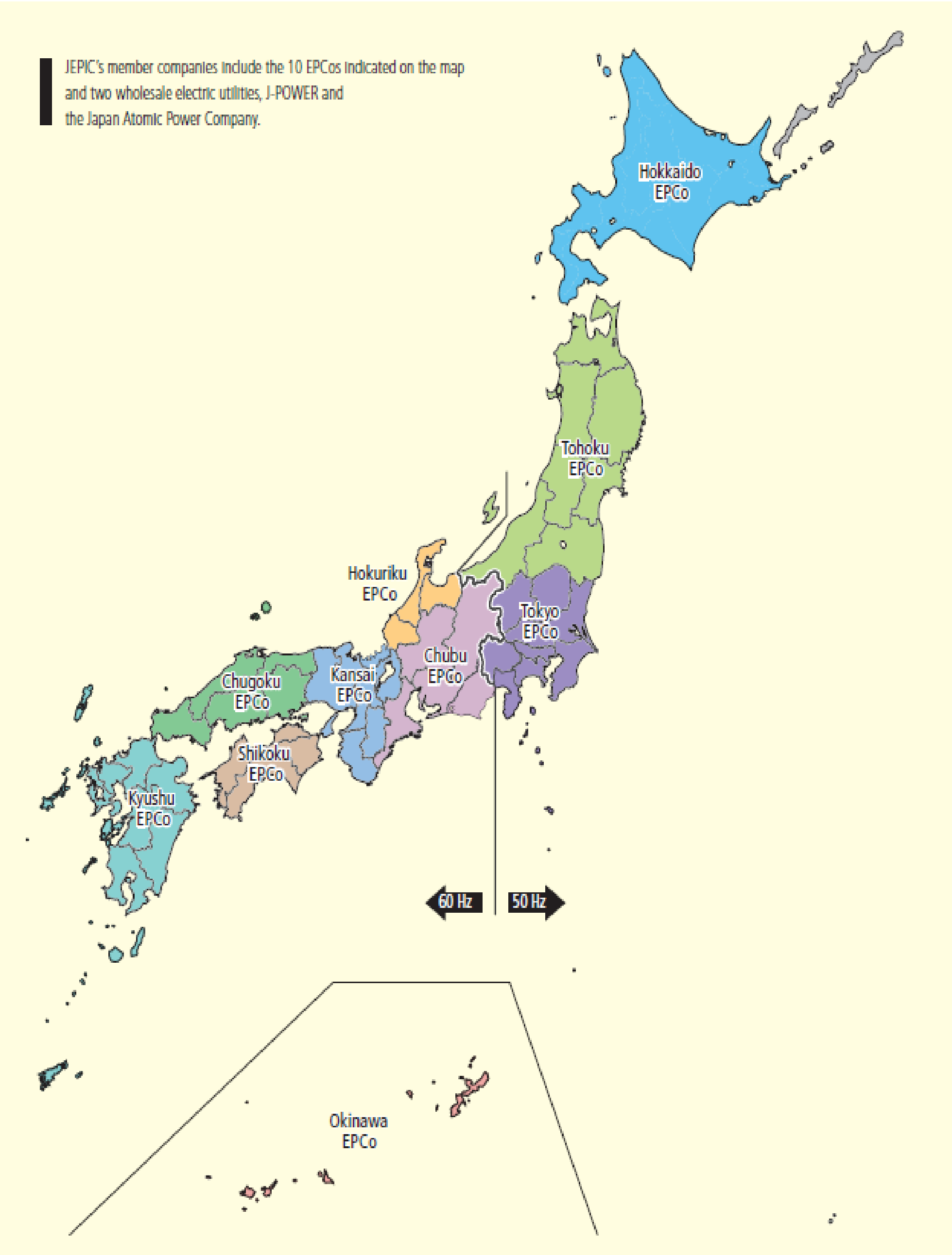
Japan's electric power industry came into being with the start of operations of the Tokyo Electric Light Company in 1886. Electric power companies were subsequently established in various parts of the country as demand for electricity grew with increasing industrialization and an economic boom that occurred during World War I. The number of electric power companies peaked at approximately 850 in 1932 (EPSREC 2012, p. 89). Excessive competition against the backdrop of the Great Depression etc. however, led to a series of mergers and acquisitions. As a result of this, the electric power companies were ultimately all integrated into five utilities. Those are Tokyo Electric Light Company, Daido EPCO, Toho EPCO, Ujigawa EPCO, and Nippon EPCO.

As Japan headed into World War II, the electric power companies were controlled by the government. After the Japan Electric Generation and Transmission Company was established in 1939, electricity generation and transmission was under centralized control, and electricity supply business was consolidated into nine separate blocks.

After World War II, the Japan Electric Generation and Transmission was dissolved in accordance with the Ordinance for the Reorganization of the Electricity Utilities Industry enacted in 1950 and the company's facilities were transferred to electricity supply companies in nine different regions around the country. The nine electricity supply companies to which the facilities were transferred subsequently became companies with regional monopolies based on an integrated electricity generation and transmission service system in which each individual company conducted integrated operation of every aspects of the business, from power generation to power transmission and distribution. This regime was confirmed by the Electricity Business Act enacted in 1964. The number of these electric power utilities increased to 10 with the establishment of Okinawa EPCO following the reversion of Okinawa to Japanese control in 1972 (JEPIC 1988).

Table 4 summarizes installed capacity and power generation of 10 electric utilities. These electric utilities were vertically integrated companies with well-defined supply territories (Figure 1). As we will see later, these companies will be legally unbundled in 2020. In addition to these privately owned electric power companies, there are large-scale wholesalers. J-Power and the Japan Atomic Power Company (JAPC) are major wholesale utilities. J-Power was established in 1952 by the government to develop initially large-scale hydro power and privatized later. JAPC specializing in nuclear power generation was established in 1957. JAPC is owned wholly by 9 electric utilities and J-Power. We will call 10 electric utilities, J-Power and JAPC “incumbents” in this paper.

Figure 1 Ten electric utilities and their areas



Source: (JEPIC, 2017)

In Japan, pillars of energy policy were three **E**s until the East Great Earthquake in 2011. That is **E**conomics, **E**nvironment and **E**nergy Security. Characterizing Japan's energy policy, security has been always a major concern in formulating energy policies because Japan is not endowed with natural resources. **S**afety has been added to the three pillars named above as a result of the Fukushima nuclear accident. These policy objectives are reflected in the Basic Energy Plan (METI 2014).

The Basic Act on Energy Policy stipulates that the government is to review the Basic Energy Plan at least once every three years. A review will be held in 2017, which will result in the formulation of the Fifth Basic Energy Plan. Discussion relating to the review are anticipated to begin from early 2017. The role of nuclear power and renewable energies will be again a contentious issue in the next Basic Energy Plan. Vision on these energy sources are critically called for in contemplating energy future in Japan.

It should be noted that the political system in Japan has been centralized unlike Germany or United States. Some local governments such as prefectural governments have their own energy policies. Yet the role of local governments in terms of formulating energy policies is generally very limited.

2.1.2 The process of electricity market liberalization in Japan

Many countries in the world started electricity restructuring in 1990's to improve sector performance. In line with this trend, Japan initiated the electricity market reform in the middle of 1990's. A major driver behind restructuring was Japan's high electricity prices comparing with those of other major industrial countries.

Electricity restructuring in Japan is evolutional (Table 2). The first set of reforms was implemented in 1995 with allowing independent power producers to enter in the generating sector. As deregulation of Japan's electric power industry continued, retail supply for customers receiving extra high-voltage (20 kV or above) was liberalized in 2000 following the 1995 liberalization of wholesale supply. The scope of deregulation was expanded further in stages thereafter: to high-voltage (6 kV) customers with contracted demand of 500 kW or above, in principle, in April 2004, and to all customers in the high-voltage category (those with contracted demand of 50 kW or above) in April 2005. Generally, large customers are much more elastic than small customers like residential customers to changes in prices. Yet, the market for large customers was inactive. It is noteworthy that competition between incumbents was almost none partly because of consumer's inertia and also utilities' inertia. It can be said for utilities' inertia that electric utilities hesitated to break the friendly relationship between them built historically by acquiring customers in other utilities' markets.

Table 2 Evolution of Electricity Restructuring in Japan

Stages	Outline
1st set of reforms (1995)	1. Introduction of a power procurement bidding system for general electric utilities. Permission for independent power producers (IPPs) to enter the wholesale business 2. Implementation of a system of “special electric utilities" authorized for retailing in designated service areas 3. Introduction of an incentive system to encourage general electric utilities to improve efficiency
2nd set of reforms (2000)	1. Liberalization of retailing for extra high-voltage customers 2. Change from an approval system to a notification system for rate adjustments
3rd set of reforms (2004)	1. Liberalization of retailing extended to high-voltage customers 2. Establishment of a neutral body for providing rules and monitoring aspects of the transmission and distribution of general electric utilities. 3. Introduction of a code of conduct for general electric utilities in transmission and supply 4. Development of nationwide wholesale markets
4th set of reforms (2008)	1. Activation of wholesale electricity exchange, and improvements in grid use competition conditions 2. Stable supply and environmental suitability (e.g., green energy trading)
Electricity system reform (2012 ~2020)	1. Expansion of cross-regional grid operation (establishment of OCCTO) 2. Full liberalization of retail market 3. Legal unbundling of transmission and distribution, and abolition of retail rate regulation

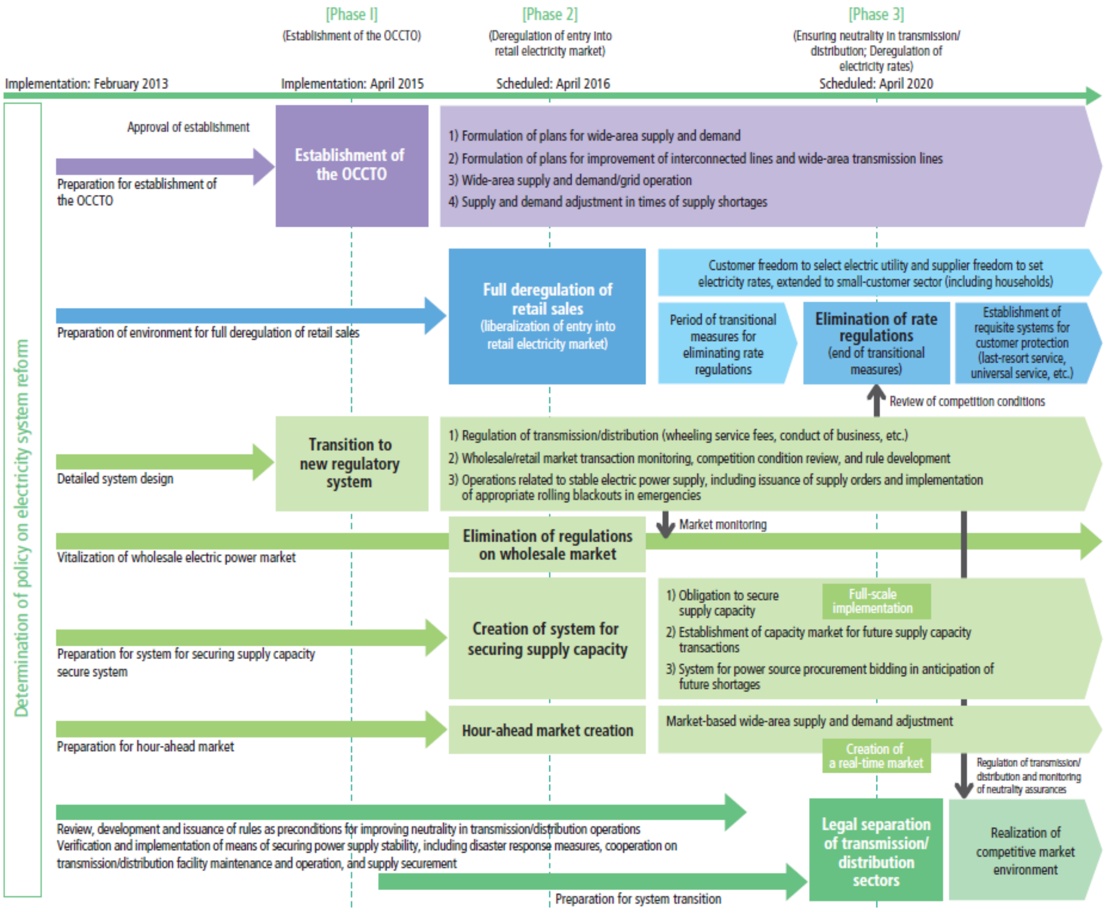
Note: Reforms were discussed or decided in the years indicated above, but not all were implemented that same year.

Source: JEPIC, 2017

METI engaged in deliberations concerning the pros and cons of expanding the scope of retail liberalization to include the household sector beginning in April 2007. These ended in a decision to reexamine the advisability of expanding the scope of retail electricity market liberalization after the five years. This was because the net benefit brought about by opening the small market was not expected at that time.

Power shortages and other issues caused by the 2011 Great East Japan Earthquake, however, prompted renewed discussion of the ideal configuration for the nation’s electric power system. Based on this discussion, a new entity called the Organization for Cross-regional Coordination of Transmission Operators (OCCTO) was established in April 2015, with the aim of enhancing the capacity to adjust supply and demand nationwide in both normal and emergency situations. In addition, from April 2016 full liberalization of the retail market including consumers utilizing less than 50 kW was implemented.

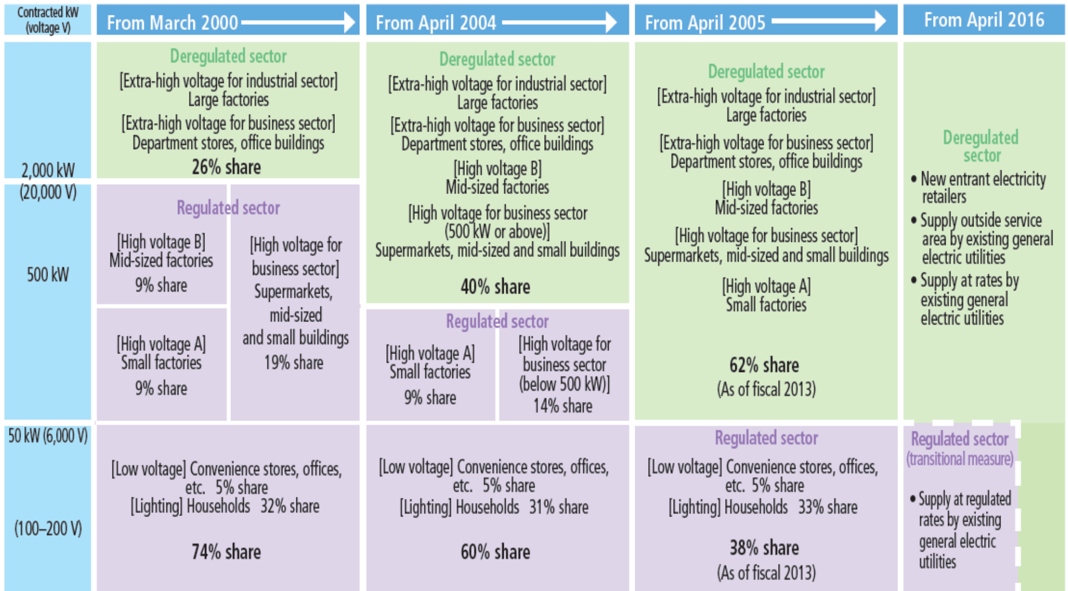
Figure 2 Roadmap of the System Reform toward 2020



Source: METI 2013, S. p. 45

The retail competition started with the liberalization of the large customer market in 2000. Since then, other markets have been gradually opened up to new participants. As Figure 3 shows, the market for the class of small customers which remained regulated has been liberalized in April 2016. Full liberalization of the retail market through the deregulation of Japan's low-voltage sector means that the approximately eight-trillion yen electricity market to which the former vertically integrated electric utilities supplied electricity under a monopolistic arrangement, has been opened up. With this change, the overall retail market with the including of the high-voltage sector which was already liberalized is now worth 18 trillion yen or 150 billion euros.

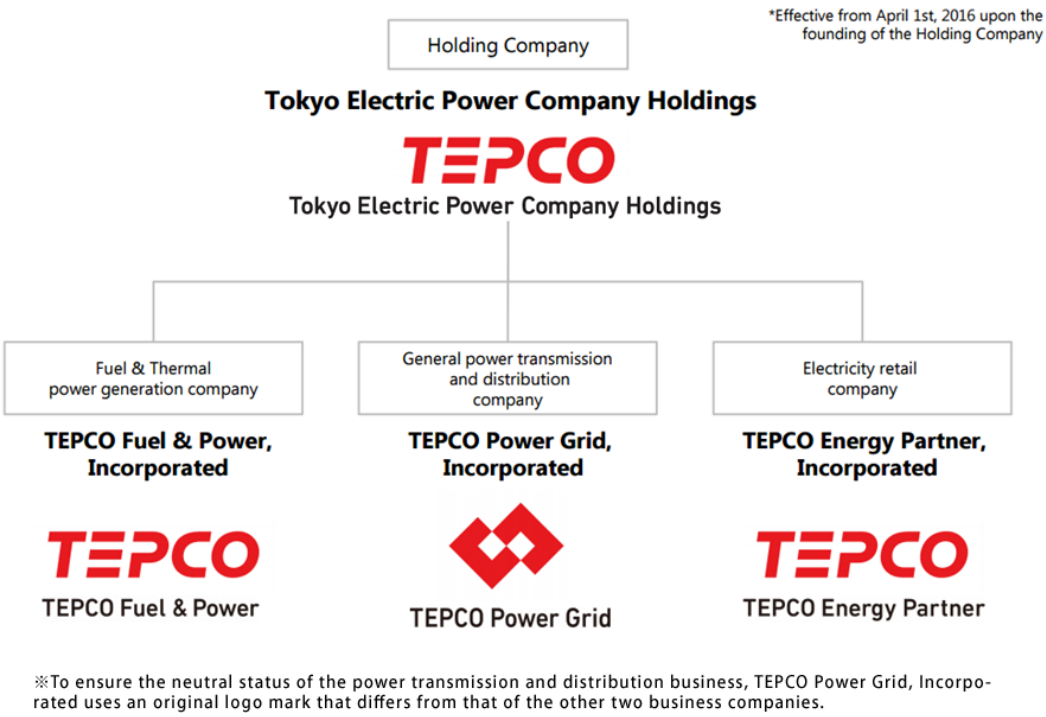
Figure 3 History of retail electricity market deregulation



Note: Okinawa EPCo's scope of deregulation was expanded from 20,000 kW, 60 kV or above, to include extra high voltage customers (2,000 kW or above, in principle) in April 2004.

Source: JEPIC 2017, p. 45

Figure 4 Structure of Tokyo Electric Power Company Holding



Source: TEPCO 2016

With the start of full liberalization a large number of operators entered the retail electricity market. As a result, a wide range of new rates menus are now being offered, including dual fuel (gas and electricity contracts), loyalty cards, points schemes and the supply of CO_2 free electricity.

On the other hand, in order to protect consumers, even after liberalization, consumers will be able to continue until April 2020 to buy electricity using the pre-liberalization rates. Those are regulated rates based on which the electric power utility had supplied them up to the start of liberalization.

A new system was also introduced in which conventional electricity business segments were divided into generation business, transmission/distribution business, and retail, and in which each business operator is issued with a license. Legal separation of the transmission and supply sectors is scheduled to be implemented in April 2020 (Figure 2). In this connection, Tokyo Electric Power Company (TEPCO) has been already unbundled. Some of other incumbents are expected to follow TEPCO's new structure (Figure 4).

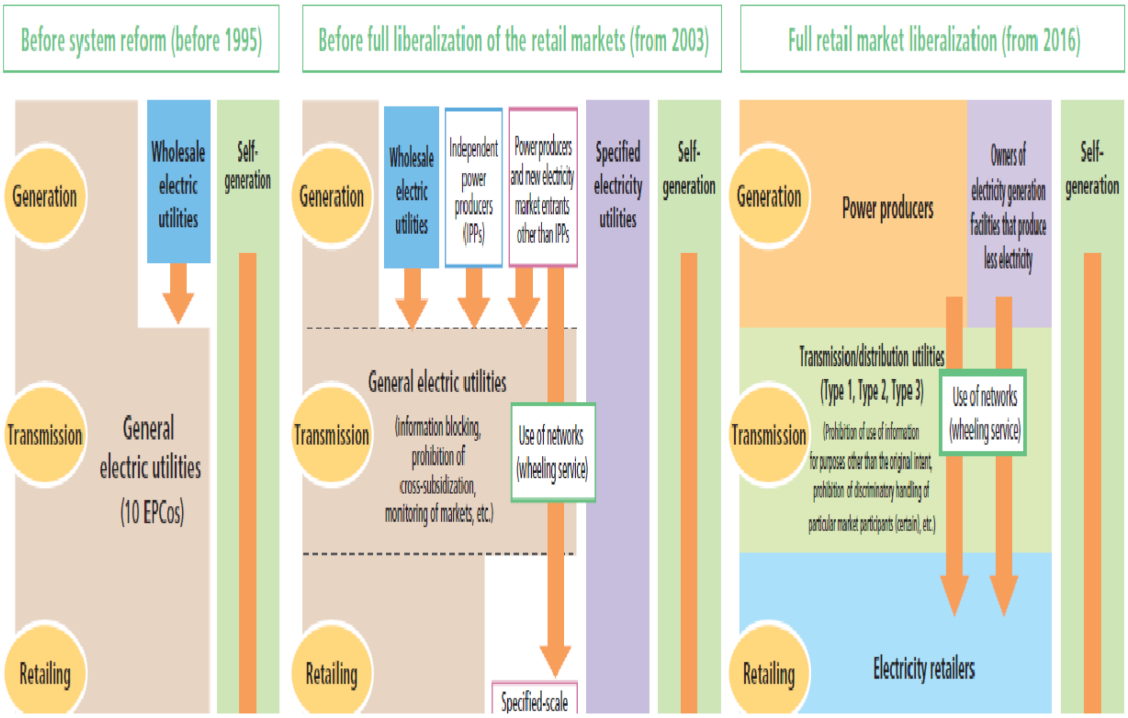
The structural reform of the electric power industry in general started with opening up the generating sector. Then, the transmission sector was the next step of the reform. However, in retrospect, the reform of the transmission sector was most difficult part. The history of liberalization overseas can be said to be the history of efforts to secure indiscriminate and comparable uses of transmission lines. In the US at first federal legislature enacted the Energy Policy Act to strengthen the authority of wheeling order by Federal Energy Regulatory Commission (FERC) in 1992. However, the Act was not sufficient to eliminate discriminating behaviors by the incumbents. What the US chose was ISO/RTO system to secure open access to the transmission lines. In the meantime, the EU adopted more stringent unbundling that is ownership unbundling or legal unbundling for some after series of regulatory reforms. Japan at first initiated the reform with the generating sector which was the same as other countries. The initial reform allowed the third party to enter the generating sector. The next step should have been the transmission sector as a common carrier. Yet, due to the reason concerned with politics, it was postponed until the market reform after the Earthquake in 2011. It can be said, therefore, that Japan is unique in that retail markets have been liberalized before implementation of unbundling and formation of the effective wholesale market.

Table 3 Types of electricity Market Operators

Business area	Outline
Electricity generation	The business of supplying electricity generated at self-maintained and operated generation facilities to retailers, general transmission/distribution operators, or specified transmission/distribution operators.
General electricity transmission/distribution	The business of utilizing self-maintained and operated transmission/distribution facilities to provide wheeling services and adjusted-generation-volume supply to the service area.
Electricity transmission	The business of utilizing self-maintained and operated transmission facilities to provide cross-area wheeling services to general transmission/distribution operators.
Specified electricity transmission/distribution	The business of utilizing self-maintained and operated transmission/distribution facilities to provide wheeling services to retail suppliers or retailers/general transmission/distribution operators at a specific service point.
Electricity retail	Retail supply business (supplying electricity in response to general demand).

Source: JEPIC 2017, p. 31

Figure 5 History of electricity Supply Structure



Source: JEPIC, 2017, p. 30

With the shift to a license-based system in April 2016, a comprehensive review of the classification of Japan's electric utilities has been carried out. Until then there had been General Electric Utilities (GEUs), Wholesale Electric Utilities, Wholesale Suppliers, Specified-scale Electricity Suppliers. GEUs were 10 electric utilities as shown in Figure 1 that were vertically integrated with their service area. Wholesale Electric Utilities were J-Power and JAPC and those utilities having generating facilities with a capacity of

2,000 MW or above and selling power on a wholesale basis to GEUs. Wholesale suppliers were IPPs who provided wholesale power through a bidding system by GEUs. Specified electric utilities are suppliers who supply electricity primarily to customers with power supply requirement of 20kV or above and contracted demand of 2000kW or above using transmission lines of GEUs. But under the license-based system, GEUs are divided into three further classifications: Electricity-generating operators, General Electricity Transmission and Distribution Operators and Retailers (Table 3).

After unbundling in 2020, Japanese electric power industry is expected literally to move to the competitive market for power. One scenario is integration of the industry. TEPCO's thermal generation section has already merged with that of Chubu Electric Company. Further consolidation of the industry is likely to happen. There is also possibility that a cross-border transmission line company is established.

2.1.3 Structure of and participation in electricity markets today

2.1.3.1 Wholesale electricity market

As of December 2016, total number of generating companies is 474. Total generating capacity in Japan is 273 GW, of which 84% is owned by incumbents which were vertically integrated electric utilities and wholesalers such as J-Power and JAEC. Fossil-fueled power plants accounted for 64% in terms of installed capacity. Excluding renewable energies, most of conventional thermal power plants such as LNG, Coal and Oil, and Nuclear and Hydro are owned by these incumbents (Figure 6).

Table 4 shows a more detailed breakdown of capacities (and generation) of incumbents and "others" for a different year. The latter is a class of independent power producers. Besides entities in the table, public utilities owned by prefectures have been supplying wholesale power to regional electric utilities (see section 7.1.1). Their supply sources are mostly hydro power plants. There are also wholesale suppliers of which some were established jointly by electric utilities and industrial customers. Since the incidence at Fukushima in 2011, the number of small-scale utilities affiliated with municipalities have been also increasing (see section 5.1). These utilities tend to utilize renewable energies. Figure 7 shows current generation mix. After the oil crisis in the 1970's, Japanese electric utilities made efforts to diversify power sources from heavy dependence on oil-fired generation. As seen from Figure 7, they achieved fairly balanced generation mix. Then the Great Earthquake hit Japan in 2011 and again the share of thermal power generation soared as a result of suspension of nuclear power generation caused by the accidents at the Fukushima Daiichi. In 2015, fossil-fueled thermal power plants accounted for more than 80% (Figure 8). In the meantime, most of nuclear power plants are not still in operation, so that nuclear accounts for only 1% of total generation. Renewable energies including hydro accounts for 14%.

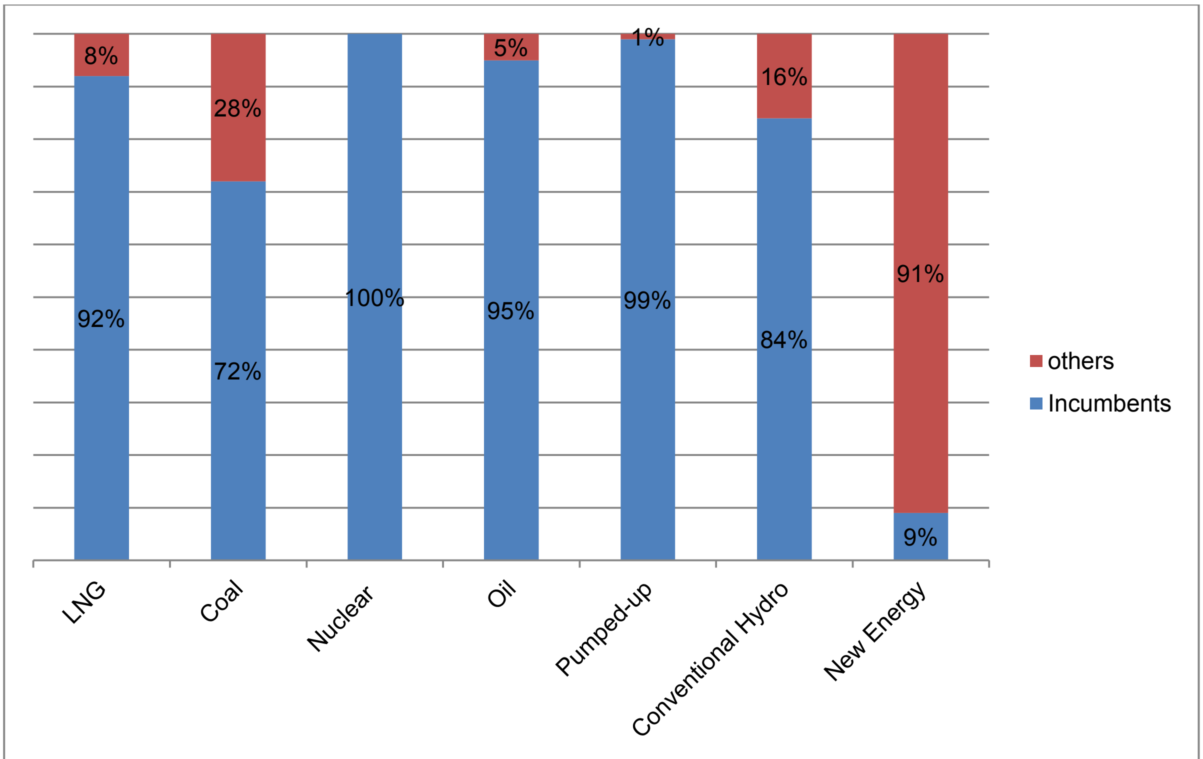
Table 4 Installed Capacity and Generation by Electric Utilities and Power Sources (As of March 31, 2016)

Company	Thermal		Nuclear		Hydroelectric		Wind		Solar		Geothermal		Total	
	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh
Hokkaido EPCo	4,214	22,158	2,070	-	1,647	3,502	-	-	1	1	25	129	7,957	25,791
Tohoku EPCo	12,025	57,211	3,274	-	2,428	7,921	-	-	5	6	224	925	17,956	66,064
Tokyo EPCo	44,279	198,179	12,612	-	9,859	10,868	18	19	30	35	3	11	66,802	209,113
Chubu EPCo	24,015	111,220	3,617	-	5,497	9,445	22	42	17	23	-	-	33,168	120,730
Hokuriku EPCo	4,400	22,330	1,746	-	1,921	6,561	4	1	4	5	-	-	8,074	28,896
Kansai EPCo	19,408	86,631	8,928	805	8,225	14,849	-	-	11	12	-	-	36,573	102,297
Chugoku EPCo	7,801	36,612	820	-	2,909	3,448	-	1	6	8	-	-	11,536	40,069
Shikoku EPCo	3,447	15,143	2,022	-	1,146	2,511	-	-	2	3	-	-	6,617	17,657
Kyusyu EPCo	10,206	47,516	4,699	8,632	3,584	4,804	3	2	3	4	206	1,296	18,701	62,253
Okinawa EPCo	2,153	6,806	-	-	-	-	2	2	-	-	-	-	2,155	6,808
Subtotal	**131,948**	**603,806**	**39,788**	**9,437**	**37,215**	**63,910**	**50**	**67**	**78**	**96**	**458**	**2,361**	**209,537**	**679,678**
J-POWER	8,374	58,822	-	-	8,570	10,997	-	-	-	-	15	23	16,959	69,842
JAPC	-	-	2,260	-	-	-	-	-	-	-	-	-	2,260	-
Others	2,718	13,023	-	-	1	6		-	9	3	-	-	2,728	13,032
Total	**143,040**	**675,650**	**42,048**	**9,437**	**45,786**	**74,914**	**50**	**67**	**87**	**99**	**473**	**2,384**	**231,484**	**762,551**

Note: without auto-producers

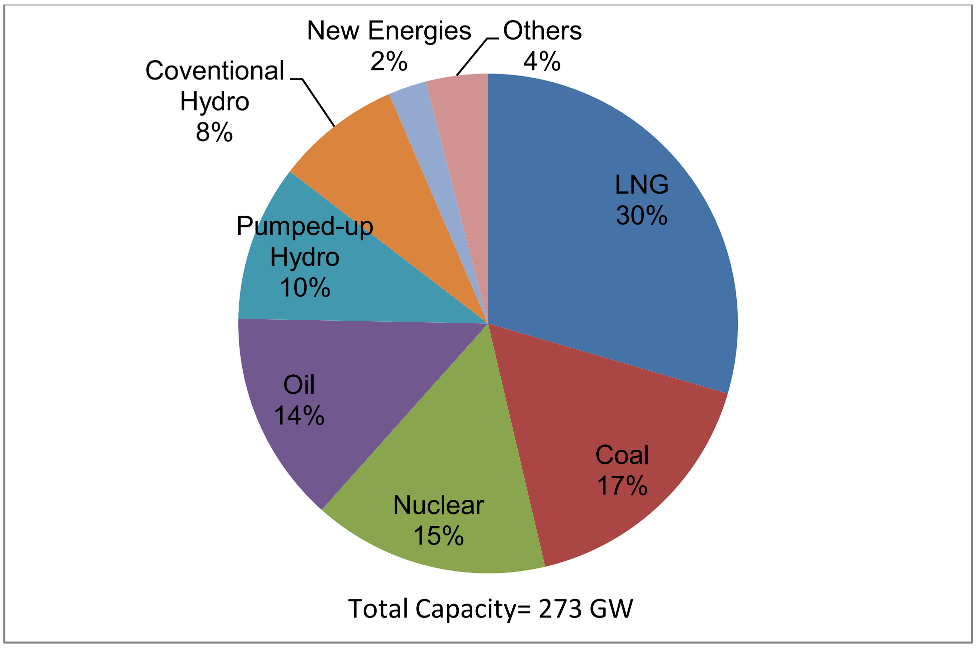
Source: FEPC, FY 2015

Figure 6 Ownership of Generating Sources



Source: EGMSC 2017b, 2017a

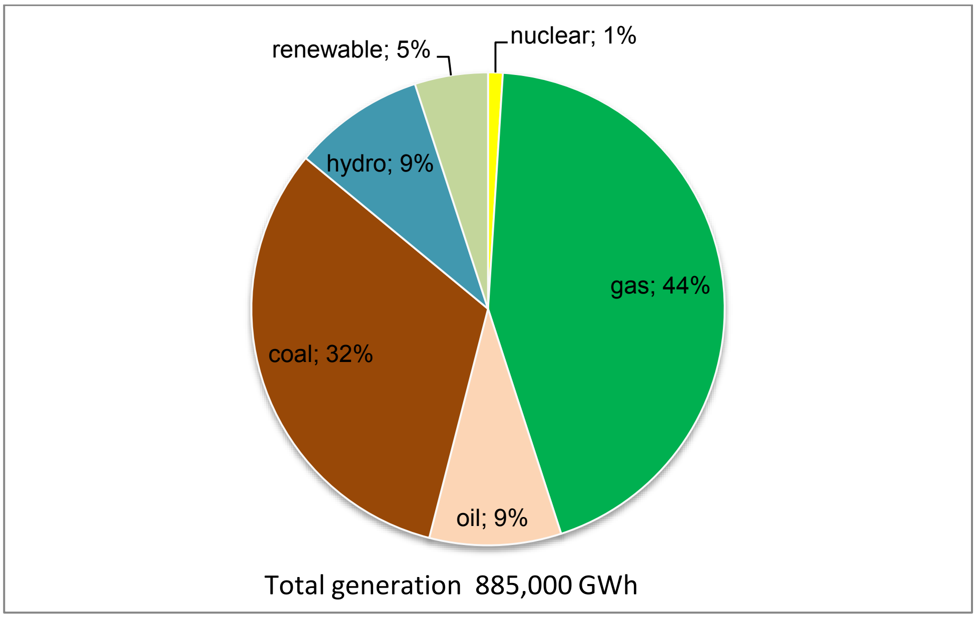
Figure 7 Composition of Generating Capacity in Japan by fuel



Note: includes auto-producers

Source: METI 2017

Figure 8 Electricity Generation Mix in Japan (2015)



Note: includes auto-producers

Source: METI 2017

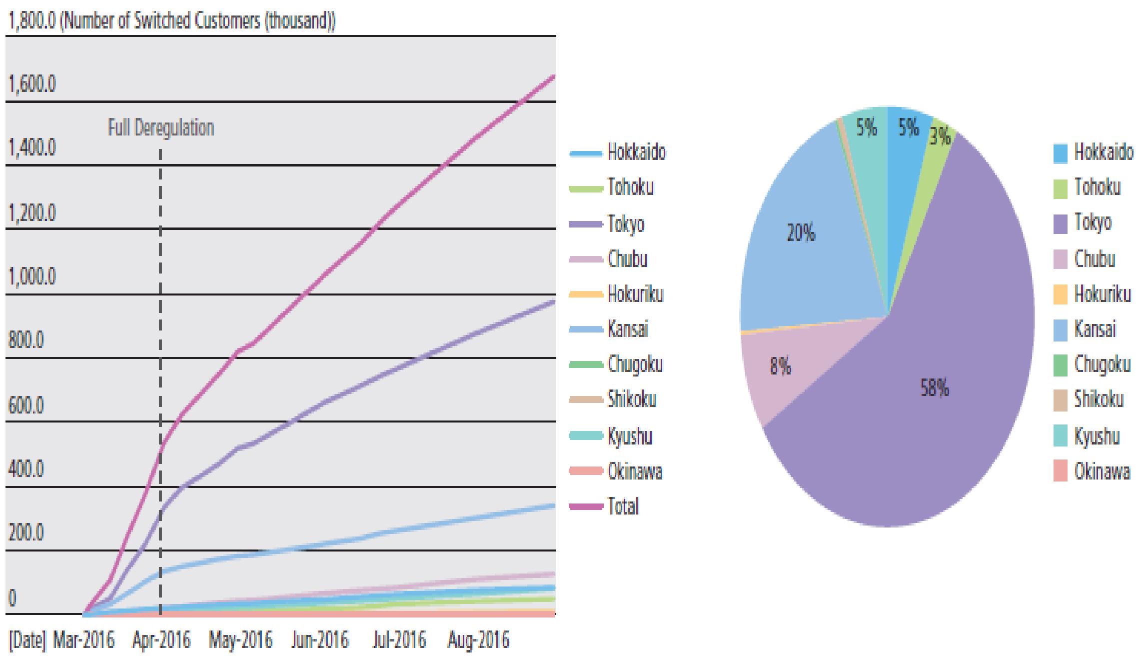
2.1.3.2 Retail electricity market

2.1.3.2.1 Market concentration and switching trends

Since the full deregulation of retail supply of electricity in April 2016, all customers have been able to select which EPCO to use. The situation regarding such selections can be examined by looking at switching as an indicator. Trends in switching are shown in Figure 9. In the context of this graph, switching refers to changing from an incumbent to a retail power company; it does not include changing to unregulated-rate contracts offered by incumbents' retail power companies. By the end of October 2016, about 1.8 million customers or 2.9% of total customers changed a retail power company (Table 5). Those incumbents' customers who changed the contract type from regulated to unregulated rates without changing a retail power company accounted for 3.2% or 2 million customers.

Looked at by region, the largest proportion of switched customers, 59%, reside within Tokyo Electric Power Company (TEPCO) service area, followed by Kansai (20%) and Chubu EPCO (8%), reflecting an intensification of efforts to acquire customers in major metropolitan areas like Tokyo, Osaka and Nagoya.

Figure 9 Switching Trends by Region



Source: compiled data from various press releases of OCCTO

Table 5 Number of Switching Cases for Low Voltage Customers by Region

Area	Number (ten thousand)	Share of total contracts for low-voltage customers (%)
Hokkaido	9.1	3.3
Tohoku	5.4	1.0
Tokyo	106.2	4.6
Chubu	13.5	1.8
Hokuriku	0.6	0.5
Kansai	37.1	3.7
Chugoku	0.4	0.1
Shikoku	1.1	0.6
Kyushu	7.7	1.2
Okinawa	-	-
Total	181.1	2.9

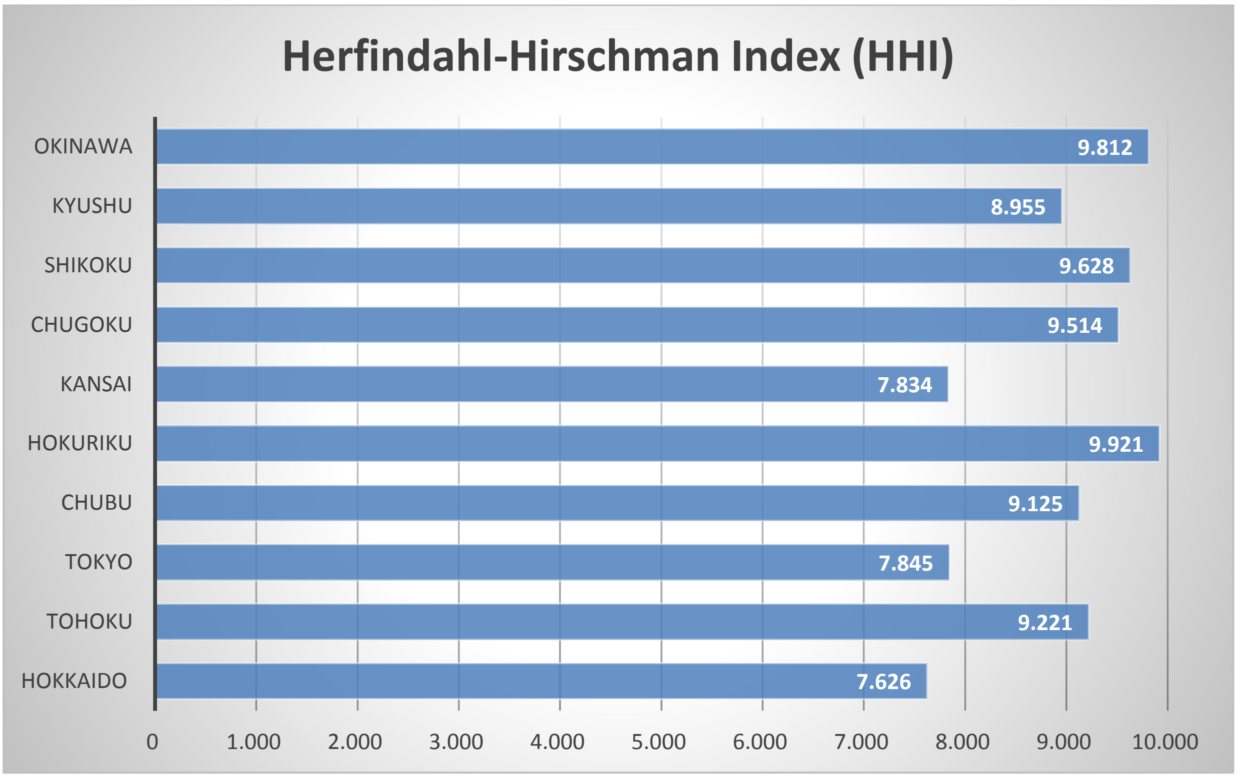
Note: number of total contracts for low voltage customers including households ~62.5 million.

Source: ANRE 2017d

As shown in Figure 11, the share of a retail power company as a new participant in the class of large customers (extra-high and high customers) had been around two to three percent for over ten years since partial retail liberalization was implemented in 2000. From around 2014 the share begun to rise and now stands at over 10%. Including newly liberalized market, the share of a new retail power company is about 8% as of October 2016.

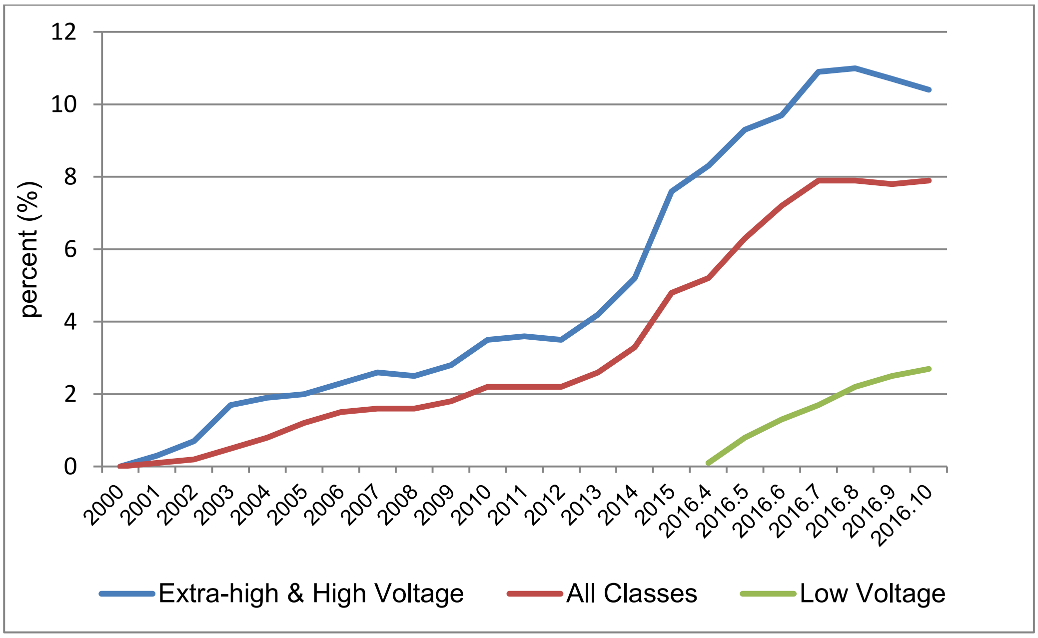
Figure 10 shows the level of market concentration in the retail market of each area. The Herfindahl–Hirschman-Index (HHI) is a commonly accepted measure of market concentration. It is calculated by squaring the market share of each firm competing in the market and then summing the resulting numbers. If the number is 10,000, then it is perfect monopoly while zero means perfect competition. HHI is very high in all areas. Assuming that the market in Japan is a single market, HHI is 1,521. However, in light of shortage of interconnectors between areas resulting in market splitting, HHI will remain high for the foreseeable future.

Figure 10 Market concentration in Japan's retail market



Source: EGMSC 2017c; as of Sept. 2016

Figure 11 Share of New Retailers (nr. of supply)



Source: ANRE 2017d

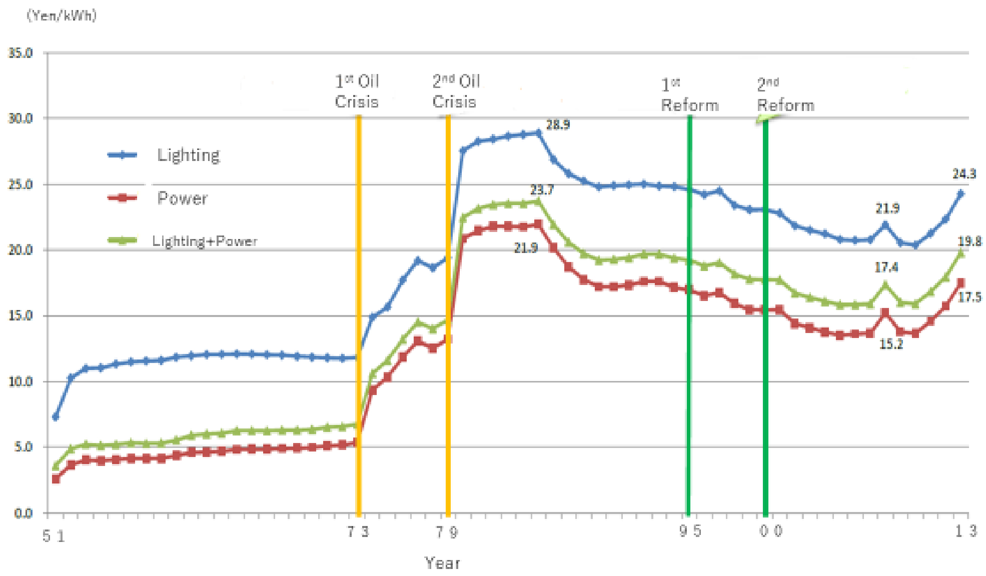
It is common for contracts for high-voltage (6 kV and above), which have been deregulated since before April 2016 to be negotiated between the retail company and each customer to decide on the contract details and unit prices, based on projected electricity usage and actual circumstance. The EPCOs, which have traditionally served as general utilities for retail electricity supply, strove to handle customers of this kind by strengthening their business capacity, through efforts such as establishing specialist organizations, increasing personnel to take charge of business for corporate customers, and implementing business training. For example, for each major customer they implement a service which involves assigning them a specialist business manager and increasing the frequency of customer contact so that their needs can be suitably met, as well as diagnosis and analysis of the customers energy usage, in concert with the supply and technology sectors, and making proactive proposals regarding the efficient use of energy.

2.1.3.2.2 Electricity rate trends

In Japan, electricity rates had been regulated based on the cost-of-service since 1933. In terms of the rate design, the first oil crisis in 1973 brought three-steps increasing block rate system to promote electricity conservation (i.e. prices per kWh increase with rising consumption). Another major modification in the rate design was introduction of the fuel costs adjustment clause in 1994 to reflect changes in oil prices and foreign exchange rates promptly to stabilize the financial condition of electric utilities.

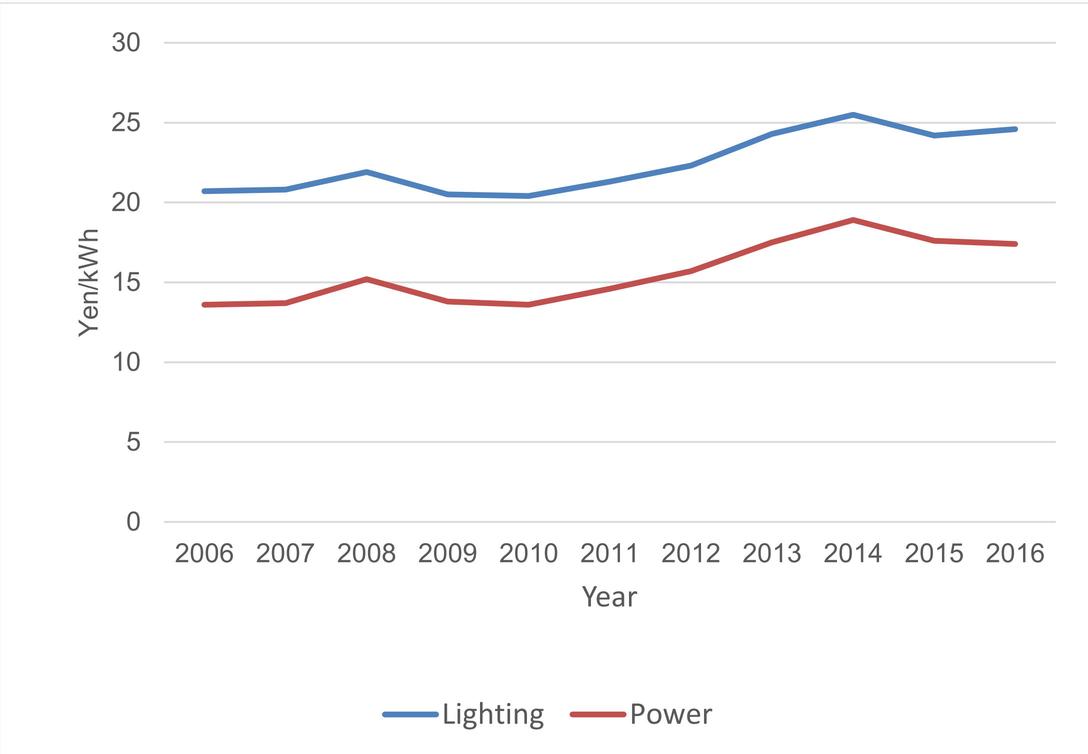
Figure 12 shows electricity rates over the years since 1951 when nine regional electric utilities were established. As shown, electricity rates skyrocketed when two oil crises hit Japan in 70’s. After 90’s, rates were on the downward trend. According to the analysis by the government (ANRE 2017e), structural reform contributed to reduce electricity rates. Specifically, the costs of depreciation, maintenance and labor excluding fuel costs decreased by approximately 40% from 1995 to 2013. Then, the earthquake in 2011 hit utilities. Huge amount of wealth flew out of Japan to import fuels to replace nuclear power generation. Electricity rates increased 20% for lighting use and 30% for industrial use in 2016 comparing to pre-earthquake level of electricity rates (Figure 13).

Figure 12 Electricity rates Japan



Source: ANRE 2017e

Figure 13 Electricity rates in Japan after the 2011 Earthquake



Source: ANRE 2017c

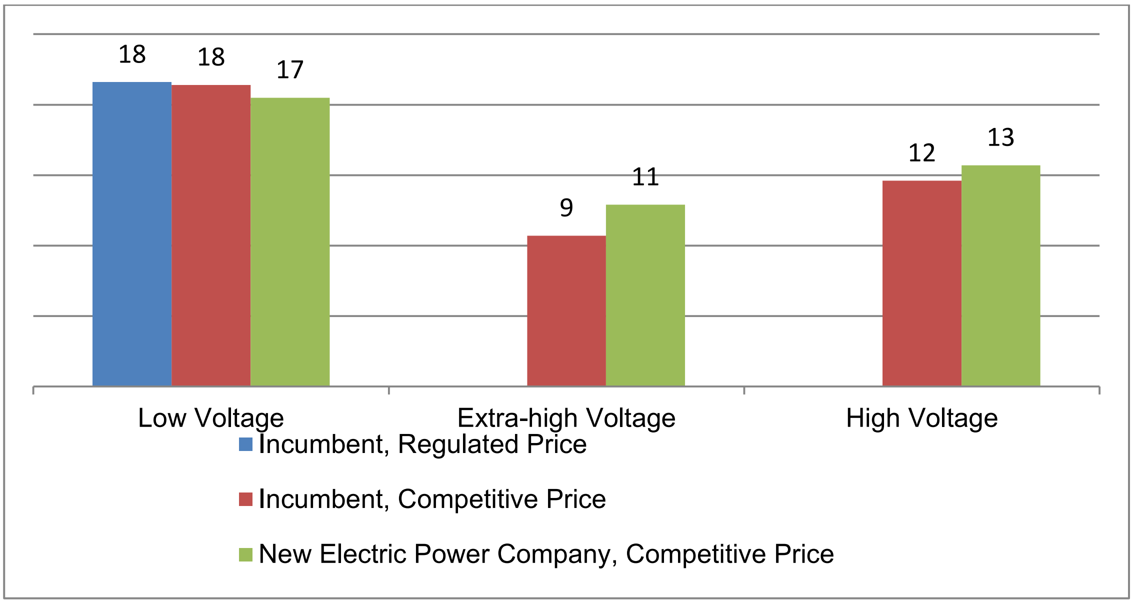
Experiences in other countries which implemented full liberalization much earlier have not proved yet that competition worked effectively for the purpose of lowering electricity rates or restrain rate increases. Furthermore, at the present stage in Japan where full-fledged competition in both wholesale and retail markets is yet to be realized, it is necessary to wait for more data for analysis. Therefore, the analytical results below are obviously not conclusive.

From April to September in 2016, average unit prices in most of regions decreased. Reduced prices were brought about by lowered fuel prices through the fuel adjustment clause. This clause was adopted in 1996 to reflect in electricity rates uncontrollable external factors such as changes in fuel prices and foreign exchange rates.

For the class of low-voltage customers, average regulated prices offered by incumbents are higher than their competitive (non-regulated) prices that are in turn higher than rates offered by new retail power companies.

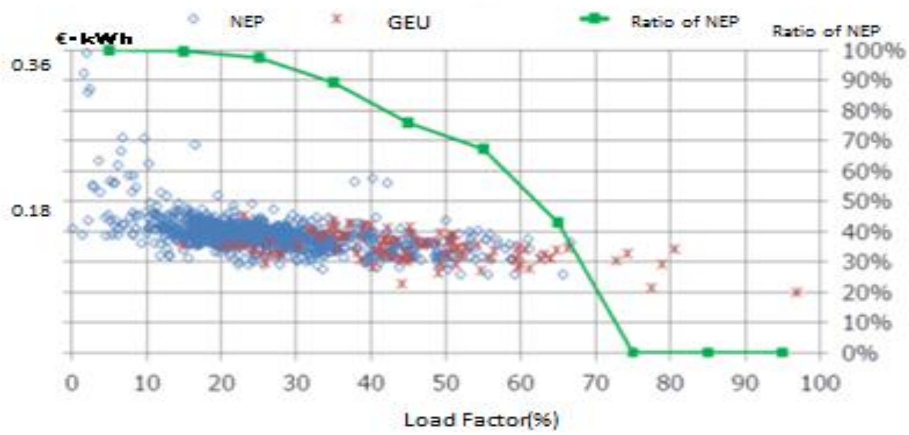
Comparing prices of extra-high voltage and high voltage customers, an average supply price of a new retail power company is higher than that of incumbents (Figure 14). The reason, according to the government, is considered to be due to attributes of customers.

Figure 14 Comparison of Average Electricity Prices of Incumbent and New Participant by Customer Class; unit; € cent



Source: EGMSC 2017b

Figure 15   Relationship between load factor and successful bidder



*Note: * NEP: New Electric Power Company (New retail power company); ** GEU: General Electric Utility (Incumbent)*

Source: EGMSC 2017b

Figure 15 shows the results of competitive bidding by public authorities conducted in 2014. As shown clearly by the figure, General Electric Utilities (Incumbents) tend to win in the bidding for customers with higher load factors. In the meantime, a new retail company won in the bidding for customers for lower load factors.

General Electric Utilities own 270 GW (2015) generating capacity of which more than 30% is base-load generating plants including nuclear, coal and hydro. On the other hand, new retail companies have only 12 GW of generating capacity composed of limited amount of coal-fired power plants and hydro for base-load accounting for about 11% of generation mix, and LNG-fired power plants for middle-load. That demand which new retail Companies won in bidding is characterized by high average prices and low load factors. This result may reflect the fact that new retail companies do not have enough base-load generating power plants.

2.1.3.2.3   New participants in the retail market and their supply sources

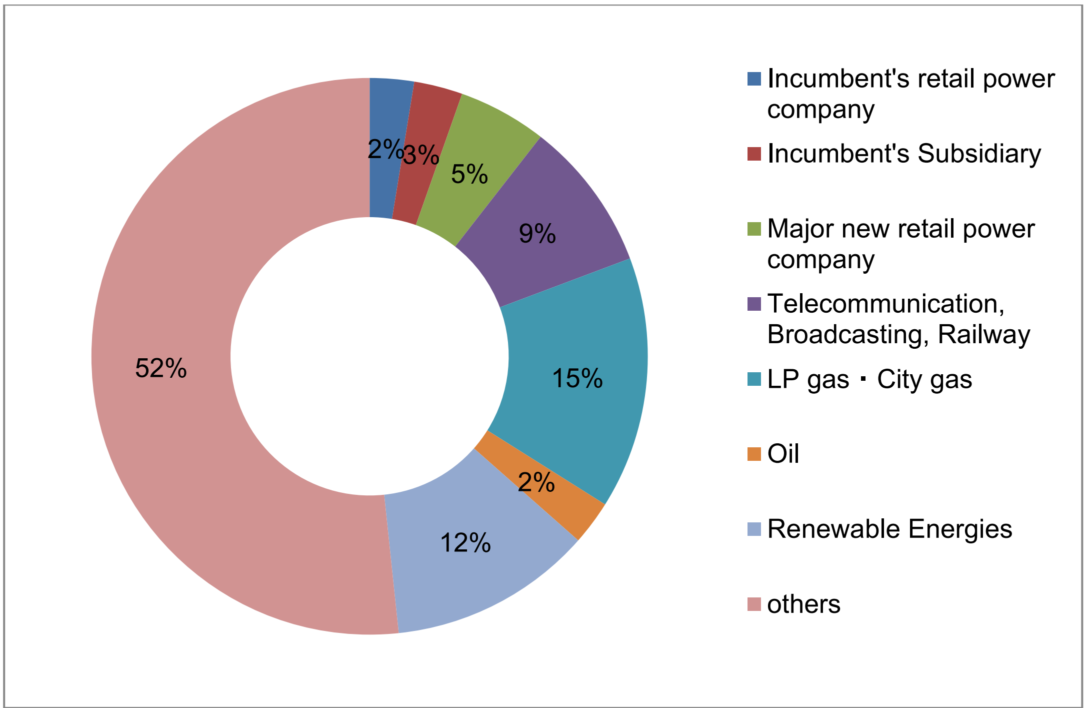
As of March 2017, the number of registered retail power companies including incumbents' retail companies was 389.

Figure 16 shows affiliations of retail power companies. As of September 2016 incumbents' retail power companies accounted for 92% of total electricity supply. Among retail power companies excluding incumbents' retail power companies, top 5 companies accounted for about 65 % of electricity supply by these retail power companies. They are gas and telecommunication companies that have their own generating plants.

Retail power companies as new participants procured 61.5% of power sources from bilateral trade in 2014. Self-supply by their own generating power plants was 4.1% while procurement at JEPX was 10.6%. The balance, 23.8%, was firm back-up power from incumbents (ANRE 2016b). Firm back-up power system is the contractual agreement in which incumbents supply power to a retail power company with shortage of power. This system which helps a retail power company to procure power sources is unique to Japan and can be considered as application of asymmetric regulation.

Some of retail power companies such as gas companies have their own generating capacity. 19 relatively large-scale companies with electricity supply of more than 100 GWh and 49 middle-scale companies with 10 GWh~100 GWh have their own generating capacities and supplied 9% and 10% of their electricity in September 2016. In the meantime, the share of self-supply for 180 small-scale retail suppliers was only 3% (ANRE 2017b).

Figure 16 Retail Power Companies by Affiliation

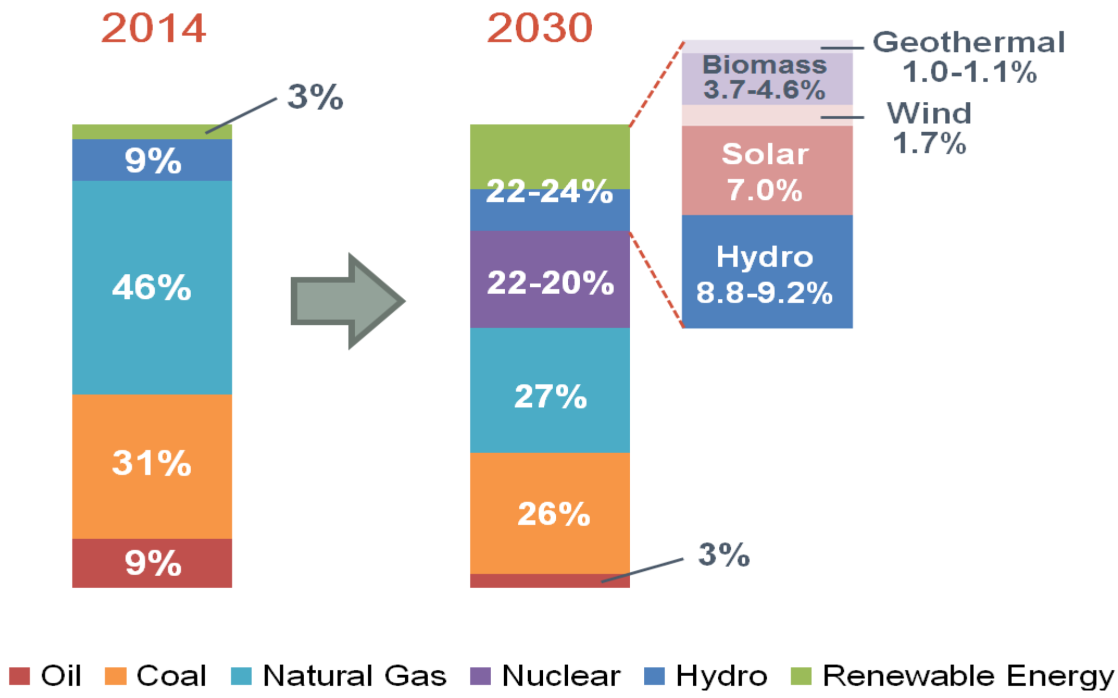


Source: EGMSC 2017c

2.1.4 Energy transition: Long-Term Energy Supply and demand Outlook

The Long-term Energy Supply and Demand Outlook formulated by the government in July 2015 based on the fourth Basic Energy Plan indicates that by fiscal 2030, the government aims to have renewable energy account for approximately 22%-24% of total electric power generation and nuclear energy for approximately 20%-22% (Figure 16). However, even if all of the nuclear power plants that are currently shut down are restarted, if the extension of the operation period of nuclear power plants that have been in service for 40 years or more is not approved, it will be extremely difficult to achieve the stated nuclear power generation target. The way in which the service life extension of nuclear power plants and the issue of new or additional facilities are handled in the next Basic Energy Plan will be of crucial importance.

Figure 17 Electricity Generation Mix (kWh)



Source: METI 2015

2.2 Germany

2.2.1 The starting point

Similar to Japan the German electricity sector before liberalization was organized in nine regional monopolies with nine regional integrated suppliers who dominated generation and transmission. Further, there were around 70 regional and 400 municipal utilities. Each group represented one third of the retail business. Investments and tariffs were regulated. For that purpose, the energy sector was explicitly exempt from the anti-cartel regulation so that regional monopolies and collusion was allowed. Until 1998 this had not really changed despite various reform attempts of the German anti-cartel-law. The issue gained more thrust via European regulations in the 1980's for a common European market (e.g. single European Act) that finally led to the various EU directives mentioned below. (Löwer 1992, pp. 201–205).

The concept of liberalizing the energy sector is based on the idea that greater market orientation and competition increases efficiency and lowers energy prices. This implies the division of vertically integrated electricity companies that comprises the entire value chain from energy generation (power plants) over trade (wholesale) to distribution (transmission and distribution grids) to retail (supply) into economically autonomous units. Ideally this creates markets on each stage of the value chain allowing new players to enter. The electricity grids, however, usually constitute a natural monopoly since a single electricity grid is more economical to operate than multiple parallel grids. Therefore, network operation needs to be regulated and competition between the network operators "simulated" to ensure equal market access (Correljé und Vries 2008; Matschoss und Haas 2017; Matschoss et al. 2017, Ströbele et al. 2010, 2010, ch. 12).

The German process of energy market liberalization needs to be seen in conjunction with the European policy process. Many German laws and ordinances in this respect transpose European legislation. German policy (like other EU member states) on the other hand does influence the European policy process. That is, on the one hand European legislation represents a compromise of the member states. On the other hand there is different implementation of EU legislation by the member states (Haas et al. 2006).

2.2.2 The process of electricity market liberalization in Germany

2.2.2.1 First wave of liberalization 1998-2005: mixed results

The implementation of the first EU directive on the liberalization of energy markets (approved in 1996) led to a fundamental revision of the German energy act ("law on energy business", Energiewirtschaftsgesetz, EnWG) in 1998 that existed since 1935. Before 1998 the German electricity market was structured by nine vertically integrated suppliers with regional monopolies. The reform aimed at abolishing the regional monopolies and liberalizing generation, transmission, distribution and retail. (Brunekreeft und Bauknecht 2006, pp. 240–241; Energiewirtschaftsgesetz von 1978). The results of this reform where mixed, however. Unbundling of the nine vertically integrated suppliers was not really enforced. Moreover, market concentration was even rising.

In *generation* (i.e. wholesale) the rising market concentration was particularly obvious. Before 1998 the nine integrated suppliers owned a bit more than 80% of the German generation capacity. After that, a wave of mergers & acquisitions started not only in Germany but all over the central European market (Haas et al. 2006, p. 287, Fig. 9.4). In 2000 there were mainly four German suppliers left who owned around 90% of German generation capacity (Brunekreeft und Bauknecht 2006, pp. 240-1, Table 8.2). These are sometimes called the “big four” (see section 5.2.1.1). Between 2003-2005 their market share varied between 80-90% (BNetzA 2007, p. 60). There were almost no new generation capacities from new players for several reasons: First, there where almost no new plant sites. Second, wholesale prices where low due to overcapacities. Third, negotiated grid access created a bias against third parties (see below). This led, fourth, to complaints about discrimination against third parties. Fifth, there where specific problems related to gas-fired capacities (Brunekreeft und Bauknecht 2006, p. 247).

Due to the high market concentration the European Commission had severe concerns that large national utilities used their market dominance to manipulate German electricity markets. In 2006 it opened antitrust procedures against two companies (RWE and E.ON) (Gammelin 2006). As one of the results the E.ON company sold around 4,800 MW generation capacity and divested and sold its transmission network to resolve the conflict with the European Commission (European Commission 2008, pp. 14–15). A later sector inquiry by the German antitrust agency concluded that a presumed strategic withholding of power plant capacities, which could have been operated according to merit order, was too limited to indicate abusive market behavior (Bundeskartellamt 2011, p. 24).

In *network access* the EU directive left the member states the choice between regulated or negotiated grid access. Regulated grid access implies the establishment of a regulatory authority that ensures non-discriminatory access to the grid. Negotiated grid access, on the other hand, leaves this to the market players and requires the newcomers to negotiate the conditions of grid usage (fees etc.) with the incumbent and assumes that a cartel office would suffice to prevent the abuse of market power. The 1998-reform obliged the German vertically integrated suppliers to provide non-discriminatory grid access to third parties (BNetzA 21.1.15, p. 39). However, Germany as the only EU member state opted for the negotiated grid access. It was trusted that collective arrangements by so-called association agreements (Verbändevereinbarung, VV) negotiated by associations from the power sector would suffice. However, these merely laid down the principles but not the fees themselves (Brunekreeft und Bauknecht 2006, pp. 241–242; Haas et al. 2006, pp. 277–280). Obviously, negotiated grid access implies asymmetric information between the incumbent (the vertically integrated supplier) and the third party resulting in a lack of bargaining power for the latter. Furthermore, even if grid fees are exaggerated but the same for all participants (i.e. non-discriminatory) the vertically integrated supplier has the possibility to cross-subsidizes its own generation capacities since the fees are paid within the own structure (Brunekreeft und Bauknecht 2006, p. 246).

Retail markets where officially liberalized with the 1998-reform but the above mentioned VV led to prohibitively high fees for new distributors or their customers, respectively. Furthermore, there was non-cooperative behavior on all levels so that the process of changing the supply took unduly long. Systematic market monitoring by the network agency and the cartel office only started in 2005 but consumer protection organizations reported on the difficulties to change suppliers in the first years and due to these difficulties third party distributors were suing DSOs (Test 25.5.00; Yello 20.11.01).

Taken together, the first round of liberalization left a situation with an even more concentrated wholesale market of vertically integrated suppliers. Formally, there was a right to access the grid for third parties but this right was difficult to exercise at competitive conditions. Due to the weak regulation there were incentives for the vertically integrated suppliers to exercise margin squeeze out of networks and leave generation prices low in order to keep off third parties. However, there was some degree of internal competition (contestable markets) with some re-negotiations of old contracts (Brunekreeft und Bauknecht 2006, p. 252; Haas et al. 2006, 280). Furthermore, the antitrust activities of the European Commission led to a partial reduction of the market concentration.

2.2.2.2 The second and third wave of Liberalization in 2005 & 2009 & further reforms

The *second EU-package* on energy market liberalization – that included the so-called acceleration directives – forced Germany to another fundamental revision of the EnWG in 2005.

Grid regulation, again, was a major aspect. The negotiated grid access was abolished and the regulated third party access together with a regulatory agency (Bundesnetzagentur, BNetzA) was introduced. The system of balancing groups (see section 3.1.2) was introduced in the course of an ordinance that regulates equal access to the electricity grids (Stromnetzzugangsverordnung StromNZV). Germany opted for an incentive regulation to govern the specific design of network regulation. This was created through an ordinance (Anreizregulierungsverordnung, ARegV) that entered into force in 2007 and regulates the grid operator's revenues rather than their costs (see section 4.3.2).

The enforcement of *unbundling* of the vertically integrated suppliers is another fundamental aspect of the acceleration directive. There are different degrees of unbundling. The slightest form is informatory unbundling requiring the division of sensible data like e.g. customers' data. Unbundling of accounting requires separated accounts in order to prevent cross-subsidies. Organizational unbundling requires the division of the organizational and management. Legal unbundling means the separation of generation, networks and retail in legally independent units. Ownership unbundling, finally, as the most far reaching form of unbundling, would require the integrated suppliers to sell of parts of the value chain (§§ 6-10e EnWG). With the 2005-reform the energy act requires legal and operational unbundling. However, it exempts DSO with less than 100,000 customers from the legal unbundling rule leading to the exemption of 90% of the DSO (see section 4.3.2).

For *retail*, the 2005-reform meant the starting point of true liberalization. Regulated network access and the system of balancing groups enabled the division of the physical from the business side. However, it took a while until the structural change was actually implemented and market activities took pace. The first monitoring report still reported average switching costs of around 108€ or 14,781 yen in 2005 and just around 826,000 customers changing their suppliers. The quota of changing suppliers in terms of energy (TWh) was also low but strongly differentiated between customer groups: Whereas around 11% of industrial electricity consumption (both medium and large customers) changed the supplier, only around 2% of private household consumption made that step. (BNetzA 2006, p. 12). In 2006 the switching cost have already fallen to 65€ or 9,493 yen for customers with standardized demand profiles (i.e. "normal" household customers) which is due to the regulatory agency's mandatory standardized definition of processes and data formats for switching processes between suppliers (BNetzA 2007, pp. 73–75).

The transposition of the *third EU-liberalization package* of 2009 required further reforms of the German energy act in 2011. Again, the package called for stricter unbundling rules. Today, three of four TSOs are ownership unbundled and one operates as an independent transmission system operator (BNetzA 21.1.15, S. pp. 68–69). Other aspects of the third package that where transposed into the energy act and accompanying laws include the liberalization of metering and consumer protection.

In 2015 the European Commissions announced a new long-term strategy called the "Energy Union". One of its main goals is a fully integrated energy market and stresses the full implementation of the third liberalization package, in particular with regard to unbundling (European Commission 25.2.15, p. 9). Further, it puts market design issues in the context of decarbonization as one of its main goals.

2.2.2.3 Liberalization and Market design: the target model for the internal electricity market

In terms of market design the vision of the *target model* for the European electricity market (similarly for the gas market) was formulated in the course of the various liberalization efforts (Glachant 2016). This alignments of rules and institutional structures i) to a common system via market coupling and ii) to the necessities of the future (increased efficiency, consumer benefit, RES-integration) is referred to as the market's "software". Improving physical interconnections and infrastructures, on the other hand, are called the markets "hardware" (European Commission 25.2.15).

Most member states chose the decentralized exchange-model where market participants can trade independently of physical fulfilment in the electricity networks. The Nordic countries chose the centralized pool-model, however, that has also been introduced in a number of US-electricity markets and elsewhere around the world. Here, the network operator administers the trade according to network restrictions (Ockenfels et al. 2008, pp. 10–12).

Important aspects of the target model include linkages between electricity wholesale and retail markets in order to transport scarcity signals so that consumers can react to it. This is in order to ease EU-wide electricity trade and strengthen short-term trade. To better integrate VRE the target model foresees the following market coupling activities: European market coupling ("the software") involves the following aspects: i) improved common capacity calculation method for interconnectors, ii) long-term: single access point for transmission rights, iii) single day-ahead market coupling and iv) single platform for intraday cross-border trade (ACER 2013; ENTSO-E 2014, 4). These technical issues are solved within different electricity regional initiatives (ERI), i.e. neighboring countries that are physically connected to the German electricity market via with electricity interconnectors ("electricity neighbors"). These coordinate also across the regions (CEER 2017). Germany is a member of the Pentalateral Energy Forum that represents the Central Western Region (CWE – Austria, Benelux, France, Germany and Switzerland) and their TSO's and co-operates since 2007 in order to deal with the technical details necessary to implement the European target model (PLEF 2007, 2015b).

2.2.3 Structure of and participation in electricity markets today

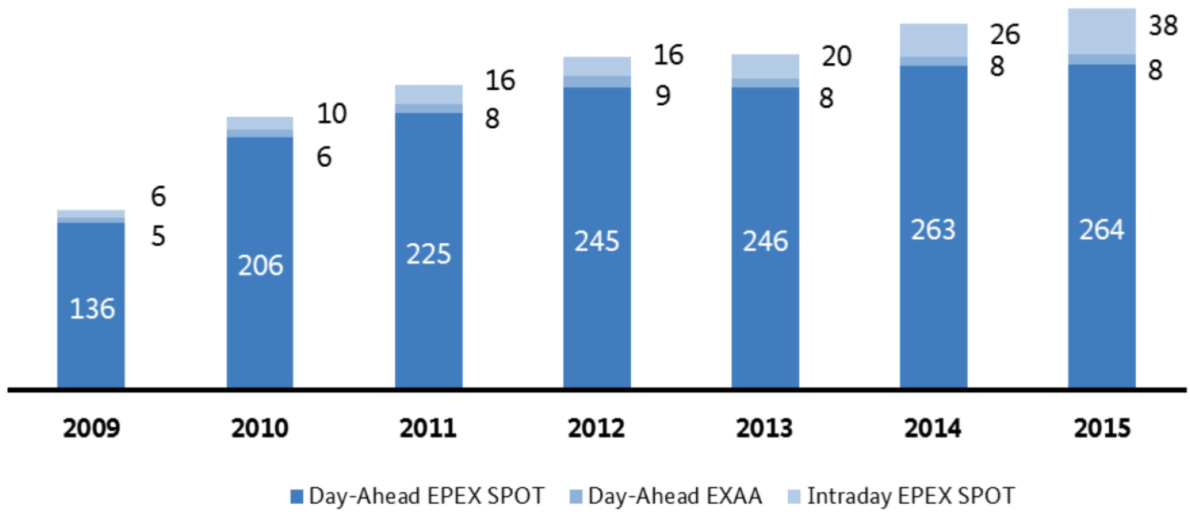
As mentioned above, consumer protection was increased with the transposition of the third EU-package. For this, the German antitrust law (Gesetz gegen Wettbewerbsbeschränkungen, GWB) was extended in 2012 to establish a common market transparency platform (Markttransparenzstelle) under the common auspice of the federal cartel office (Bundeskartellamt, BKartA) and the federal network agency (Bundesnetzagentur, BNetzA). Since then BNetzA and BKartA cooperate on the annual monitoring reports that also describes the structure of stakeholders in the energy markets. This sections describes the state as of 2015.

2.2.3.1 Wholesale electricity market

The wholesale market can be looked at from the side of physical as well as financial trade. The concentration of electricity production (primary electricity market) in the German/Austrian market area has been sinking since the first wave of liberalization (see above) but still remains high. Here the so-called “big four”, i.e. the former integrated utilities RWE, Vattenfall, EnBW and E.ON still hold a common market share of 69.2% in 2015. However, with the decision on the nuclear exit until 2022 concentration is expected to decrease further. Market power is further limited due to (i) conventional overcapacities (GER and EU), (ii) rising RE-capacities, and (iii) rising possibilities to import electricity with rising connectivity. (BNetzA und BKartA 2016, pp. 35–36). Furthermore, short-term trades (i.e. of physical energy) following the primary electricity market are far less concentrated. The number of participants has been steadily rising since 2007. In 2015 it reached 213 at EPEX Spot and 74 at EEXA (Austria, Spot). In turn the five largest buyers and sellers at EPEX SPOT in 2015 reach a combined shares of 39% and 35%, respectively, which is considered uncritical. It can be assumed, that the number of participants is actually larger since a number of participants represent traders that offer their services to third parties. In 2015 community utilities also took part with 25 participants at EEX and 63 participants at EPEX Spot (BNetzA und BKartA 2016, p. 162). A large fraction of energy, however, is traded not via the exchange but in bilateral trades (over the counter, OTC) (SRU 2013, p. 31). Furthermore, as a large number of trade a purely financial, the financial (see section 3.1.2.1) volume is much larger than the physical electricity flows resulting from it.

In terms of financial trade one function is to hedge against future risks. This is executed via the EEX. Here, too, the number of participants has been steadily rising since 2007 and reached 194 in 2015. Of special interest at the EEX are so-called market makers (trading companies that submit to simultaneous acquisition and supply) as they increase market liquidity. The four largest market makers at the EEX are E.ON, RWE, Vattenfall Energy Trading GmbH and French EDF Trading Limited with a combined share of 33% Phelix Futures. (BNetzA und BKartA 2016, pp. 20, 175).

Figure 18 Development of Spot-market-volumes at the EPEX Spot



Source: BnetzA 2016, Monitoringbericht, p. 165

Taken together, limitation of market power of incumbents depends on physical measures as well as on market design measures. On the physical side, the energy transition induces a shift in ownership of capacity away from incumbents (nuclear phase out) towards newcomers (RES-policy) as a by-product. On the market side, an open grid access policy together with better market integration (new products, more short-term trade) also enables more newcomers. The issue of better connection to other market areas (abroad or within the same country) has a physical (grid) and market dimension as well.

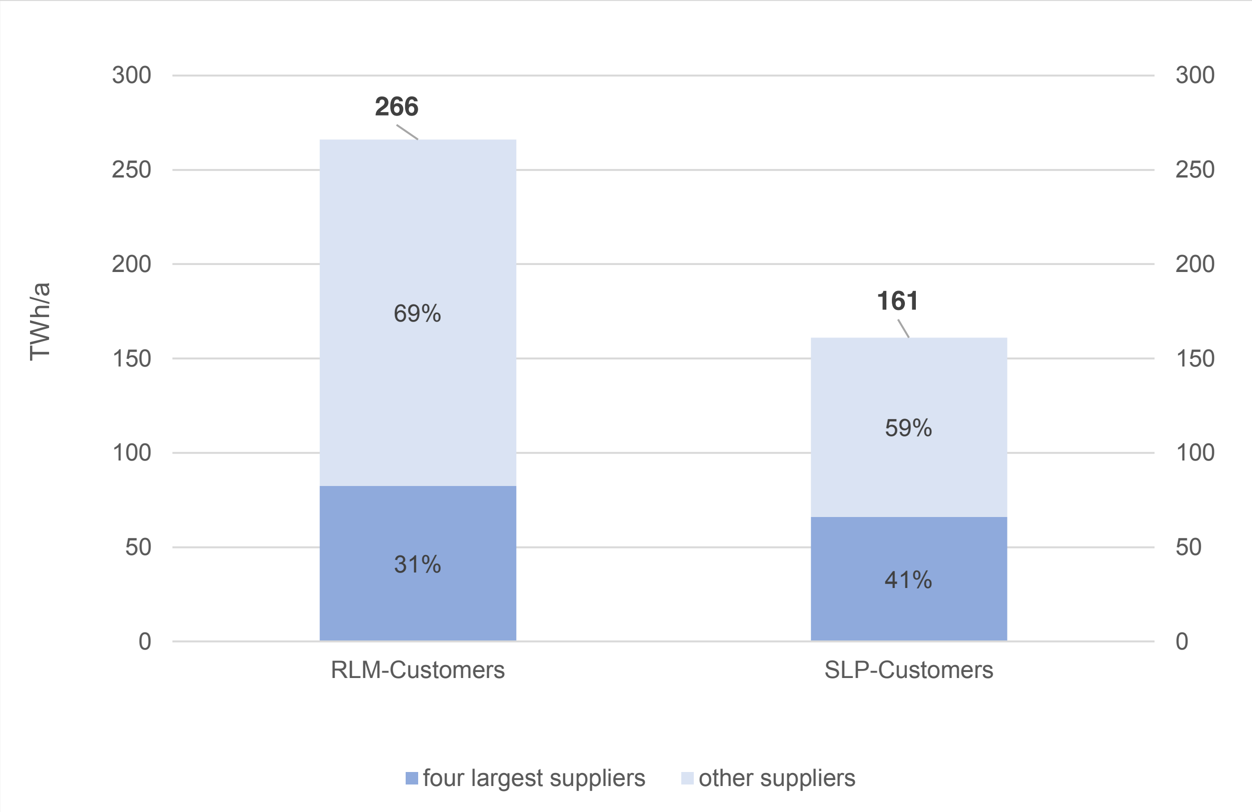
2.2.3.2 Retail electricity market

2.2.3.2.1 Market concentration and switching trends

In retail, the stakeholder structure and concentration cannot be measured as easily as on the wholesale market. Therefore, a survey has been carried out for the monitoring report.

Changes of suppliers have been rising since 2006. In 2015 around 4 Mill. customers changed their supplier. In terms of energy (TWh) the survey shows that none of the distributors is considered to have a dominating market position since the united market share of the four largest suppliers (C4 concentration measure) is below the legal boundary for any of the retail markets. Figure 19 shows that the C4-share of individually measured customers (RLM, quarter-hourly measurement) is 31% and for customers with standardized demand profiles (SLP) the C4-share is 41% (incl. electric heating – without it is 36%). (BNetzA und BKartA 2016, pp. 39–40). Whereas in the market segment of industrial customers competition is so hard that the business is partly not worthwhile any more, the segment of private customers still enables some returns (see section 5.2.2).

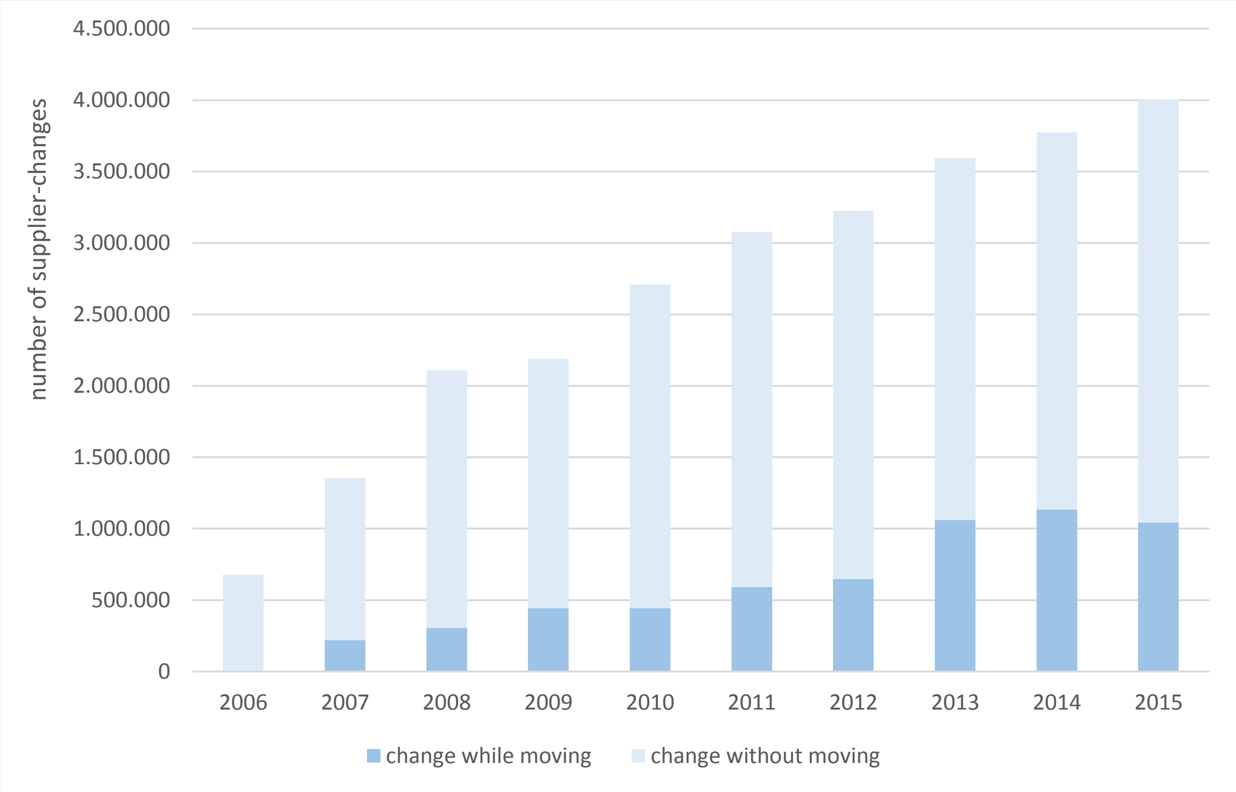
Figure 19 Share of four largest retailers in 2015



Source: IZES/own depiction; data source: BNetzA und BKartA 2016, Figure 5, p. 40

Most suppliers have a regional focus, i.e. 55% of the survey's distributer's supply only up to 10 network areas. This may be due to the fact that in Germany there are almost 900 DSOs (see section 4.3.2). This requires distributers to negotiate contracts with each one of them to supply customers in their respective areas. However, due to increased cooperation a rising share of the survey's consumers can choose from larger number of distributers: in 2015 54.8% of the consumers could choose between more than 100 distributers and 28.1% could choose between 51 and 100 distributers (corporate group affiliations not taken into account) (BNetzA und BKartA 2016, pp. 184–185).

Figure 20 Number of households changing the electricity supplier



Source: IZES/own depiction; data source: BNetzA und BKartA 2016, Figure 92, p. 193

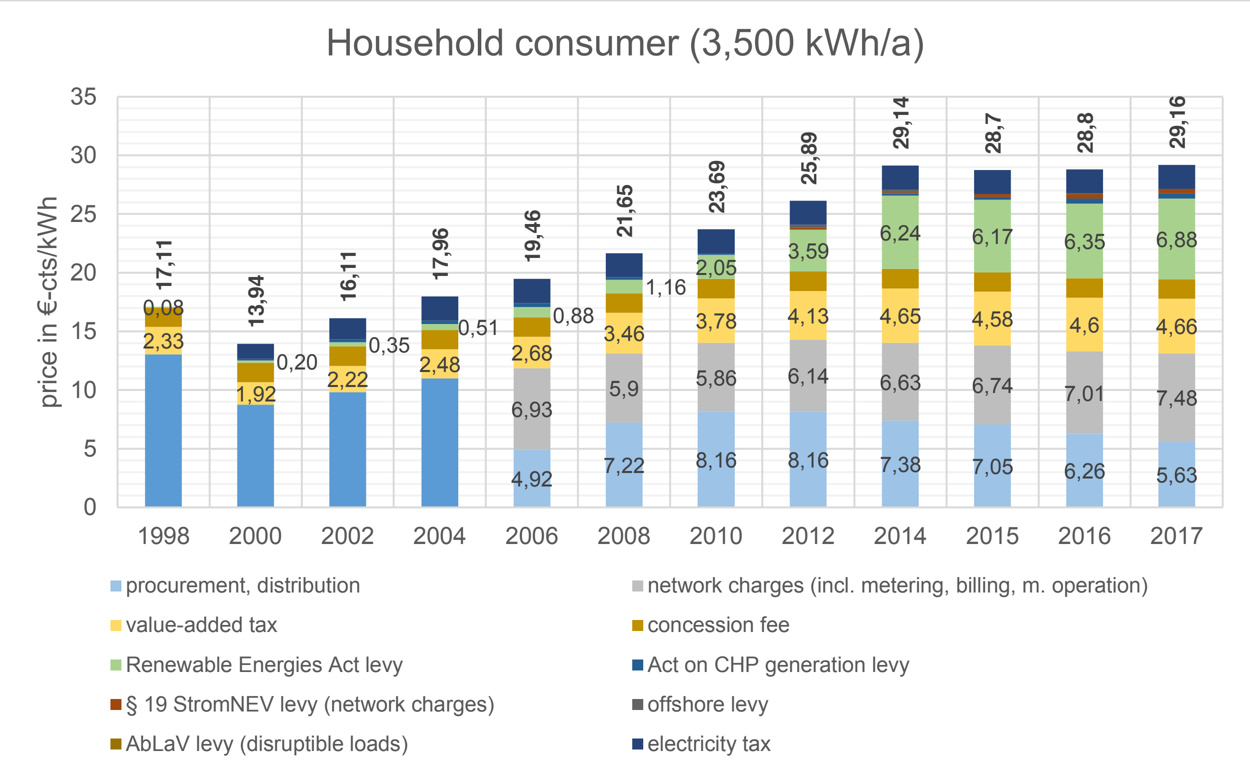
Taken together, it shows that liberalization in retail depends, in part, on the consumers' willingness to make use of the new possibilities to change distributers. The survey shows that private households take far less advantage of the new opportunities than commercial customers. 75% of the survey's household electricity customers are still supplied by their regional default electricity distributers and 32.1% even stay with the default contract even though this is usually the most expensive form of electricity supply (BNetzA und BKartA 2016, p. 25). Despite of this, the number of households changing their distributer has been steadily rising since 2006 – usually when they move (see Figure 20). Furthermore, households with higher electricity consumption change their distributer more often whereas the ones who stay with the default contract usually have lower consumption rates (BNetzA und BKartA 2016, pp. 193–194). In general, non-household electricity consumers do change their distributers much more often or re-negotiate their contract. Only less than 1% of non-household consumers with individually measured power supply (quarter-hourly measurement) the survey are supplied by their default contract. Measured in terms of energy consumption, each year since

2006 costumers representing a share of 10-12% of the supplied electricity consumption in the survey have been changing their electricity distributer (BNetzA und BKartA 2016, p. 191, Graph 90).

2.2.3.2.2 Electricity rate trends

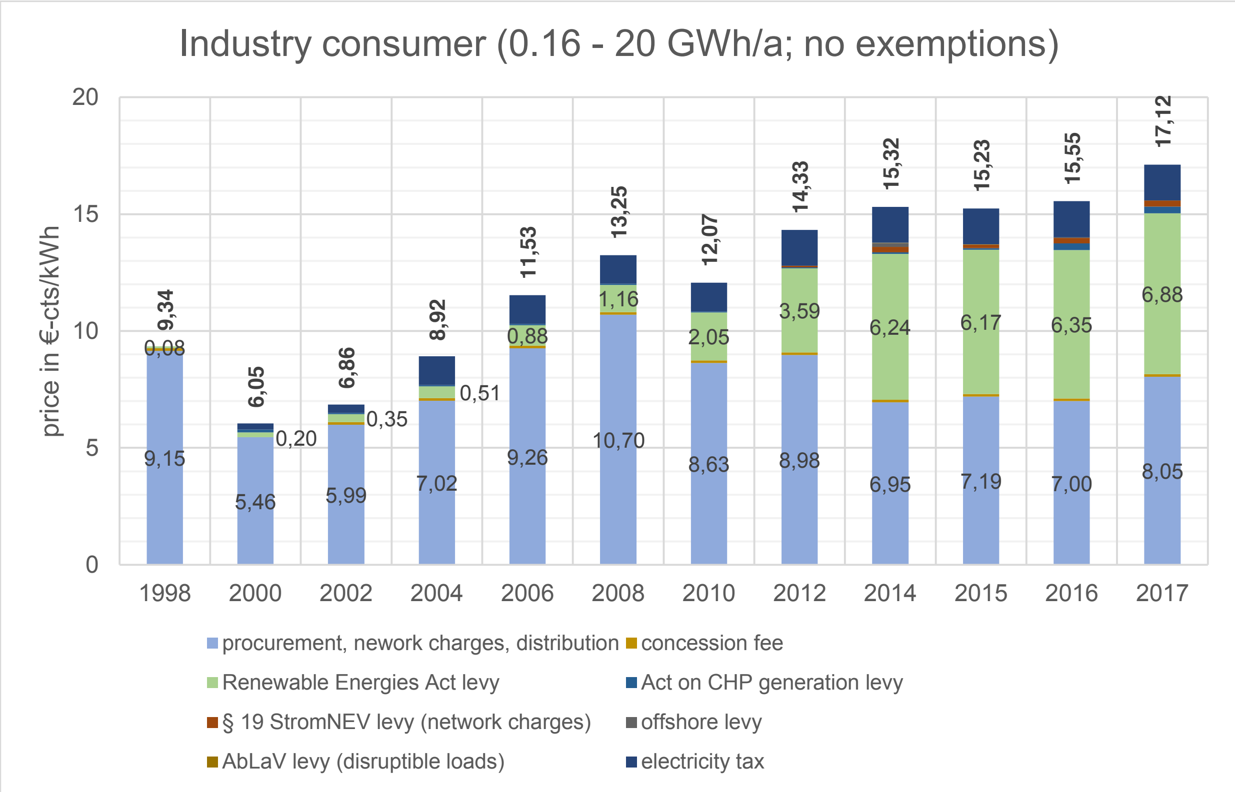
Electricity prices for households and alike first have been falling after liberalization in 1998. Then they started to rise continuously. This is mainly due to a number of surcharges levied on the rates and will be laid in more detail in sections 6.1.2 and 6.2.2 as well as section 6.3.2. Margins, however, have been decreasing in recent years due to competition as was mentioned earlier.

Figure 21 Average electricity prices and price components for household consumers



Source: IZES/own depiction, data source: BDEW, Figure 34, p. 29

Figure 22 Average electricity prices and price components for industry consumers (incl. electrictiy tax)



Source: IZES/own depiction, data source: BDEW, Figure 37, p. 29

2.2.4 Energy transition strategy: political targets and market design reform

2.2.4.1 The beginning of the energy transition

The idea of an energy transition goes already back to the 1980's. It was then more driven by the fear of resource scarcity (in particular "running out of oil") but also by the risks from the use of nuclear energy. Other goals that are often attributed to the energy transition include the reduction of import dependency and stakeholder issues often denoted as energy "democracy" (Öko-Institut 2017). During the 1980's the issue of climate policy also gains attention. Since then, a number of short- to medium-term strategies, programs and instruments have been developed that deal mainly with two lines: climate policy on the one hand and nuclear policy on the other. In terms of climate policy a first national carbon dioxide abatement target was set in 1990 and further targets (national ones as well as Koyoto commitments) where taken on later with national programs specifying sectoral targets and measures (for overviews: Fabra et al. 2015, p. 48; SRU 2008, chapter 3).

The other main issue of the energy transition was the use of nuclear energy and the first version of the nuclear phase-out ("nuclear consensus") was negotiated in 2000/2002 with the last reactor set to go offline by 2022. In 2010 (under a different Government) the phase out was prolonged by 8-14 years (for details see section 5.2.2). After the nuclear catastrophe in Fukushima, Japan, the old phase-out-decision was, in essence, reinstalled in 2011. (Matschoss 2013, p. 3).

The (first version of the) "energy concept" of 2010 stands in a tradition of government strategy paper but it marks a first coherent strategy that includes long-term goals, reaching to 2050, for all sectors (laid out below) and at the same time includes the nuclear phase out decision. The 2010 energy concept still included the prolonged phase-out. With the inclusion of the reinstalled 2011-version the energy concept became known as the *Energiewende*. For the first time it describes a strategic plan for an overall transition to a low carbon energy system based on renewable energy and energy efficiency in a government document.

2.2.4.2 Relevant government strategy papers

Since the publication of the energy concept a number of further strategy documents have been published. Some deal with the achievement of intermediate targets (2020 emission reduction targets) other spell out certain aspects of the energy transition in more detail, for instance market design. The most important strategy documents are listed below:

- *Energy Concept* (2010/2011): represents the first long-term strategy until 2050
    - Nuclear phase-out until 2022
    - Long-term targets for 2050 and (partly) pathways (with intermediate targets) for
        - GHG reduction
        - RE shares for electricity and energy end-use
        - primary energy reduction
        - electricity consumption reduction and energy requirements in building
    - Annual end-use productivity target
- *Action Program Climate Protection 2020* (2014): describes measures in all sectors (energy and beyond) to reach the German GHG-target of -40% until 2020 (wrt 1990) (BMUB 2014).
- *Electricity market reform process* (2014-2016): see section 4.1.2.1
- *Climate Protection Plan 2050* (2016): Long-term strategy paper based on a stakeholder process to reach Paris agreement (INDC). (BMUB 14.11.16)

2.2.4.3 An energy transition based on variable renewable energies (VRE) and energy efficiency

Solar photovoltaics (PV) and onshore wind have made the largest improvements in terms of cost reductions and are the established leading technologies. Therefore, the German energy transition will be based on variable (i.e. weather dependent) renewable energies (VRE). Furthermore, renewable energies in general have a lower energy density than fossil fuels. Variability of some of the RE has a number of implications for the rest of the energy system as will be shown later. The lower energy density, too, has implications. Above all there is a pivotal need for increased energy efficiency. (Leprich et al. 2012; SRU 2014, p. 18; Agora Energiewende 2017c, pp. 7–8). Meanwhile “efficiency first” has been introduced as a guiding principle (BMWi 2016d).

2.3 Structure of Japanese and German electricity generation systems – A direct comparison

Table 6 shows electricity generation and generation capacity for Japan and Germany for different points in time.

The most striking observation for Japan is the almost complete outage in generation from nuclear between 2010 and 2015 that was due to the Fukushima accident, leading to a decrease in generation share from 25% to 1%. This was mainly compensated firstly by gas whose generation has risen by 77 TWh, leading to a rising share in generation from 28 to 39% between 2010 and 2015. Secondly, the generation of coal and solar PV have almost equally increased by 33 and 32 TWh, respectively, during the same period. This has led to rising generation shares of 27-34% for coal and 0-4% for solar PV, respectively, in 2010-2015. Generation of biofuels and waste has been rising by roughly 12 TWh, leading to a rising share of 3-4%. In terms of fossil fuels, this development has increased the combined share of oil, coal and gas from 63-82% in the period of 2010-2015, increasing associated emissions. In terms of capacities, one can see that the increase in generation of solar PV is driven by an increase capacity (20 GW), leading to an increase in the share of capacities of 1-7% between 2010 and 2015. More than half of the capacities are combustible fuels and they have been increasing slightly in absolute terms but their share has been decreasing due to the (PV-driven) rise in overall capacity. Nuclear capacities, that had a share of 14% in 2015 had an almost equal share of dispatchable capacity (15% – when counting Nuclear, Hydro and combustible fuels towards dispatchable capacities).

In a more long-term view, since the first oil crisis, Japan has sought to reduce oil consumption through a diversification of energy sources towards coal-fired and LNG-fired power plants as well as the development of nuclear. Consequently, the share of output generated by oil-fired power plants declined by almost 60% between 1973 and 2010, while the share of nuclear and LNG-fired has risen markedly. Accordingly, the role of each power source in the power supply system has changed. Oil-fired power plants as base-load facilities have become middle-load and then peaking unites. Meanwhile, nuclear and large-scale coal-fired units have been playing the role of base-load facilities and LNG-fired units are the middle load facilities. (Iinuma 1991)

Data for Germany shows some similarities but also some striking differences. The nuclear phase-out in Germany has also led to a decrease in generation from nuclear but not as much. That is, between 2010 and 2015 generation decreased by around a third, leading to a decrease in share from 22 to 14% (-49 TWh). This has mainly been compensated by increasing generation from renewable energies that have higher shares in Germany than in Japan, more precisely by wind energy (+50 TWh), solar PV (+27 TWh) and by biofuels and waste (+17 TWh). The generation shares of solar PV are comparable (Jap: 4%, Ger: 6%) but that of wind are quite different (Jap: 1%, Ger: 14%). As there are conventional overcapacities in Germany, rising RES-capacities further depress prices on the energy only market. This has led to rising generation from conventional low marginal cost technologies in 2010-2015, namely coal (+9 TWh, equal share of 43%) and to decreasing generation from conventional high marginal cost technologies, namely gas (-30 TWh, 14-9%) in the same period. In terms of fossil fuels, the combined share of oil, coal and gas has decreased slightly from 59-53% in the period of 2010-2015. However, generation from emission-intensive coal has been rising as laid out before, increasing emissions accordingly. In general, Germany has higher generation shares from coal than Japan. In terms of capacity, one striking element in Germany is that between 2010 and 2015 41% or approx. 8 GW of nuclear capacities where formally taken out of service (the remainder is still used for generation though as laid out above), leading to a reduced share of 6% in 2015. The other striking difference is the steadily rising shares in renewable capacities since the 2000's (for wind even earlier), leading to 19% for solar PV and 20% wind, or a combined share of 39%, in 2015. Still, around half of the German capacities are based on combustible fuels. Despite an increase of 11 TWh (13%) in the period 2010-2015 their share has been decreasing from 53-49% due to the renewables-induced overall rise in capacity.

In comparison, the Fukushima accident caused a sudden drop in generation from dispatchable capacities in the baseload power segment in Japan that was compensated mainly by gas and by some coal. Over time, however, generation from solar PV had also contributed. In Germany, the decrease in nuclear generation takes the form of a phase out and is compensated by (i) overcapacities in the conventional segment and (ii) a steady increase in renewable capacities that already started the 2000's. Both countries have high generation shares from fossil fuels, pointing to the need to decarbonize the energy supply system.

Table 6 Electricity Generation and Capacity in Japan and Germany

Electricity Generating Capacity (GW)														
Japan														
	1974		1990		1995		2000		2005		2010		2015	
Nuclear	3,91	4%	31,65	16%	41,36	18%	45,25	17%	49,58	18%	48,96	17%	44,26	14%
Hydro	23,55	23%	37,83	19%	43,45	19%	46,32	18%	47,3	17%	47,74	17%	49,6	16%
Combustible fuels	76,74	74%	124,98	64%	142,15	62%	167,97	64%	177,27	64%	183,88	64%	194,86	62%
Geothermal	0,02	0%	0,27	0%	0,51	0%	0,53	0%	0,54	0%	0,54	0%	0,51	0%
Solar PV	-	-	-	-	0,04	0%	0,33	0%	1,42	1%	3,62	1%	23,34	7%
Solar Thermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	0,08	0%	1,22	0%	2,29	1%	2,75	1%
Total Capacity	104,21	100%	194,73	100%	227,65	100%	260,49	100%	277,32	100%	287,03	100%	315,32	100%
Peak Demand	-		143,72		171,13		173,07		177,7		177,75		159,07	
Germany														
	1974		1990		1995		2000		2005		2010		2015	
Nuclear	3,29	5%	22,41	0,23	22,83	20%	22,4	19%	20,38	16%	20,47	13%	12,07	6%
Hydro	4,81	7%	8,18	0,08	8,88	8%	9,49	8%	8,34	7%	11,22	7%	11,23	6%
Combustible fuels	58,09	88%	68,44	0,69	83,36	72%	80,79	68%	76,38	61%	85,82	53%	97,2	49%
Geothermal	-	-	-	-	-	-	-	-	-	-	0,01	0%	0,02	0%
Solar PV	-	-	-	-	0,02	0%	0,11	0%	1,51	1%	17,55	11%	38,23	19%
Solar Thermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	0,05	0%	1,14	1%	6,1	5%	18,43	15%	27,18	17%	39,19	20%
Total Capacity	66,2	100%	99,08	100%	116,23	100%	118,88	100%	125,03	100%	162,7	100%	198,42	100%
Peak Demand	-		73,01		83,31		80,85		・・		-		-	
Electricity Generation (TWh)														
Japan														
	1974		1990		1995(***)		2000		2005(***)		2010		2015	
Nuclear	19,70	4%	202,27	23%	291,25	26%	322,05	29%	304,76	25%	288,23	25%	9,44	1%
Hydro	84,78	18%	95,84	11%	91,22	8%	96,82	9%	69,9	6%	90,68	8%	91,19	9%
Oil	-	-	283,73	32%	220,64	20%	179,36	16%	88,3	7%	100,15	9%	90,81	9%
Coal	-	-	117,71	13%	172,78	16%	233,77	21%	259,15	21%	309,59	27%	342,72	34%
Gas (LNG)	-	-	170,64	19%	191,05	17%	253,64	23%	230,92	19%	318,61	28%	395,19	39%
Biofuel & waste	-	-	9,57	1%	19,74	2%	10,25	1%	3,22	0%	30,23	3%	41,77	4%
Geothermal	0,10	0%	1,74	0%	3,17	0%	3,35	0%	3,03	0%	2,65	0%	2,55	0%
Solar	-	-	0,00	0%	0	0%	0,35	0%	0,01	0%	3,80	0%	35,97	4%
Wind(****)	-	-	-	-	0	0%	0,11	0%	・・	・・	3,96	0%	5,29	1%
other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Production	459,08	100%	881,50	100%	1103,88	100%	1.099,67	100%	1227,32	100%	1.147,90	100%	1.014,93	100%
Self-sufficiency ratio(*)	12.9(**)		17,5		18,8		18,8		17,4		18,1		9,5	
* domestic primary energy production/total primary energy supply; ** Data is 1975														
Total production includes autoproducer's production (composition not available); * Wind data for 1995 and 2000 included in Solar														
Germany														
	1974		1990		1995		2000		2005(**)		2010		2015	
Nuclear	14,46	4%	152,47	28%	153,09	29%	169,61	29%	163,06	25%	140,56	22%	91,79	14%
Hydro	19,21	5%	19,79	4%	21,78	4%	25,96	5%	19,22	3%	27,35	4%	24,9	4%
Oil	-	-	10,4	2%	8,98	2%	4,79	1%	4,31	1%	8,74	1%	5,65	1%
Coal	-	-	321,64	58%	296,78	56%	304,16	53%	287,78	44%	273,46	43%	281,96	43%
Gas (LNG)	-	-	40,46	7%	43,17	8%	52,5	9%	52,31	8%	90,35	14%	60,77	9%
Biofuel & waste	-	-	5,19	1%	7,3	1%	10,12	2%	13,76	2%	40,66	6%	57,73	9%
Geothermal	-	-	-	-	-	-	-	-	-	-	0,03	0%	0,13	0%
Solar	-	-	0	0%	1,48	0%	0,06	0%	28,51	4%	11,73	2%	38,43	6%
Wind	-	-	0,07	0%	・・	・・	9,35	2%	・・	・・	37,79	6%	87,98	14%
other	-	-	-	-	-	-	-	-	-	-	2,32	0%	2,16	0%
Total Production	392,14	100%	550,02	100%	532,57	100%	576,54	100%	660,57	100%	632,98	100%	651,5	100%
Export	10,6		30,7		34,91		42,1		61,43		57,9		74.3(*)	
Import	17,7		31,7		39,74		45,1		56,86		43		40.4(*)	
* Data is 2014; **Total production includes autoproducer's production (composition not available)														

Source: IEA 2003, 2005, 2008, 2016

3 Dispatching capacity: market segments and players

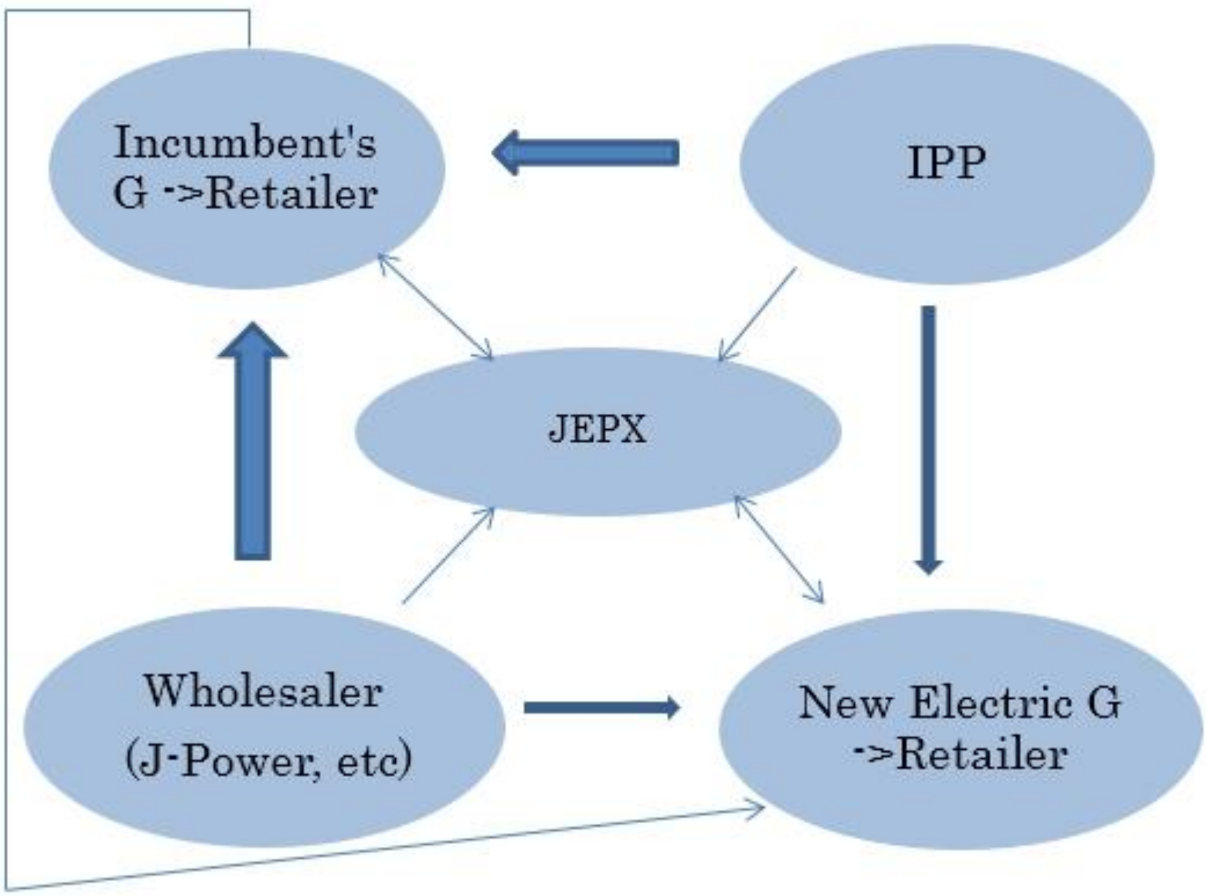
3.1 Efficient dispatch

3.1.1 Japan

3.1.1.1 Structure of wholesale market: market segments and volumes

Wholesale trade in Japan is comprised of bilateral trades and trading at Japan Electric Power Exchange (JEPX). As Figure 23 shows, there are various transactions among participants in the wholesale trade. Among other things, the share of self-supply from incumbents' generating plants to their retail supplier is substantial. In 2014, in the case of formerly vertically integrated incumbents, about 77.3% of supply source came from incumbents' own generating power plants. Bilateral trade with other players accounted for 21.3% while trading at JEPX was only 1.0%.

Figure 23 Current Structure of Wholesale Trade in Japan

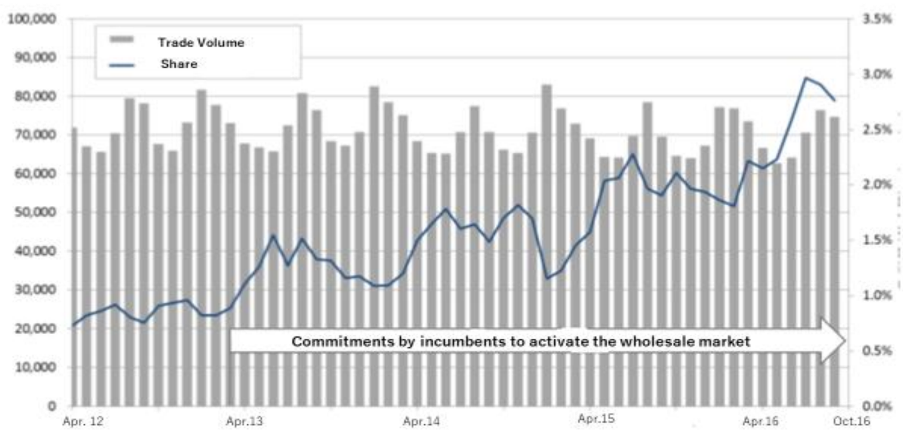


Source: EGMSC 2017b, p. 36

JEPX was established in November 2003 to provide a privately operated, voluntary wholesale exchange designed to stimulate transactions on the exchange contributing to the strengthening of utilities' risk management capabilities by, for example, offering enhanced instruments for selling and sourcing electricity and encouraging the formation of index prices to assist assessment of investment risk. JEPX commenced trading in April 2005 and currently provides a marketplace for the following electricity transactions:

- Spot market: trading in 30 minutes increments of electricity for next-day delivery.
- Intra-day market: A market for correcting unexpected misalignments between supply and demand occurring between a spot market transaction and delivery.
- Forward market: Trading in electricity for delivery over the course of a specified future period. Products are created by packaging together specific periods and times, such as monthly 24-hours products or weekly daytime products.
- Distributed and Green Market: Established in 2012 when demand and supply was very tight due to aftermath of the giant earthquake in 2011. Self-generators and cogeneration with capacity of less than 1000kW can sell their excess output to this market. They can set the price, volume and other conditions voluntarily.

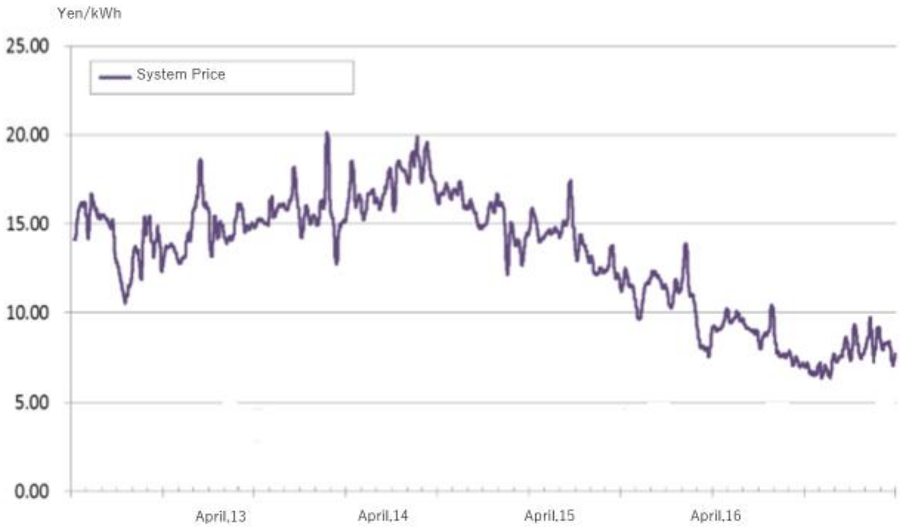
Figure 24 Contracted Trade Volume at JEPX (April 2012 - September 2016)



Note: The vertical axis on the left shows total electrical consumption in GWh (grey bars); the vertical axis on the right shows the share of contracted trade volume at JEPX in total electrical consumption (blue line).

Source: EGMSC 2017b, p. 36

Figure 25 System price at JEPX



Source: EGMSC 2017c, p.40

Liquidity has been, however, quite low. This is particularly true if we compare with other countries. Table 7 shows that trade volumes in UK, France and Scandinavia are much higher. Table 8 shows trade volumes in JEPX's markets. It is notable that the share of forward transaction for risk hedge is also quite low.

The share of spot trading at JEPX in Japan's total electricity demand was only 2.9% in the period of July 2016 to September 2016 though it is increasing gradually (Figure 24). A prime reason for low liquidity is dominance of incumbents. That is formerly vertically integrated electric utilities own most of generating plants. The incumbents supply their generating power mostly to their own retail companies and firm back-up to retail suppliers through bilateral trades and then selling remaining excess power to JEPX.

Price at JEPX is determined by the system marginal price. Figure 25 shows the trend of system prices over the years. Since the winter peak recorded in 2013, it was on downward trend. Yet, they have been rising since June 2016. In particular, a bidding price to buy by new entrants is soaring and the system price is beginning to exceed a bidding price to sell by incumbents.

Given above-mentioned status of trading at JEPX, measures to improve the function of price signal and transparency are being introduced. Gross bidding is one of them. From April 2017, the incumbents are supposed to make a selling bid of the portion of trading between the generating section and the retail section of incumbents to JEPX. Specifically, it is expected that the incumbents make a selling bid of 10% of internal trading within one year and 20% to ~30% within a few years. Other measures to activate the wholesale market are also being introduced (Table 8).

Table 7 Share of Contracted Volume through the Spot Market

Nord Pool (2013)	Germany (2013)	Japan (2015)	UK (2013)
86.2%	50.1%	1.6%	50.7%%

Note: The share for Japan was derived using data from JEPX and METI's Electric Power Survey Statistics

Source: EGMSC 2017c, p. 38

Table 8 Trade Volume in JEPX's market

Item	Spot (day-ahead)	Intraday	forward
Volumes	10.3 TWh	0.57 TWh	0.06 TWh
Ratio of total electricity sale	2.5%	0.1%	0.01%
Measures to activate	Bid-in of excess power source Introduction of gross bidding in 2017	Bid-in of excess power source	Establishing base-load power source market in 2019

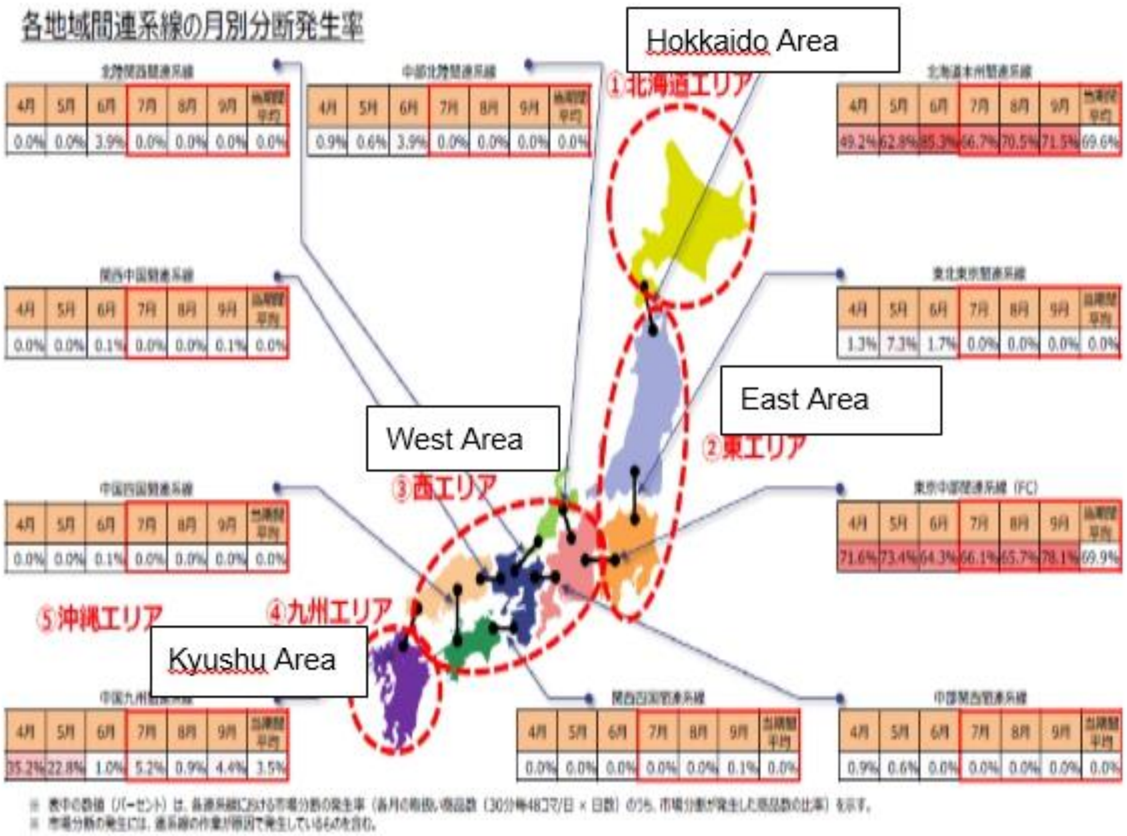
Source: ANRE 2017b

3.1.1.2 Market areas and market split

The power system in Japan except Okinawa is interconnected by transmission lines. The configuration of power system is not the mesh type but the comb-like type. Unlike Germany or other countries such as the US which are composed of many players and unbundled systems, Japanese system did not assume large amount of trading between electric utilities. It can be said that the electricity supply system was basically autonomous in each service area of the vertically integrated electric utility. In other words, each electric utility was responsible for maintaining adequate supply capacity and reliability in each monopolized area. The interregional connector between electric utilities was simply to complement utilities' responsibility in each supply area. The role of interconnector between electric utilities was not for active trading between electric utilities. Therefore, the capacity of interconnector had been very limited. As a result, we have come to often see market splitting because of lack of interconnector accommodating active trading.

According to analysis by the government, frequency of market splitting caused by constraint of interconnectors is very high in some areas (Figure 26). In particular, the constraint between Hokkaido and Honshu, between Tohoku and Tokyo, between Tokyo and Chubu (Frequency Converter Station) and between Chugoku and Kyushu is conspicuous.

Figure 26 Monthly market-spitting by interconnector in Japan



Source: EGMSC 2017c, p. 33

Table 9 Market splitting in regions in Japan

Wholesale Market Region	frequency			
	all hours	daytime	nightime	HHI
Hokkaido	74%	64%	88%	8,917
West-Kyushu	58%	55%	61%	1,664
East (Tohoku-Tokyo)	45%	38%	55%	4,643
East-West-Kyushu	27%	24%	30%	1,642
Hokkaido-East	19%	26%	9%	3,951
Kyushu	9%	11%	6%	6,036
All over Japan	6%	9%	3%	1,531
West(Chubu-Hokuriku-Kansai-Chugoku-Shikoku)	6%	9%	2%	2,131
East-West	2%	1%	3%	1,933
Hokkaido-East-West	1%	1%	1%	1,788

Source: EGMSC 2017c, p. 34

Where wholesale trade is constrained by lack of interconnectors, market is split. Split market is not competitive but very concentrated represented by presence of incumbents. Table 9 shows frequency of market split in the wholesale market region and the degree of market concentration by HHI. In the case of Hokkaido region, for instance, in 74% of all hours, 64% of day and 88% of nigh-time market is isolated from other regions due to constraint of the interconnector. HHI is quite high as the incumbent utility is dominant.

3.1.1.3 Other aspects: merit-order and generation costs

Figure 27 shows a typical load curve in Japan. Nuclear, coal, conventional hydro and geothermal power plants play the role of base load plants. Middle part of load is met by gas while oil and pumped hydro power plants are peaking plants.

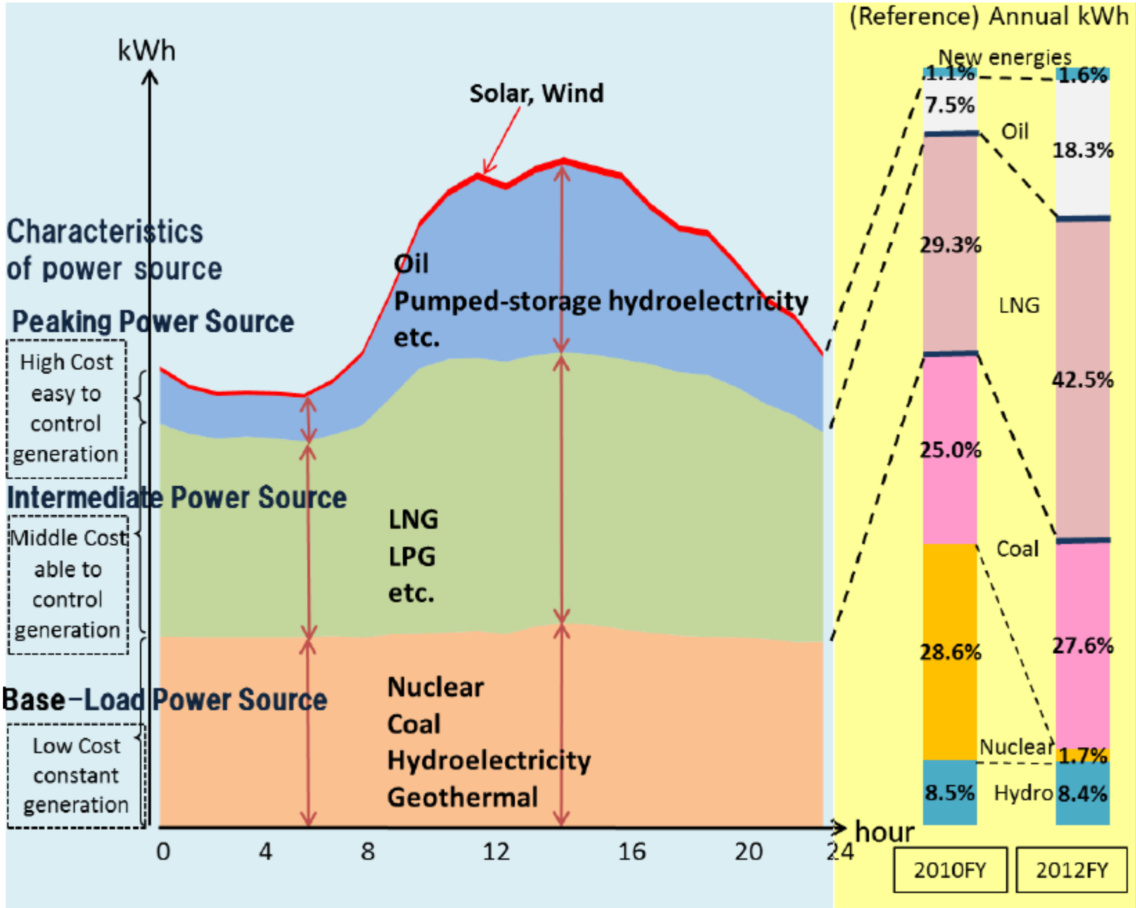
Electricity demand in each area had been basically met by generating capacity owned by each electric utility based on the merit order system. The role of each generating source has been traditionally determined by the generating cost and attributes of each generating technology.

Table 10 shows estimates of levelized costs of electricity generation made by the government committee in 2015. The methodology adopted by the government is basically same as those used by OECD and the US Energy Information Administration.

Among technologies, nuclear generation cost is lowest both in 2014 and 2030. In deriving the nuclear cost, various costs including the actual Fukushima's costs of compensation and decommissioning were taken into consideration. Yet social costs of nuclear power entail uncertainty. At the time of estimation in 2015, the cost of compensation and decommissioning was around ¥9 trillion or €67 billion. However, it is now estimated to be around ¥21 trillion or €174 billion. Coal-fired generation cost took into account social cost like CO_2 cost. In deriving the estimate in 2030, CO_2 price was assumed to be $35 per ton.

Given increasing renewable energy generation, the way of harnessing renewables in power system operation will be one of challenging issues. Duck curve is a symbolic example though we have not reached that situation yet. In deriving the cost of renewable energies, various integration cost was estimated as well. The integration cost is externality of increasing renewable energies, in particular VRE.

Figure 27 Load Curve and Generation Mix



Source: METI 2014

Table 10 Generation cost by technology

				(Yen/kWh)
	2014	2030	Capacity Factor(%)	Operating Years
Nuclear	10.1～	10.3～	70	40
Coal	12.3	12.9	70	40
LNG	13.7	13.4	70	40
Oil	30.6˜43.4	28.9～41.7	10˜30	40
Onshore wind	21.6	13.6～21.5	20(2014),20˜23(2030)	20
Offshore wind	−	30.3～34.7	30	20
Conventional hydro	11	11	45	45
Geothermal	16.9	16.8	83	40
PV (utility scale)	24.2	12.7～15.6	14	20(2014),30(2030)
PV (roof top)	29.4	12.5～16.4	12	20(2014),30(2030)

Source: ANRE 2015a

The measure to deal with excess supply is the rule to curtail outputs by generating technologies. Priority dispatching rule is stipulation of the conditions and orders for restricting output of generating power sources responding to changes in electricity demand to balance supply and demand. After 2020 when electricity supply system is legally unbundled, transmission and supply companies will be responsible for balancing supply and demand. In the transitory stage toward 2020, the transmission and supply department of each electric utility is responsible for power system operation. For more details see section 4.3.1.6.

Latest rule governing dispatching can be characterized such that so-called long-term fixed generating power sources composed of nuclear, hydro and geothermal power should be the last in terms of restriction of output (see section 4.3.1.6).

The concept of base-load is disappearing in Europe as the share of renewable energies increase. In Japan, however, it will remain intact for the foreseeable future in light of the government plan to establish the base-load market.

3.1.2 Germany

3.1.2.1 Structure of wholesale market: market segments and volumes

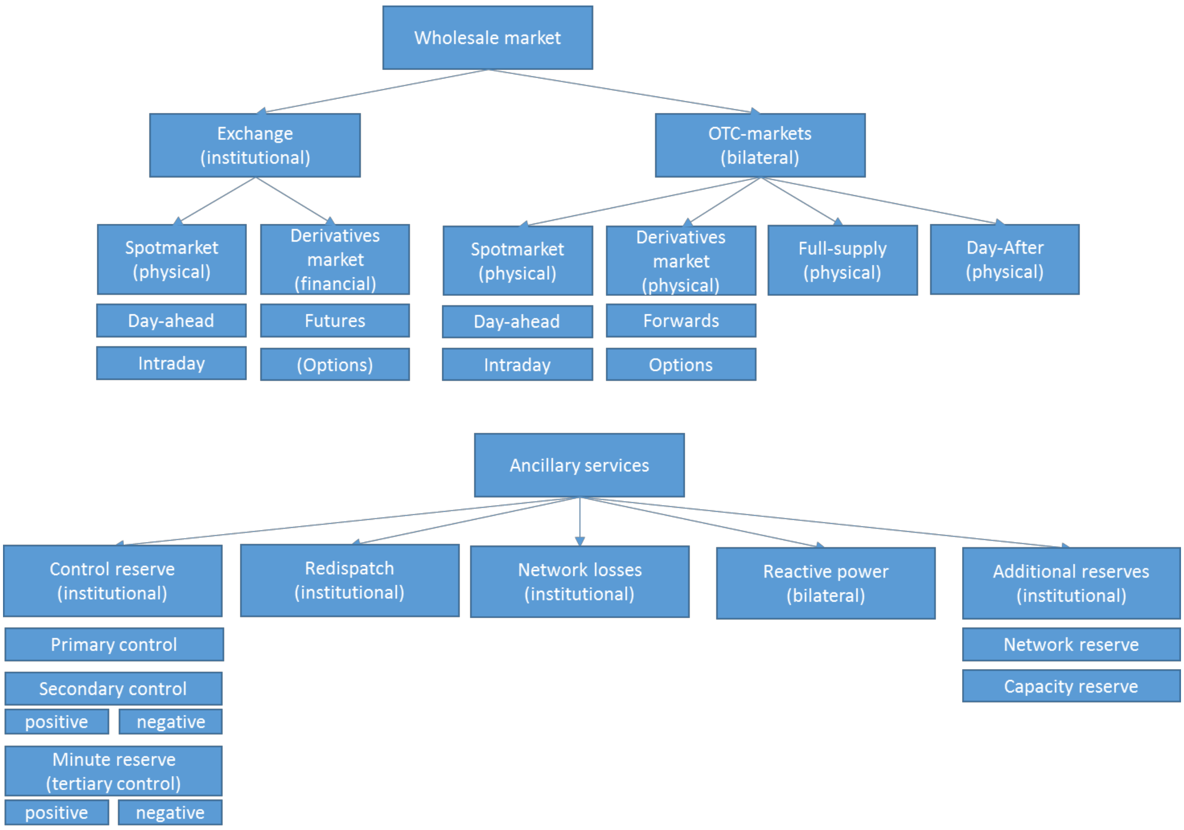
In theory the most efficient dispatch of electric generation is given by the merit order. The merit order ranks available generators by ascending short-run marginal costs of production. Marginal costs contain fuel costs, variable operation and maintenance costs and, if internalized, costs for CO_2-emissions.[1]

Trading electricity based on marginal costs introduced wholesale markets and added a new stage in the value chain (Grashof et al. 2015, p. 20). As there is only energy traded in the different market segments (no capacity credits) it is also called energy-only-market (EOM). In addition, electricity network operators procure capacities for ancillary services, in particular for the control reserve. An overview of the segments of wholesale and ancillary service markets is shown in Figure 28. The wholesale market is by orders of magnitude larger. In 2015 the day-ahead trade at EPEX SPOT had a volume of around 264 TWh and the intraday of around 38 TWh. The derivative market's volume at EEX was around 937 TWh. The market for secondary control reserve in 2015 on the other hand only had a volume of around 1.4 TWh (positive control) and 1.1 TWh (negative control), respectively. For tertiary control volumes where around 221 GWh (positive control) and 119 GWh (negative control), respectively. (BNetzA und BKartA 2016, pp. 24, 130, 134, 165)

[1] Marginal costs can differ strongly dependent upon the load-range in which generation units operate, especially if cold starts are required.

As mentioned above (see section 2.2.2), Germany chose an exchange-model for the market organization. This enables completely deregulated and decentralized wholesale and retail markets. Market participants can choose freely how and where they trade electricity. The idea is to trade irrespective of physical flows and network restrictions within a market area in order to enhance competitiveness ("illusion of a copper plate"). This way, e.g. capacity withholding to influence market prices shall be prevented. After the end of financial trades ("gate closure") the TSO needs to manage the resulting physical flows ("real time" or "realization"). In the case of strong regional disparities between supply and demand that may result in network congestion, the TSO may order single capacities to deviate from their original production decision, or to "redispatch". In Germany, this typically happens in situations of strong winds in the North where more electricity is sold to the south than can be transported due to internal network congestions. Then capacities in the North ("before" the congestion point) are decreased and capacities in the South ("behind" the congestion point) are increased (BNetzA 2016b).

Figure 28 Market segments of the electricity wholesale market



Source: IZES/own depiction

In terms of time pattern the wholesale market distinguishes between forward or future markets on the one hand and the spot market on the other. The futures markets mainly deal with financial fulfilment. In OTC trading physical fulfilment is common. The spot market can be distinguished between day-ahead and intraday market and has binding physical fulfilment (SRU 2014, pp. 30-3, Fig. 2-2; see also Fig. below).

At first there was a pure bilateral trade (OTC) but soon electricity exchanges developed (SRU 2014, pp. 30–33). The day-ahead-price of the EPEX SPOT exchange in Paris[2] serves as reference price for all electricity markets in Germany. For this purpose the EPEX SPOT organizes the day-ahead market as a uniform price auction (Ockenfels et al. 2008, p. 24). Additionally this pricing method is comparatively transparent and simple, which keeps transactions costs for market participants low (Ockenfels et al. 2008, p. 17).

Market participants have to maintain balance groups, were forecasted or planned demand and generation are to be kept in balance. The market participants as balance responsible parties[3] (BRPs) send schedules to the responsible transmission network operators (TSOs)[4] which verify system balance for their balance areas incorporating all balance groups. The remaining imbalance between demand and generation is evened out by a control reserve ("Regelleistungsreserve", "Regelenergie"). Control reserve is procured by and provided for by the TSOs in three different types that need to be available within different time periods: primary reserve needs to be available within 30 seconds, secondary reserve within 5 minutes and tertiary/minute control within 15 minutes. The TSOs procure the control reserves via joint tenders and operation of the control reserve is coordinated for the whole German market area. (50Hertz et al. 2017e).

To minimize need of control reserve in the first place incentives are provided to BRPs to use short term trading in order to balance out possible imbalances from the commitments. At the EPEX SPOT exchange intraday market continuous trading of short term contracts is possible up to 30 minutes before delivery. OTC trading is even possible until up to 15 minutes before fulfilment. For a better integration of variable renewable sources (Wind and PV) electricity at the intraday market can be traded for quarterly hours. To enforce this, the fees for using the control reserve are calculated in a manner that they are above hourly intraday spot market prices anytime, independent of the real

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2 The EPEX SPOT exchange in Paris originated from a merger between the Powernext SA in Paris (France) and the EEX AG in Leipzig (Germany). It took over the German spot market, while a derivatives market for electricity still remains at the EEX in Leipzig.

3 Term used by the European Network of Transmission System European Operators for Electricity (ENTSO-E 2012)

4 In Germany there are four balancing areas managed by 50Hertz Transmission GmbH, Amprion GmbH, TransnetBW GmbH, TenneT TSO GmbH

price for the control reserve. In the case control reserve is used to 80% of its maximum an additional penalty is charged (50Hertz et al. 2017e). However, some possibilities for arbitrage remain (Peek und Diels 2016, pp. 176, 181).

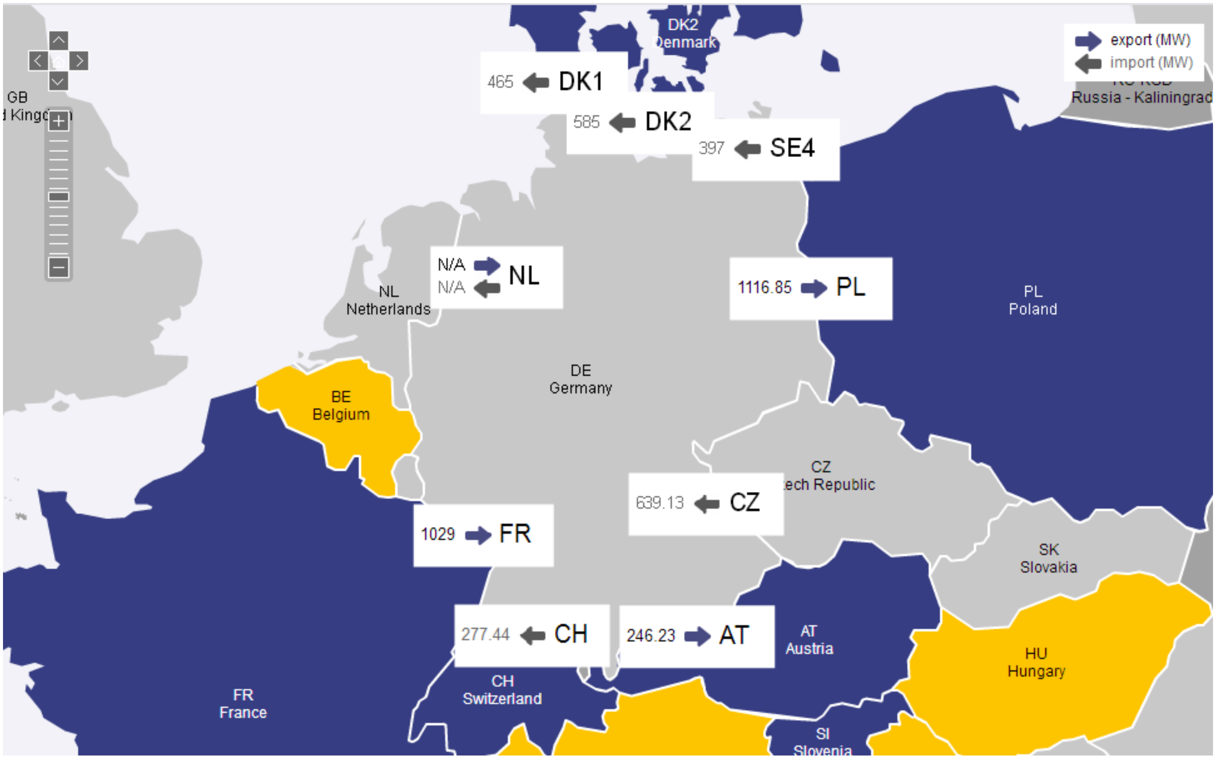
The stronger focus on short term trade is a recent development over the last years that mirrors the increasing need to better integrate wind and PV as mentioned above. Quarterly hour products for the day-ahead market have been introduced in December 2014. Since July 2015 these contracts may be traded until 30 minutes before real time. Rising trade volumes are also an indicator for the need of more short-term integration. The above-mentioned trade volume of 38 TWh for the intraday market represents a growth of 46% with respect to the previous year. (BNetzA und BKartA 2016, pp. 164–165) With the day-ahead price as reference different derivatives markets are possible and established. In general standardized futures for hedging are traded at the energy exchanges covering the German market area. OTC hedges are carried out by using forwards.

3.1.2.2 Market areas and market split

As it was described in sections 2.2.2.3 and 4.1.2.2 Germany is part of a larger effort to integrate the European electricity markets. This requires common market rules ("software") as well as sufficient transmission capacity ("hardware"). Since Germany is located in the center of Europe, it is serving a hub-function. Figure 29 shows German transmission lines with its neighbors. Nevertheless, transmission capacity with neighboring countries is scarce and therefore it is part of the "software" to optimize the management of these transmission capacities.

Austria and Germany, however, introduced a common market zone in 2001 so that spot market prices are the same (same 'copper plate' – see section 3.1.2.1). This common price zone will now be split again as of October 2018. That is, there will be price differentials, in particular in times of the above-mentioned situations of redispatch with high wind energy production in Northern Germany. They have led to high exports to Austria and circular flows of electricity via Poland and the Czech Republic. (Platts 2015; BMWi 2017a). The measure restricts the exports to Austria but actually points to (i) a lack of transmission capacity *within* Germany and (ii) a need to see the issue in conjunction with other issues such as system flexibility and must-run capacities (see section 4.1.2.2).

Figure 29 German cross-border flows with neighboring countries



Source: ENTSO-E 2017a

3.1.2.3 Efficient dispatch, market segments and stakeholder

In theory, the system of the energy-only market based on merit-order dispatch does not discriminate between market segments or stakeholders. Supply capacities based on various fuels, combined heat and power (CHP) and renewable energies may take part in the merit-order market.

By design, however, the merit-order market utilizes capital-intensive capacities with low marginal costs first Resulting in the following merit-order: Nuclear has the lowest marginal costs, followed by lignite as the second and hard coal as the third. This is followed by gas capacities and oil was the last in the merit order. Furthermore, it depends on specific situations (place in the merit-order, electricity demand and resulting price etc.) whether or not a capacity in question earns a remuneration above marginal costs and is therefore able to serve its debt. Therefore, capacities that have low marginal cost or whose debt is already served – or both – do have an advantage in the merit-order market (this advantage is sometimes referred to as the “golden end” of the investment). It was mainly the incumbents (the so-called “big four” or their legal successors, respectively) who could benefit from that due to their large capacities from pre-liberalization times.

In control reserve markets the main reason for the lack of new market participants & technologies are administrative barriers, i.e. pre-qualification procedures. First steps have now been made to open the pre-qualification of the control reserves. Batteries are eligible for the primary reserve and first batteries have been pre-qualified. Furthermore, there is a test phase for wind energy in the tertiary reserve and first wind capacities have been pre-qualified. (50Hertz et al. 2017e; Gust 2017a; IWR 2015). Also, some energy-intensive industries have been pre-qualified as DSM-capacities via a dedicated ordinance. Here, pooling has been introduced in order to allow smaller units (~500kW) to take part in the auctions. (AbLaV)

3.2 Clean Dispatch

3.2.1 Japan

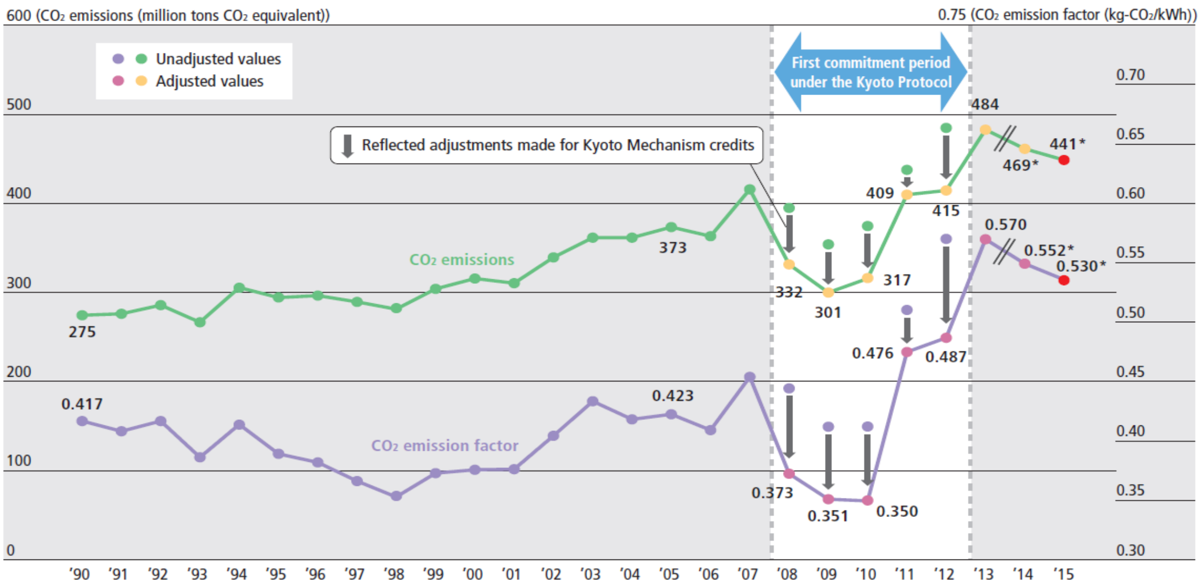
3.2.1.1 Voluntary Efforts by the Electric Utilities to Tackle with Climate Changes

The electric utilities in Japan have been combating environmental problems voluntarily. Japan does not have the national emission trading scheme though a few municipalities such as Tokyo and Kyoto have their own locally. The carbon tax has been introduced in 2012. Yet the carbon price is ¥289 or €2,39 per tonne of CO_2 so that its effect seems to be limited. It can be said that clean dispatching in Japan has been basically relying on voluntary commitments by electric utilities rather than on mandatory measures such as carbon pricing.

“Commitment to a Low Carbon Society” formulated by the Japan Business Federation (Keidanren) commits the Japanese business community to playing an instrumental role in the drive to reduce global GHG emissions by setting targets by 2030. 57 industries including the electric utility industry have set targets. The target in 2030 set by the electric utilities is 0.37kg-CO_2/kWh in 2030. This target corresponds to the electricity generation mix depicted in the Long-term Energy Supply Outlook shown in Figure 17. Therefore, the target was not necessarily set by CO_2 reduction goal promised internationally by the Government of Japan.

Electric utilities sought to achieve their CO_2 emission reduction targets through such efforts as utilization of nuclear power generation, development and dissemination of renewable energy sources and enhancement of thermal power efficiency. After the Great East Japan Earthquake in 2011, however, the prolonged shutdown of nuclear power plants and resulting increase in thermal power’s share of total power generation from around 60% to 80%-90% brought about higher CO_2 intensity from 0.350kg-CO_2/kWh in 2010 to 0.570kg-CO_2/kWh in 2013 (Figure 30). It will require a reduction of 35% from the 2013 level to achieve the target in 2030.

Figure 30 CO_2 Emission by the Electric Utilities



Source: JEPIC, 2017, p. 27

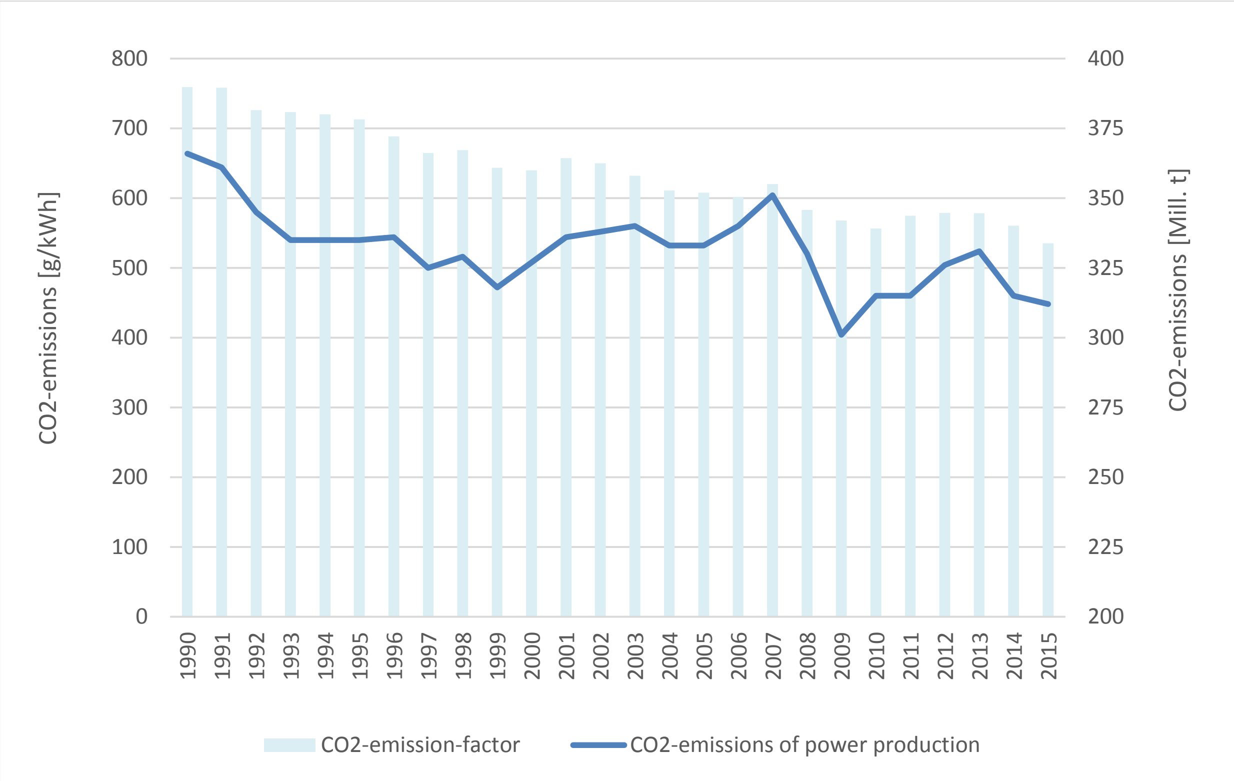
Whether it is possible to achieve this target would depend on uncertain factors such as the role of nuclear power generation and renewable energies in the future electricity generation mix, electricity market reforms and improvements of energy efficiency.

3.2.2 Germany

The term “clean dispatch” denotes that those capacities should be used that are in line with the environmental goals of the German *Energiewende*, namely with emission reductions. Other goals go beyond “clean” but some may be more directly linked to energy carriers (supply security) others less (stakeholder variety, decentralization). A number of measures have been taken to pursue these goals (or even to pursue the same goal).

The following description is restricted to generation. Storage technologies that are active in the wholesale market (mainly pumped storage) do not have a fixed place in the merit-order. This is due to the fact that part of their business model consists of utilizing price differences over the day (peak skimming). That is, they demand and store energy at low prices and supply energy at higher prices. Their marginal costs, however, are determined, in part, by their relative efficiency. That, in turn, depends on the price spread between electricity price of storage and price of roll out. DSM is used in ancillary service markets rather than wholesale. Furthermore, the mechanism works via raising the flexibility of demand rather than via the merit-order.

Figure 31 Development of the specific CO_2-emissions of the German power generation mix 1990 - 2015



Source: IZES/own depiction; data source: Icha 2016, p. 7

3.2.2.1 Emission reduction and emissions trade

Germany is part of the European Emissions Trading Scheme (EU ETS) that was introduced in 2005. From the perspective of economic theory, emissions trade is the best option to integrate CO_2-reduction goals into the dispatch-decision. The inclusion of the CO_2-Price adds an additional factor to the marginal costs that weighs capacities according to their CO_2-intensity without changing the merit-order system itself. Whether or not the switch of the merit-order will succeed depends on the height of the price which, in turn, depends on the reduction target. However, current CO_2 prices of €4-5 or ¥483-604 (Graichen et al. 2017, p. 32; EEX 2017a) are much too low for the necessary switch of the merit-order. To reach first switches in the merit-order between new gas and old coal capacities, CO_2-prices of above €12-25 or ¥1,444-3,008 would be necessary. First switches between single, inefficient lignite and new gas capacities would occur at CO_2-prices above €32-50 or ¥3,850-6,015 (UBA 2016, p. 25, with fuel prices as of February 2016). Further, the upcoming reform of the system (market stability reserve) is unlikely to yield the necessary effects (Sandbag 2016; European Commission 2017).

Due to the low CO_2-prices the introduction of a carbon floor price has been discussed. The idea is to introduce a minimum corridor of CO_2-prices and a first scheme had been introduced in 2013 in UK. It was designed as a dynamically rising levy so that the CO_2-price would continuously rise to roughly €35 or ¥4,227 in 2020 and €82 or ¥9,904 in 2030. However, meanwhile the levy has been frozen. During the review of the ETS a European carbon floor price had been considered in 2012 but has been rejected in favor of the above-mentioned market stability reserve (Ares und DELEBARRE 2016; SRU 2014, section 5.3.2). However, since the latter will not yield the necessary results proponents see a carbon price floor as a complement to bridge the carbon pricing gap rather than as an alternative. Therefore, France also considers the introduction of a national carbon floor price and also called for the introduction on the European level (Euractiv 03.03.2017). Meanwhile, the discussion goes to regional carbon pricing.

3.2.2.2 Introduction and build-up of renewable capacities

Renewable capacities are placed at the beginning (far left) of the merit-order by design of the remuneration scheme. One of the constitutional elements of the German feed-in tariff is the priority feed-in. The remuneration was originally exclusively a feed-in tariff and has been displaced with an obligation for newer capacities to market produced energy by themselves (see section 4.2). In the feed-in tariff system TSOs are obliged to accept whatever amounts of electricity have been produced and sell these on the spot market. This places RE-capacities at the beginning of the merit-order by regulation and secures relatively high full load hours even for variable capacities (wind and PV), i.e. whenever weather conditions permit. The introduction of the market premium model meant the first deviation from this approach as capacity owners have to market the electricity themselves (or through an intermediary) as shown in section 4.2.2.2. Meanwhile, the European Commission aims to abolish priority feed-in except for RES-capacities smaller than 500 kW (and CHP) (European Commission 2016/0379; Litzenburger 2017). The idea is that capacities shall react to negative market prices and stop production. Further they shall stop production in the event of grid congestion where they have now to be curtailed from the grid operator and receive a compensation (for details see section 4.2). The amount of curtailment also depends on the amount of necessary conventional capacities (“must-run”) in the grid (see section 4.1.2.2).

3.2.2.3 Combined heat and power

Combined heat and power (CHP) receives a fix premium per kWh produced, i.e. to the marginal costs where smaller units receive a higher premium (§ 7 KWKG). Because of this and because of revenues from heat production they usually stand before (i.e. left of) comparable non-CHP plants in the merit-order. However, this also depends i) on the price for heat and ii) whether the revenue is actually used for lowering running costs or for debt service (see section 5.2.2). Furthermore, CHP capacities are as well operated by other aspects than the merit-order: first, CHP power plants are operated by industry companies and are used for own consumption. Secondly, due to their property of combined heat production they are still operated by heat demand rather than the merit-order and constitute a part of the so-called “must-run” capacities (see sections 4.1.2.2 and 5.2.2).

4 Financing capacities: market segments & players

4.1 Financing firm capacity

Firm capacities – as opposed to variable capacities in section 4.2 – are those capacities that can be actively steered or controlled (another expression is controllable or dispatchable capacities). These are usually fossil and nuclear capacities but also some renewable capacities such as biomass, geothermal and some hydro power (water reservoir and pumped storage). However, the following sections focus on those technologies that are important for the respective countries. Further, the sections also touch upon broader strategic issue and therefore may also refer variable capacities.

4.1.1 Japan

The government has been working on establishing new markets as the market reform. In order to secure firm capacity it considers 1) a baseload market, 2) a capacity market and 3) a non-fossil-value trade market. Further, it also considers some other markets. Table 11 shows the roadmap of planned markets and other market reforms.

4.1.1.1 Markets for firm capacity

4.1.1.1.1 Baseload market: securing baseload capacity access for newcomers

Incumbents' own most of economical baseload coal-fired, large-scale hydro and nuclear power plants to which new electric power companies have difficulty to access. As a result, new electric retailers cannot help meeting baseload demand with middle-load generating power plants such as LNG-fired thermal power plants. The objective of establishing the baseload market as a part of forward market is to make it easier for the new electric retailers to access to large-scale baseload generating power plants. Introduction of the scheme allowing trade of baseload power is expected to activate competition in the wholesale market.

Incumbents have been so far selling their excess power with high marginal costs at JEPX. In the meantime, they have been utilizing their baseload power with low marginal costs by themselves. The capacity demerger of J-Power's power sources (coal-fired thermal) or the voluntary program to utilize JEPX by incumbents have not made significant progress. Therefore, the government thinks that it is necessary to request incumbents to release baseload power through institutional arrangements in order to secure the workable baseload market and aiming at equal-footing of competitive conditions with new participants.

As the basic concept of a workable system, the government suggested the following.

- To enable new electric retailers to access to incumbents' baseload power sources, it is necessary to restrict transaction involving their baseload power.

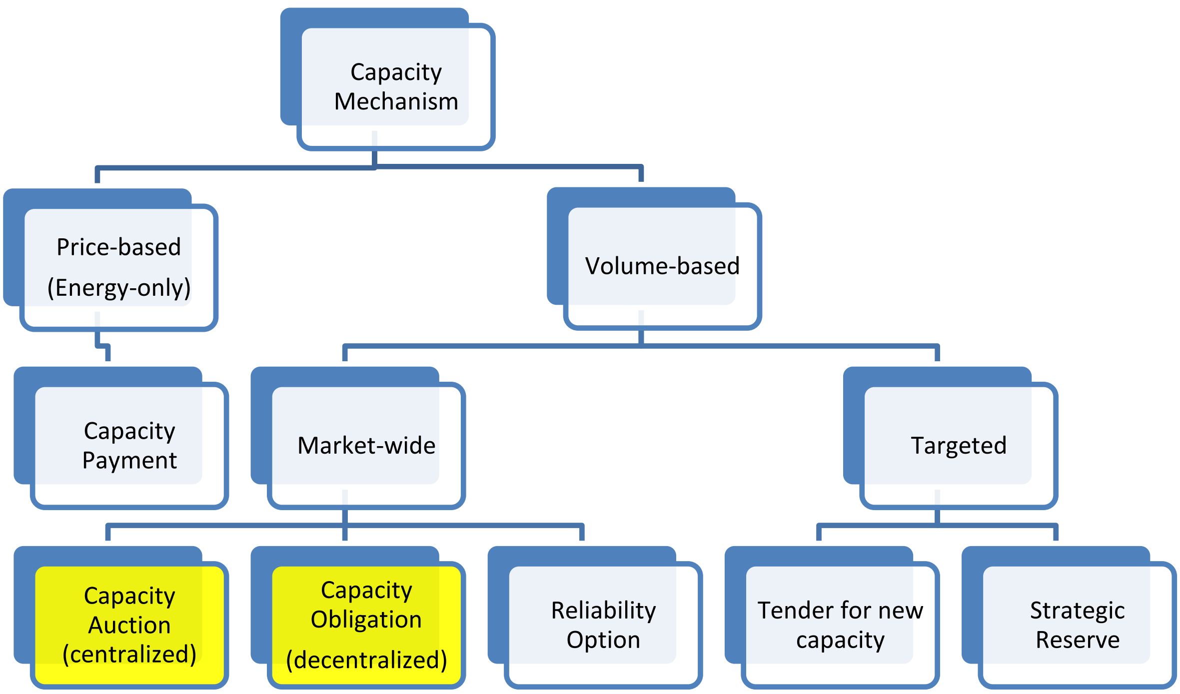
- To request incumbents to offer part of electricity generated by baseload power plants at a reasonable price in the baseload power market.
- Supply volume and price are set by taking into account necessity of public interests and burden sharing of nuclear costs.

4.1.1.1.2 Capacity Mechanism: securing baseload capacity

In the US and some of European countries, the capacity mechanism has been already adopted. The motives behind this market are common among liberalized countries though the type of capacity mechanism varies (Figure 32).

In Japan, the reason for considering capacity mechanism is at first lower predictability of recovering investment costs as transaction in the wholesale market expands. Secondly, necessity of balancing units is being heightened in order to accommodate PV and wind. In the meantime, the capacity factor of thermal power units as balancing units is expected to decline as a result of expansion of renewable energies. In another word, there are two motives behind setting up the KW market. One is to secure adequate generating capacities. Another is aiming at solving so-called "missing money" problem.

Figure 32 Various Measures to Secure KW



Source: JEPIC / own depiction

The government has not decided on the measure to secure KW. The government committee and the Organization for Cross-regional Coordination of Transmission Operators (OCCTO) have been conducting research on the design which fits Japan with studying the systems adopted by ISO/RTOs in the US and some in Europe. There are many issues to be addressed before determining the type of the capacity mechanism. Whether the eligible power source is including or excluding existing plants is for example the important issue in designing the capacity mechanism. Centralized or decentralized is another issue. In this connection, it is likely for the government to adopt the type of the centralized capacity market like PJM. The relationship between the wholesale market of JEPX and the capacity market is a crucial issue. Without wide and deep wholesale market, the capacity market might not work as designed. There are also many issues to be considered other than these.

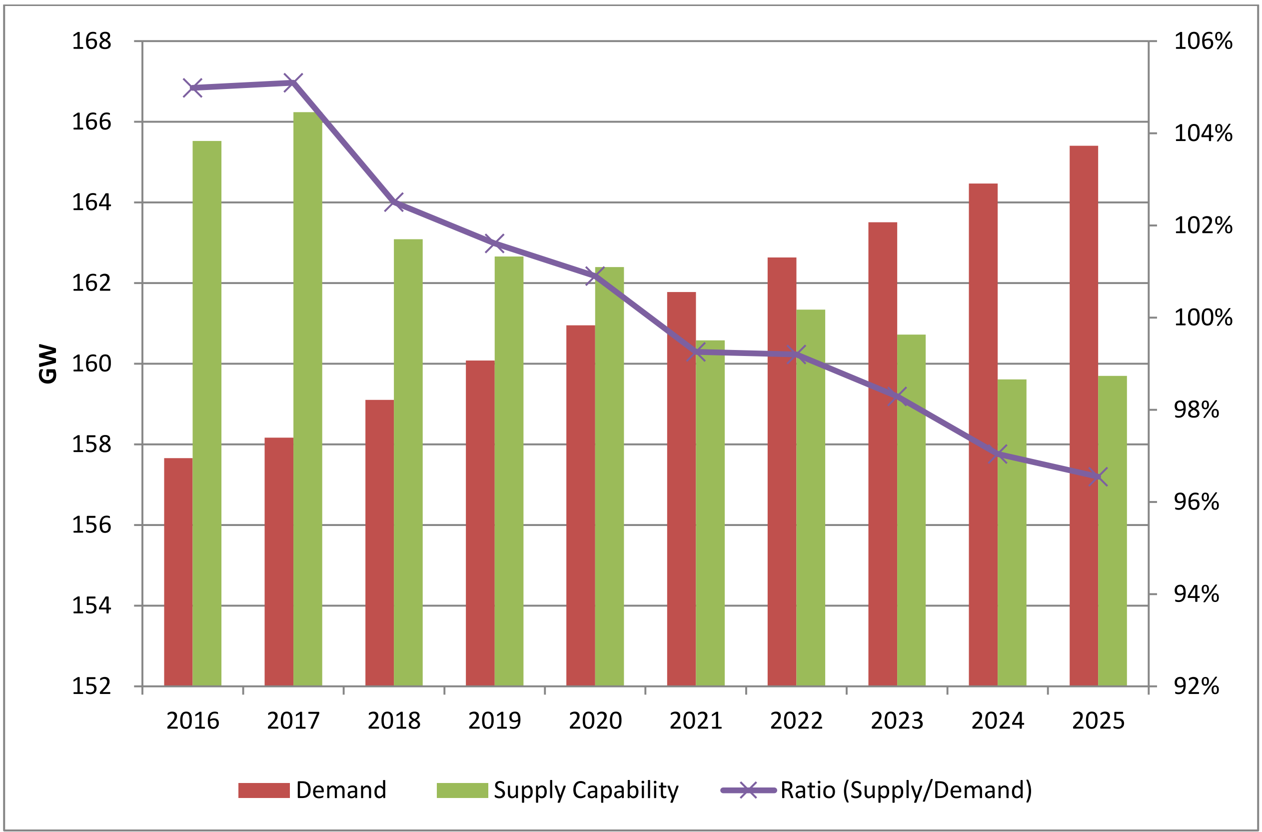
4.1.1.1.3 Obligation of retail supply companies and Non-fossil-value trade market

In the liberalized market, each retailer is required to secure power sources and submit the ten-year supply and demand plan to METI through OCCTO. As Figure 33 shows, the ratio indicating the degree of adequacy is going to decline over the years. This is because retail suppliers have not secured power sources in the mid and long-term yet.

Retail power companies are required to keep the ratio of electricity generated by renewable sources or nuclear power at 44% or more of their total supply in 2030. This targeted goal of 44% follows the targets of nuclear and renewable energies in generation mix in 2030 depicted in Long-term Supply and Demand Outlook formulated in 2015 as shown in Figure 17.

METI is planning to form a market for trading environmental values of electricity generation using non-fossil sources such as renewable energies and nuclear power in an effort to cut carbon dioxide emissions. The market enables retail power companies as well as households with PV to buy and sell environmental values associated with electricity generation using such non-fossil resources. Retail power companies as a new participant in the retail market have only limited means to procure non-fossil power sources. As a result, they may not be able to achieve the goal of 44%. In addition, FIT power turn into “grey” electricity as they will be traded at JEPX. That is, they lose their characteristic as being “green” (i.e. their environmental value) and cannot be distinguished.

Figure 33 Status of Capacity Secured by Retail Suppliers



Source: OCCTO 2016a, p. 13

The introduction of the new market is designed to promote the spread of environmentally friendly electricity generation using non-fossil resources. The government assumes that the new market will be able to lower purchase prices for electricity generated by renewable sources and reduce the burden of surcharges for the public.

4.1.1.2 Other market reforms

In addition to the above-mentioned establishment of new markets, the negawatt market is going to be opened at JEPX as from April 2017. The government is also planning to establish the real-time market by 2020. In this connection, incumbents had been procuring balancing units in each area by themselves. Now balancing units are procured by the public tender. The real-time market for balancing is the next step. The future market is also under consideration. Furthermore, implicit auction is going to be introduced to improve wide-area operation using interconnectors.

Table 11 Roadmap for New System in Japan

Institution	2017	2018	2019	2020	2021-
Base-load Market			To be opened	Delivery starts	
Use of Inter-connector		Implicit auction introduced			
Capacity Market				opened	Capacity contracts coming in effect
Non-fossil Value Market	Opened (FIT power sources only)		Opened (all non-fossil power sources)		
others	Gross bidding starts				

Source: ANRE 2017b

4.1.2 Germany

4.1.2.1 Markets for firm capacity

4.1.2.1.1 The broader picture of energy transition, baseload and firm capacity

Any needs assessment for firm capacity – or broader speaking for energy security – has to take account of the envisaged future energy system. This is particularly important in light of the long investment cycles in the energy sector where wrong investment decisions may easily create technology lock-in-effects over long time periods and/or stranded investment.

The energy transition strategy (see 2.2.4) has shown that the German energy system will be based on VRE as leading technologies. This requires the rest of the energy system to take on a serving function to these VRE: instead of adapting generation to load/demand, the other elements of the energy system (non-variable generation, demand etc.) will have to adapt to VRE generation. (SRU 2014, p. 20).

That is, a VRE-based energy system requires much higher flexibility than a baseload-based system. Numerous studies have shown that a number of flexibility options are available or can be developed. (Arvizu et al. 2012, ch. 8; Grashof et al. 2013; SRU 2014, sections 3.2, 5.3, 5.4; BMWi 2014b, p. 18; Bauknecht et al. 2016, ch. 5, Peek und Diels 2016, 2016, ch.3). From the studies these can be summarized as:

- flexible firm non-renewable and renewable generation capacities (incl. flexible system services)
- flexible demand (load management)
- regional connectedness: grid integration inside and outside Germany

- sectoral connectedness: sector coupling (buildings, transport)
- storage

It shows that firm generation capacity is just one element in a whole menu of options to ensure energy security. That is, generation capacities as a flexibility option compete with other flexibility options in order to ensure energy security at the lowest overall costs. Therefore, the necessary amount of firm generation is not fix and may decrease over time as other flexibility options become technically available and market design / regulation (e.g. pre-qualification) make them economically available (i.e. levels the playing field).

Secondly, it reveals that additional dimensions in the generation system itself now become highly relevant that played only a minor role before, namely flexibility. As fast ramping ability is now key, it is now the *kind* of capacity that matters, i.e. their capabilities. This is often technology specific. (SRU 2014, pp. 80–81; RAP 2014). Therefore, the new requirements for generation capacities do not fit well with the historically grown generation system. In Germany, the current backbone of firm capacity is often not flexible (nuclear, lignite, old coal capacities), i.e. they only have limited capability of fast ramping. Furthermore, these capacities are also technically and financially designed for running in base-load (nuclear, lignite), i.e., they need high full load hours to run efficiently (technically and economically). Lastly, large parts of these capacities are also emission intensive (lignite, coal). (Leprich et al. 2012; SRU 2014, p. 65)

Therefore, the generation system needs to undergo structural change in order to serve the flexibility needs of the energy transition. Instead of serving base, medium and peak load, the conventional generation system has to serve the residual load, i.e. the difference between demand and VRE-production. At the same time, this structural change is necessary in order to achieve the emission reduction targets. That is, the former base load capacities need to decrease significantly. The nuclear phase out is politically set with the last reactor to go offline by 2022 (§ 7 Atomgesetz, vom 27.01.2017). Reductions in lignite and hard coal capacities are also necessary due to emission reduction but also to increase the flexibility of the system and to improve the economics of the former mid-load capacities. These will mainly consist of gas-fired combined-cycle plants that are more flexible and more economical to run at fewer full load hours. But they run at higher marginal cost and stand further right in merit-order. Therefore, even though they are crucial for the energy transition incumbent gas capacities are not competitive as long as too many nuclear, lignite and hard coal capacities are in the system that set the price at too many hours throughout the year. Peak residual load capacities will be provided by open gas-turbines, DSM-Options and storage. (enervis 2014).

Due to the large overcapacities, the closedown of lignite capacities for emission reduction is also beneficial for the economics of the generation system as a whole. Currently, the overcapacities suppress wholesale prices and contribution margins. The removal of capacities improves the economics for the remaining capacities as a whole. Therefore, it may be even rational for an operator to close down single plants (or agree to this in political negotiations) if it sufficiently improves the economics of the operator's remaining own portfolio. For the same reason, the nuclear phase-out is also beneficial from a purely energy market point of view as an improvement of the economic situation for the remaining generation system is only expected upon the completion of the phase-out. (enervis 2015, pp. 45–47).

From an economic perspective, the efficient way to govern the structural change would be the European emissions trading scheme (see section 3.2.2.1). Raising CO_2-prices to appropriate levels would turn around the merit-order and improve the economics of less emission-intensive gas capacities and decrease the economics of emission-intensive lignite and coal capacities, respectively. This would also be necessary for whatever capacity mechanism may be used, if any, since even under such mechanisms significant parts of the income shall be generated by the energy-only market. A sufficient CO_2-price would therefore be of significant importance. (SRU 2014, pp. 76–80). However, the political reality is that the CO_2-price will not reach the necessary spheres in the necessary transition period (see 3.2.2). Therefore, Germany – despite stressing the importance of CO_2 prices – has started to close down emission-intensive baseload power plants in a politically negotiated process (see section 4.1.2.1.3).

The important role of gas capacities needs to be pointed out. They represent the most flexible and least emission intensive fossil capacities that will assume a leading role within the conventional part of the generation system. Furthermore, they are also suitable to produce electricity from renewable methane gas (reverse Power-to-gas) in later stages of the energy transitions with high shares of renewables. In situations of possible seasonal shortages of wind and sun (that may occur every few year) and resulting high residual load they may serve as a reserve when other flexibility options are exhausted. (SRU 2014, pp. 42, 48, 57) Therefore, gas capacities may be regarded as a no-regret option. This also shows that in later stages of the energy transition energy storage and renewable firm capacities will gradually take over the role from conventional firm capacities.

The availability of flexibility options differ over different time frames that need to be bridged. Typically, the shorter the time frame that needs to be bridged the more options are available (e.g. interruptible loads for cold storage houses as a DSM measure can be interrupted for 15-20min). That is, the longer the time period where VRE need to be replaced the more firm generation capacity (fossil- or RE-based) is needed. Furthermore, some flexibility options may be so rarely used that it may be characterized as an insurance (e.g. methane for long-lasting periods without VRE generation due to unfavorable weather conditions). (SRU 2014, pp. 62, 81–82).

4.1.2.1.2 Capacity Mechanisms I: Discussions on their need in Germany

4.1.2.1.2.1 Energy-only market and missing money

The market design for the electricity market of an energy transition has to fulfil several functions:

- coordinate electricity supply and demand at all times so that these are always in balance (coordination function)
- ensure sufficient finance for all necessary capacities and components of the system thereby directing investments in the direction where they are needed for the transition (finance function)
- create a level-playing-field for all flexibility options so that these can be supplied at the lowest overall costs

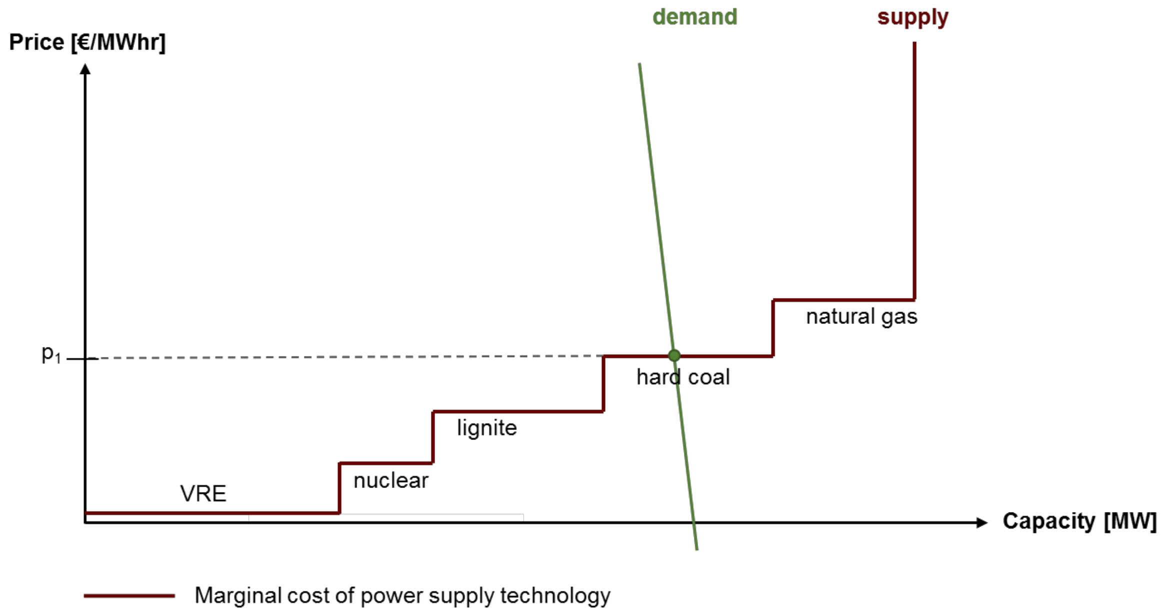
As laid out in section 2.1.3 German electricity markets have been liberalized as part of a European liberalization process. Section 3.1.2 has shown that the model of the energy-only market (EOM) has been chosen for the wholesale market where capacities are ranked by the merit-order, i.e. ascending by their marginal cost. Since only energy is traded on the EOM, the EOM takes on the coordination function and the financing function at once as can be seen from Figure 34: Capacities with rising marginal cost receive an award until demand is met and the price of electricity is set accordingly. Since the price applies to all capacities in use the ones left of the equilibrium receive a remuneration that is higher than their marginal costs so they can use part of it for debt services. In the example these are all the nuclear and lignite capacities. The last unit to receive an award is the “marginal power plant” that receives a remuneration just in the height of its marginal cost and therefore cannot serve its debt at that particular point in time. In the example this is hard coal. VRE are paid by another mechanism, namely the feed-in tariff and market premium (see section 4.2.2.2).

Rising shares of VRE also affect full load hours of conventional capacities and price setting in the EOM as already indicated above. Due to their priority feed-in and their very low marginal costs VRE’s electricity is always used first (capacities stand left and are used first)[5]. In times of low feed-in from VRE the VRE-bar is shorter and the whole merit order shifts to the left so that more residual load is needed to meet a given demand and price rises. High feed-in from VRE means a long bar of VRE and a rightward shift of the merit order and a low residual load with associated low price. With rising installed capacities over the years this effect has become structurally stronger and has

[5] However, if (i) prices get negative and (ii) VRE-capacities market electricity themselves under the market premium regime (see section 4.2.2.2, Appendix A and Appendix B) than they only bid into the market until the price gets “more negative” than the amount of the premium. If, at that time, it is still economical for conventional capacities to bid into the market (“economic must-run” – see section), they stand left of the VRE

led to a decline of average wholesale power prices. This has been coined the merit-order effect (Sensfuß et al. 2008). The merit-order effect has two effects on conventional capacities. Apart from declining full load hours mentioned above depressed power prices also lead to lower contribution margins once capacities are in service.

Figure 34 Merit-order



Source: IZES / own depiction

Declining electricity prices, however, can be attributed to a number of reasons and different studies rank these of different importance. Hirth (2016) attributes the price decrease of German spot prices between 2008-2015 to the merit-order effect (-24%), falling CO_2-price (-19%), falling fuel hard coal (-12%) and nat. gas price (-12%), fewer investments in coal and gas (-9%) and lower electricity demand (-8%). The nuclear phase-out, on the other hand, has a price raising effect of 22%. That is, structural change in the form of phasing out historical overcapacities is an important factor for the remaining capacities to raise the margins. According to Kallabis (2016) the most important factor to explain futures prices between 2007-2013 was the falling CO_2-price that caused a drop in spot market prices of -22%, followed by lower electricity demand causing prices to drop by -7%. The merit-order effect follows with -5% and falling fuel prices with -4%. Here, “changes in conventional capacities” only played a negligible role.

As prices on the wholesale market continuously decreased, a discussion on market design started in the German policy sphere at around 2011-2012 that centered around the question on whether the EOM would be able to finance investments in new capacities (SRU 2014, pp. 65, 73; Matthes et al. 2012, pp. 18–21). This so-called "missing-money-problem" became one of the main topics in the reform process on the electricity market design and centered around the question whether additional mechanisms to secure sufficient capacity should be established or whether the EOM would suffice to secure new investments. The EOM-based theory, on the other hand, is that prices only stay low as long as there are overcapacities in the market. Once these are gone prices would rise and peaks would occur regularly. These would provide sufficient incentives for new investments (Nicolosi 2012). That is, the question whether the EOM would be able to finance capacities and induce new investments became one of the main issues in the German policy discourse of 2012-2014.

4.1.2.1.2.2 Capacity mechanisms: capacity markets & strategic reserve

Additional capacity mechanisms, on the other hand, would establish an additional income stream where generators would be remunerated for the provision of capacity as such. The two large categories of capacity mechanisms are strategic reserves and capacity markets. The strategic reserve is meant as a backup for the EOM that is only used in "emergencies", i.e. when the electricity demand goes beyond supply and the market cannot solve. Then the strategic reserve steps in. The regulator purchases some amount of capacity credits (e.g. 5% of the maximum load) via auctions. These capacities do not take part in the normal wholesale market. They receive capacity remunerations and only get income from generation when they are used in the reserve. They are usually meant for old capacities at the end of their life time. (SRU 2014, p. 76 with further sources)

In capacity markets an additional income stream is created for capacities taking part in the EOM. Capacity credits would be purchased by the regulator (central model) or are traded on a separate market (decentral model) to the amount that is needed for *all* capacities in the market. These capacities would then bid into the EOM and sell energy. That is, all capacities receive two income streams. A number of different versions have been discussed for capacity markets. Apart from the question whether capacity mechanism should be central or decentral, a number of design options exists and decisions on these need to be taken by the regulator (Leprich et al. 2012, section 4.2; SRU 2014, pp. 73-5 with further sources).

- Scope (all capacities vs. newly built only): remunerations to all capacities would be perceived more fair but would incur windfall profits for old capacities with no debt service – cementing the current structure of the generation system.
- Technology-specifity: remuneration to selected technologies only may give more leverage to Government goals but may be also perceived as unfair.

- Inclusion of demand side and storage: The inclusion of demand side options and storage would include more flexibility options and potentially lower cost but raises complexity.

The possible benefits of capacity mechanisms need to be weighed against other issues. In particular, these are complexity of the instrument and the specific situation of Germany under the energy transition. Generally the introduction of a capacity market is highly complex and represents a deep change in the setup of the energy market. The introduction probably takes a number of learning rounds (i.e. a number of years) until they work reasonably well. Secondly, specific issues within the German context of energy transition arise. The introduction of a capacity market is a long-term policy commitment on the regulator's side because the investor has to commit to long-term investments. This is particularly difficult in the German context of the energy transition with changing requirements for firm generation as was laid out above. For this reason none of the international examples of capacity markets could have served as a role model. (SRU 2014, pp. 73–75). One proposal of a capacity market, called "focused capacity market", tried to tailor the model to the German energy transition context. It would take account of the above list by i) remunerating new capacities only when they are flexible and low carbon, ii) remunerating stock capacities only when they are on the verge of closedown, and iii) inclusion of DSM and storage (Matthes et al. 2012). As this, too, implies high complexity there were concerns that capacity markets overcompensate possible efficiency gains. This is particularly true when it comes from the theoretical concept to real world implementation, i.e. negotiations in the policy sphere. Also capacity markets raise issues of coordination within the common European electricity market if countries that introduce capacity markets are linked with electricity markets in other countries who do not.

A number of studies at that time (commissioned by the Ministry of Economics and Energy) concluded that the additional costs of introducing a capacity market would be higher than its potential benefits. That is, in an overall balance the (possibly enhanced) EOM (together with a strategic reserve) is regarded as the more efficient option (Connect Energy Economics 2014; r2b 2014; frontier economics und consentec). This has led to the electricity market reform as laid out in the following section below. It needs to be noted that the decision on whether or not to introduce capacity markets is not a pure cost-benefit analysis. It has been noted that specific setups of the electricity market also include (implicit) value judgements or "core beliefs" (Matthes et al. 2015).

The European Commission also raised concerns that capacity markets constitute an environmental harmful subsidy by supporting uneconomic or unsustainable generation (European Commission 2015, p. 14). Therefore, in the current proposal of the markets design ordinance (winter package) capacity mechanisms would only be introduced if they i) do not constitute state aid, ii) "electricity neighbors" are consulted, iii) do not create distortions or distort cross-border trade and iv) and only be introduced if the common generation adequacy assessment (see below) has identified a concern. Furthermore, only capacities with specific emissions below 550g CO_2/kWh would be allowed to participate (Article 23 European Commission 2016/0379; Litzenburger 2017, p. 14).

4.1.2.1.3 Capacity Mechanism II: Decision for of a strategic reserve and reliance on energy-only market

The discussion in Germany on capacity mechanisms and market design in general took over two years and involved a stakeholder process. The policy process took the following steps and was laid out in the following documents:

- A *Green Paper* on electricity market design in 2014 laid out the problems and possible solutions (BMWi 2014b)
- A commenting period in 2014 gave stakeholders the opportunity to comment on the Green Book and bring in their views
- A *White Paper* published the decisions in 2015 taking the stakeholder comments into account (BMWi 2015b)
- In 2016 a *law on the electricity market* was passed (StrommarktG) changing the relevant laws for those decisions of the white paper that could be implemented in the short-term
- The paper *Electricity 2030* identifies 12 long-term trends in the electricity sector that constitute further tasks for the coming years (BMWi 2016d).

The white paper provides the Government strategy for the setup of the electricity market. The concerns prevailed that capacity markets suppress electricity wholesale prices and conserve the current structure of the generation system thereby incurring additional costs (BMWi 2015b, ch. 3). Therefore, it was decided to keep and strengthen the EOM ("EOM 2.0") and to pursue reforms that incentivize new and flexible capacities to enter the market. Further, it was decided to introduce a strategic reserve as a backup measure.

The white paper proposes 20 measures divided across the three components "stronger market mechanisms" (measures 1-4), "flexible and efficient electricity supply" (measures 5-17) and "additional security" (measures 18-20) as shown in Figure 35 (BMWi 2015b, p. 55). The first component codifies the fundamental decision for an enhanced energy only market ("EOM 2.0") in the law on energy business, in particular a self-commitment to free price formation. That is, no regulatory price caps are allowed (§ 1a (1) EnWG) so that capacities have the possibility to finance themselves via price peaks. Strengthening balancing group management is also seen as the core of the EOM 2.0. The cost structure of the balancing energy system has already been adjusted earlier (see section 3.1.2) in order to increase incentives to the balancing responsible party (BRP) to keep their commitments. Balancing group management as the core of energy security in the EOM 2.0, however, has now been codified in the law on energy business (§ 1a (2) EnWG) and further refinements are under discussion (see section 3.1.2). Further measure include more transparency on the supervision of the abuse of market power.

Figure 35 Measures of the white paper

Component 1 "Stronger market mechanisms": The measures packaged in component 1 strengthen the existing market mechanisms. The required capacities can thus refinance themselves and the electricity market can continue to ensure security of supply.	
Measure 1	Guaranteeing free price formation on the electricity market
Measure 2	Making supervision of abuse of dominant market positions more transparent
Measure 3	Strengthening obligations to uphold balancing group commitments
Measure 4	Billing balancing groups for each quarter hour
Component 2 "Flexible and efficient electricity supply": The measures of component 2 optimise the electricity supply at both European and national levels. They thus ensure a cost-efficient and environmentally compatible use of capacity.	
Measure 5	Anchoring the further development of the electricity market in the European context
Measure 6	Opening up balancing markets for new providers
Measure 7	Developing a target model for state-induced price components and grid charges
Measure 8	Revising special grid charges to allow for greater demand side flexibility
Measure 9	Continuing to develop the grid charge system
Measure 10	Clarifying rules for the aggregation of flexible electricity consumers
Measure 11	Supporting the wider use of electric mobility
Measure 12	Making it possible to market back-up power systems
Measure 13	Gradually introducing smart meters
Measure 14	Reducing the costs of expanding the power grid via peak shaving of renewable energy facilities
Measure 15	Evaluating minimum generation
Measure 16	Integrating combined heat and power generation into the electricity market
Measure 17	Creating more transparency concerning electricity market data
Component 3 "Additional security": The measures of component 3 provide additional security of supply.	
Measure 18	Monitoring security of supply
Measure 19	Introducing a capacity reserve
Measure 20	Continuing to develop the grid reserve

Source: BMWi 2015b, p. 55

In direct connection with the fundamental decision for the EOM – and against capacity markets – the main measure of the white paper's third component ("additional security") is the introduction of a strategic or capacity reserve to complement the EOM 2.0 (§ 13e EnWG). It is meant as security measure in case the spot market does not provide a market solution. The capacity will be around 5% of maximum load and be build up during the winters of 2018/19 and 2020/21 where 2 GW each will be contracted. That is, the price will be determined by auctions. The necessary amount is monitored continuously (BNetzA 2017b). As indicated above, these capacities are not allowed to market energy. They are also not allowed to return to the market after they have been used in the reserve so that the capacity reserve cannot be used to artificially prolong the life time in times of low prices. Therefore, it is meant mainly for capacities at the end of their life time. Flexible loads (DSM) are also allowed to apply. Further, the capacity reserve is to be coordinated with the network reserve that already exists and is extended by the white paper / law on energy business beyond 2017 (§ 13d EnWG; BMWi 2015b, p. 78). The network reserve serves for network security and is used by the TSO's to balance the grid if BRP's do not keep their commitments. Further it is used for redispatch, voltage stability, in case of network restart etc. Capacities of the network reserve need to be located at relevant network spots, mainly in Southern Germany, some may also be in European countries abroad. Further, with the law on electricity market it was decided that network operators themselves may build and operate capacities ("network stability capacities") if network stability cannot be secured otherwise (§ 13k EnWG). Finally, the monitoring method shall be developed further that goes beyond the provision of conventional power plants on a national basis. It shall take a regional (i.e. cross-border) perspective and take account of probabilistic effects, smoothing effects of RES as well as DSM and storage (BMWi 2015b, pp. 79–80; PLEF 2015a).

In parallel to the process on market design, additional instruments to phase out coal capacities, in particular lignite, where discussed in order not to miss the German CO_2 emission reduction targets for 2020. As other proposals that would have worked via the ETS met too much political resistance, a "lignite reserve" was also decided as part of the law on the electricity market that takes lignite capacities out of the market. The lignite reserve as an emission reduction measure is declared as a last "ultimate" reserve of the electricity market. The goal is to abate an additional 12.5 Mt CO_2-emissions by 2020. For this, 2.7 GW of old lignite capacities shall be phased out in 2016-19. The capacities shall stay in the reserve for 4 years and go out of service thereafter. During that time, they shall receive equal payments of what they would have earned in the market. As the last "ultimate" reserve of the electricity market their ahead warning time is 10 days. After that they need to be able to provide minimum load within 11 hours and reach their nominal output within another 13 hours. This solution was found after the proposed instrument of a "national climate contribution" met heavy resistance by the lignite industry and associated unions. In this proposal older capacities (beyond 20 years lifetime) would have had to buy additional emission certificates from the ETS when their specific emissions go beyond certain limits (with decreasing limits at rising age). That way i) the oldest capacities would have been targeted and ii) additional CO_2-certificates would have been taken off the market so that these are not freed for emissions elsewhere in Europe (so-called waterbed-effect) (BMWi 2015a). However, the lignite reserve was then proposed by the lignite industry (IG BCE 2015) and implemented by the Government despite heavy criticism that it does not reach the targets and is more expensive and large parts of the capacities would have left the market anyway (Agora Energiewende 2015).

4.1.2.2 Other market and forms: Longer term issues and “no-regret” measures

The white book’s second component (“flexible and efficient electricity supply”) includes a large variety of measures that are considered beneficial regardless of the decision on capacity markets. These have been denoted “no-regret measures” in the green book. They are in line with earlier analyses where no-regret measures have been pointed out with regard to raising flexibility in order to strengthen the financing capability of the wholesale market to lessen the need for capacity markets: Apart from raising the CO_2-price these no-regret measure work via i) strengthening the intraday with respect to the day-ahead market ii) raising elasticity of demand (DSM) and iii) European Integration (better utilization and increased capacity of connectors, standardized market rules etc.). (SRU 2014, pp. 76–87).

The strategy paper “Electricity 2030” defines longer term strategic tasks that need to be dealt with in the coming years (Figure 36). These measures, too, serve the aim of raising the flexibility of the energy system, some by dealing with specific aspects others by improving wider framework conditions. That is, they also serve the strategy of strengthening the EOM in the wider sense. However, for these tasks listed here strategies need to be developed and open questions need to be answered. Some tasks have already been taken up in the white paper and need to be developed further as VRE shares rise. Other tasks are different and/or new(er). For all tasks the 2030-paper asks some guiding questions for further work. The measures of the white paper and the tasks of the 2030-paper that relate to firm capacity are dealt with here.

Some of the white book’s measures have already been implemented via law on the electricity market. Increasing transparency (measure 17) as a central new goal of the refined law on energy business shall be implemented via a new web-based national information platform on electricity market data (electricity production, load, import, export etc.) as well as a registry on all capacities, operators etc. to act as a one-stop-shop. The registry shall also include back-up power systems to better enable their participation in the market (measure 12).

The process of opening the markets for control reserve for new participants (measure 6) already started in 2015 with the adjustment pre-qualifications in order to enable wind and battery capacities and smaller units in general to take part in these markets as noted in section 3.1.2. Last clarifications for the implementing agency (use of uniform pricing) have now been set. In addition the control reserve has now been tailored to DSM capacities and aggregators. By defining management rights and duties of aggregators they can access DSM potential by “collecting” small users (measure 10). The 2030-paper defines system stabilization (task 10) as an ongoing process where further concepts (apart from market opening for RES and DSM for ancillary services) for ever increasing VRE-shares are pursued.

Figure 36 Trends and tasks of the 2030-Strategy

12 TRENDS	12 TASKS
1 The system is shaped by the **intermittent generation of electricity from the wind and sun.**	Make the electricity system more **flexible**
2 There is a significant decline in the use of **fossil fuels in the power plant fleet.**	**Reduce carbon emissions reliably,** shape **structural change**
3 The electricity markets are **more European.**	**Integrate and flexibilise** the European electricity markets further
4 **Security of supply** is ensured within the framework of the European internal market for electricity.	Assess security of supply in a European context **and develop common instruments**
5 Electricity is **used far more efficiently.**	Strengthen **incentives for the efficient use of electricity**
6 **Sector coupling:** The heating sector, cars and industry use more and more renewable electricity instead of fossil fuels.	**Improve competitive conditions** for renewable electricity in the heating and transport sectors
7 **Modern CHP plants** produce the residual electricity and contribute to the energy transition in the heating sector.	Provide **incentives for modern power and heat systems**
8 **Biomass** is used increasingly for transport and industry.	Provide incentives so that **biomass is increasingly used for transport and industry**
9 **Well developed grid infrastructures** create flexibility at a low cost.	Expand the grid **in a timely, needs-based and cost-efficient** manner
10 **System stability** is guaranteed even with a large share of renewables in the energy mix.	**Continue to develop and coordinate** measures and processes for system stabilisation
11 **Grid financing** is fair and meets the needs of the system.	**Further develop** regulations governing grid charges
12 The energy sector takes advantage of the opportunities offered by **digitisation**	Roll out **smart metering,** build **communication platforms,** guarantee **system security**

Source: BMWi 2016d, p. 6

An important aspect of firm capacities is the amount of necessary minimum generation – so-called must-run – in the system that is also connected to the issue of widening participation in ancillary service markets. Must-run supplies the electricity system with system services (voltage control, redispatch etc.) but is also a source of inflexibility that leads to grid congestion and the curtailment of VRE-capacities. Therefore, regular reporting of must-run from thermal capacities (measure 15) is also laid down in the law on the electricity market. It shall lay out the factors influencing must-run and their influence on VRE. Here, too, the 2030-paper carries the task of raising flexibility further (task 1), inter alia, by asking what additional approaches can be pursued to make must-run more flexible. Be the end of March the first report on “conventional minimum generation” has been published by the federal regulatory agency where hours with negative electricity prices have been analyzed. The report shows that only 15-20% of electricity production from conventional capacities account for must-run in the sense of the provision of ancillary services. The remaining 80-85% is conventional production that is due to technical inflexibility on the one hand and economic incentives that are stronger than negative spot market prices on the other hand. These economic incentives include heat production, self-consumption or taking advantage of special rules in the grid charge system (BNetzA 2017a).

Another important aspect of firm capacity is the treatment of combined heat and power (CHP) and how it is integrated into the electricity market (measure 16) and there are connections to the issue of must-run as well as mentioned above. This is outlined in a dedicated report where the role and challenges of CHP are laid out (BMWi 2017c). The main message is that CHP will provide residual load and is crucial for sector coupling with the heat sector as was already outlined in BMWi (2016d). Therefore, the issue has to be seen in connection with the must-run-issue (measure 15) as CHP will largely replace non-combined generation until 2030. That is, CHP needs to be modernized so that – as one aspect – heat and electricity production can be decoupled for a certain period of time. Other issues include new roles for heat grids that will not only distribute heat but also collect heat from various sources and at lower temperatures than before. Further, in order to find the most economic flexibility option, other technologies will compete with CHP, in particular power-to-heat capacities in industry and solar thermal and geothermal capacities in public heat supply. Future CHP-support has to take into account all these aspects, in particular competing usages across sectors. (BMWi 2017c). The 2030-paper asks further questions on CHP (task 7), in particular on how to map out the role for CHP in different sizes, situations, sectors and uses of input. Further, a market design needs to be spelled out that takes these issues into account as well as the interactions with the ETS. In part, this is also connected to the strategy of increasing the use of biomass in transport and industry (task 8). In general, this is necessary in applications where large-scale RE-based electricity use is more difficult (transport, heavy industry, buildings that cannot be retrofitted). That is, an overall market design needs to be found that governs the competing uses of biomass across sectors efficiently.

Another important aspect of governing firm capacity is the interrelation with emission reduction policies. As pointed out above, the lignite reserve was finally chosen in order to reduce CO_2-emissions from generation (task 2) since sufficient CO_2-prices were not available and other national instruments met too much resistance. Meanwhile, the strategy of a negotiated phase out of lignite and coal capacities is pursued (SRU 2015; Agora Energiewende 2016).

Integrating the electricity market into the European market (measure 5) is mainly an EU-driven process even though Germany constitutes an important player. In terms of firm capacity, it is more efficient to determine energy security / generation adequacy within a European framework as noted in component one (“additional security”). This too, is a continuous process carried forward by the 2030-paper (task 4).

Other European aspects relate to the cooperation in implementing the European target (measure 5 and 7) model which is a central aim of liberalization and, more lately, of the Energy Union (see section 2.2.2.3) and this is taken forward by the 2030-paper (task 3). In November 2016 the European Commission published a number of new proposals for directives and ordinances on market design, renewable energies, energy efficiency and EU-Governance (EU winter package).

4.2 Financing variable capacity

Variable capacities – as opposed to firm capacities in section 4.1 – are those capacities that depend on weather conditions and therefore cannot be actively steered or controlled. These are renewable capacities, mainly PV and wind, but also some Hydro power (run of river). However, very often variable is associated with renewable per se. Therefore, the sections focus on those renewable technologies that are important for the respective countries and the definition may not always be strictly applied.

4.2.1 Japan

Oil Crises in 1970’s awakened the necessity of developing alternative energies for oil which Japan depended too much on. Thereafter, various laws and policies have been enforced to develop and disseminate new energies including renewable energies. Among other things, Renewable Portfolio Standard (RPS) and Net Energy Metering (NEM) which is the system of purchasing excess generation from renewable energies of the customer’s site at the fixed price and the Feed-in Tariff (FIT) system have been major instruments to promote introduction of renewable energies in Japan.

4.2.1.1 Renewable portfolio Standard

Renewable Portfolio Standard (RPS) Act was implemented in 2003. Eligible renewable energies were solar, wind, biomass and hydro with less than 1,000kW. The objective of RPS was to secure stable energy supply, to contribute to tackle with global warming and to contribute to create new industries and employment opportunities.

Electric utilities were required to fulfill their obligation by one of three measures. That is, 1) generating electricity with own renewable energy facilities, 2) purchasing electricity generated by renewable energies from other entities, 3) purchasing green certificate corresponding to mandated electricity generation. The RPS target was set for 8 years ahead every four years. However, target itself was set at too low level. The target of the renewable ratio in total electricity consumption was just above 1% in 2010. Owing to the reason of low targets and others, RPS Act was abolished and replaced with the FIT law enacted in 2012 (ANRE, 2006).

4.2.1.2 Net metering

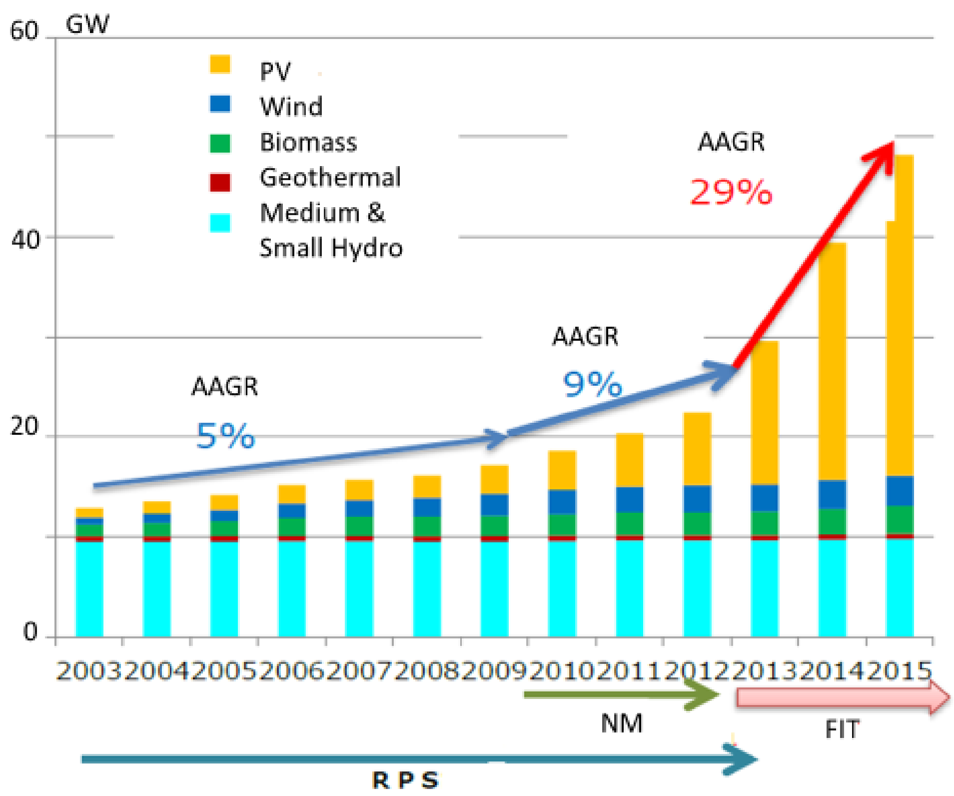
The PV power purchasing or net metering (NM) system was introduced in 2009 by the law though electric utilities had been purchasing surplus power from customers. Under this system, the electric utilities purchased excess energy that PV generators did not use themselves at the fixed price. The purchase price was ¥48 or €0.37 for residential customers and ¥24 or €0.18 for non-residential customers which were attractive prices for PV owners. And the purchased price was fixed for ten years. Purchasing costs were born by the public through electricity rates (JEPIC, 2017).

4.2.1.3 Feed-in tariff

As a predecessor of the feed-in tariff (FIT) the government enacted the Act on Special Measures Concerning Procurement of Electricity from Renewable Energy Sources by Electricity Utilities in August 2011. The law aimed at promoting the extensive introduction of renewable energy sources by requiring the electric utilities to purchase all the electricity generated by renewable energy producers. This Act led to implementation of the FIT scheme for renewable energy on July 1, 2012. This scheme has accelerated capital investment in renewable energy, with installed capacity since FIT's launch growing 138% to approximately 49,040 MW by the end of March 2016 (Figure 37). PV particularly grew significantly. As Figure 37 shows, majority of renewable capacities added after 2012 was PV, especially utility-scale PV. The lucrative FIT price set for PV was a reason for rapid diffusion. Another reason is that environment impact assessment is not required for not only roof-top PV but also majority of utility-scale PV. The central government does not have a rule of the environment impact assessment for PV. Local governments have some rules but almost all of utility-scale projects are exempted. In the meantime, such factors as availability of transmission lines, the level of

FIT prices and relatively longer-time duration needed for environmental impact assessment are hindering the development of wind energy resources.

Figure 37 Renewable Energy Capacity in Japan (2003-2015)



Note: AAGR and NM stand for average annual growth rate and net metering, respectively. FIT stands for feed-in tariff.

Source: ANRE 2017e

The electricity supply sources, purchase prices and purchase periods covered by the FIT scheme for each fiscal year are to be determined by the METI minister. The purchase prices and periods for fiscal 2016 are as shown in Table 12. The procurement price for solar power has been reduced from the previous year to reflect a fall in solar power facility costs.

Table 12 Purchase Price, Duration and State of Implementation of the FIT Scheme

Procurement type			Pre-tax price (€cent/kWh)	Duration (years)	Approval status*1 (MW): New approved amount*1	Approval status*1 (MW): Transferred approved amount*2
Solar	10 kW or above		20	20	75,287 (23,316)	— (261)
	Less than 10 kW (purchase of excess electricity)	Output controller not required	26	10	4,642 (3,951)	— (4,704)
		Output controller required*3	27			
	Less than 10 kW (dual generation / purchase of excess electricity)	Output controller not required	21			
		Output controller required*3	22			
Wind	20 kW or above		18	20	2,839 (478)	— (2,529)
	Less than 20 kW		46			
Offshore wind power *Installations requiring access by ship, etc.			30	20		
Geothermal	15,000 kW or more		22	15	76 (10)	— (1)
	Less than 15,000 kW		33			
Mid-/small-scale hydro *Excluding pumped storage hydro	1,000 kW–30,000 kW		12	20	776 (160)	— (208)
	200 kW–1,000 kW		17			
	Less than 200 kW		21			
Mid-/small-scale hydro using existing conduits*4	1,000 kW–30,000 kW		12	20		
	200 kW–1,000 kW		17			
	Less than 200 kW		21			
Biomass	Methane fermentation gasification		32	20	3,700 (517)	— (1,128)
	Woody biomass (thinnings, etc.) and agricultural crop residue	2,000 kW or above	27			
		2,000 kW or less	33			
	Ordinary woody biomass and agricultural crop residue		20			
	Construction material waste		11			
	General waste		14			

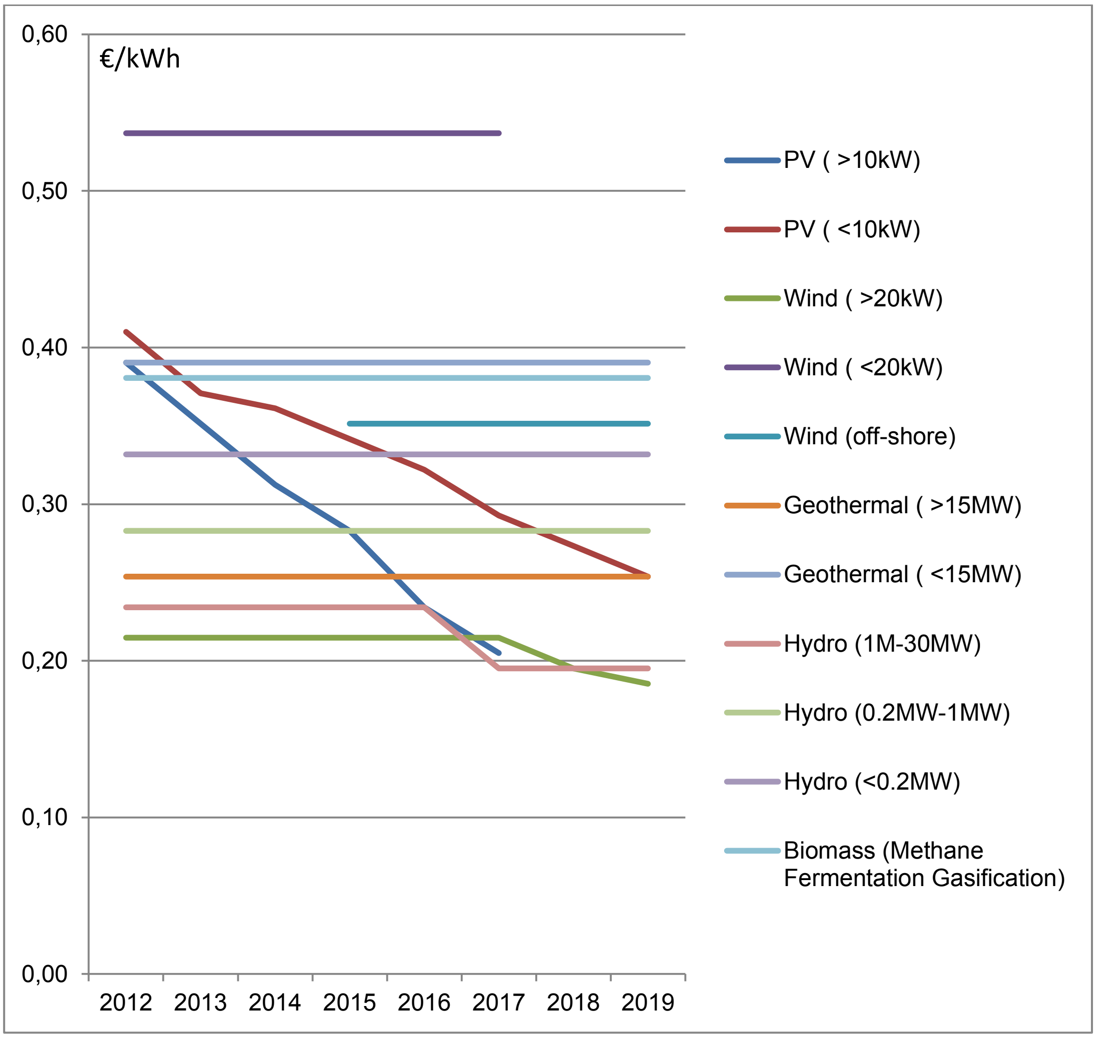
*1 As of the end of March 2016. The upper figures indicate facility capacity levels newly approved in preparation for introduction following the start of the FIT scheme.
Parenthesized figures indicate the capacity levels of facilities that have already commenced operation.
*2 Parenthesized figures represent as the transferred approved amount of those facilities introduced prior to the start of the system that applied the system after it began.
*3 In districts subject to supply and demand balance control by Hokkaido, Tohoku, Chugoku, Shikoku, Kyushu, and Okinawa EPCos, power plants for which connection
contract applications are received on or after April 1, 2015, must be equipped with output controllers.
*4 Upgrades to electrical facilities and penstocks utilizing existing conduits.

Source: JEPIC, "The Electric Power Industry in Japan 2017." p. 14.

Source: JEPIC, 2017, p. 14

Figure 38 shows FIT prices in the period of 2012 to 2019. Reduction of PV prices over the years is notable. Price reduction follows the similar path in Germany. The concern about soaring surcharges resulted in suppressing the FIT price for PV.

Figure 38 FIT Prices in Japan (2012 - 2019)

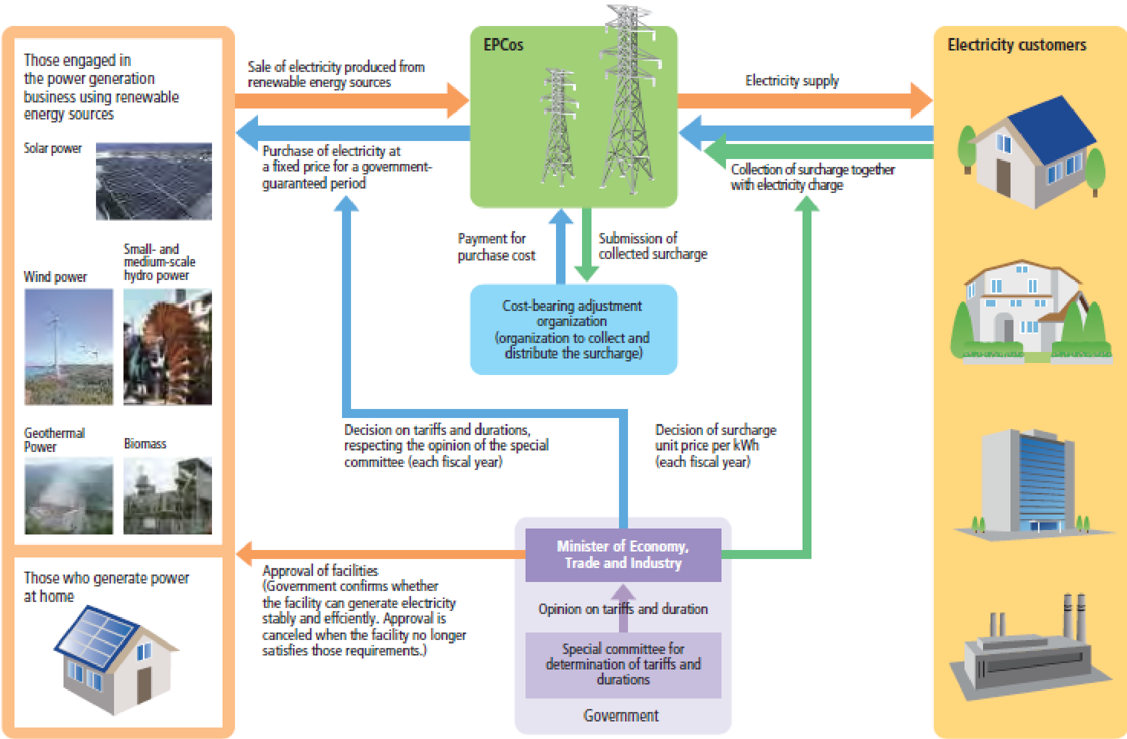


Source: ANRE 2017e

Electric utilities are obligated to purchase all electricity generated by renewable energy sources at a fixed price for a period specified by the government. The electric utilities are permitted to pass on their costs for the purchase of electricity generated by renewable energy sources to customers in the form of a surcharge calculated in proportion to the customers' usage volume. The surcharge for fiscal 2016 is €0.019 or 2.25 yen per kWh (€19 billion or ¥2.3 trillion for Japan as a whole) and €5.6 or ¥675 per month for the standard model household. Under this system electric utilities collect the surcharge from customers in proportion to the volume of electricity they use and transfer the funds to a cost-bearing adjustment organization, which refunds their purchase costs to them in due course (Figure 39). On the other hand, the scheme contains a provision that reduces the surcharge for customers who use large volumes of electricity and who satisfy certain conditions.

Concerns about growing backlog of unfinished PV projects in the FIT system led to a review of the system with the aim of preventing further occurrences, and a new rule was added stipulating that generator facilities that remain unfinished for long periods of time will have their accreditation canceled. In addition, with contracts signed after April 1, 2017, renewable energy will be purchased by transmission operators and not retail business operators as will be the case until that date.

Figure 39 Japan's FIT System



Source: JEPIC, 2017, p. 15

Other major points in revised FIT effective as from April 2017 are as follows:

- The middle and long-term price target for each power source has been set for the purpose of reducing costs with efforts and innovation by the entities. These targets are taken into account in determining the purchase price annually. Underlining aim is independence from promotional instruments such as FIT. Specifically, the target for the generating cost of non-residential PV is €0.12 or ¥14 per kWh in 2020 and €0.057 or ¥7 per kWh in 2030. As for residential PV, the target of the purchase price in 2019 is the same level of electricity rates for household use. And after 2020 selling price is targeted to be same level of the electricity market price. It can be said that these prices are not impressively low comparing to current prices overseas. And market prices are also uncertain. As for on-shore wind of above 20kW, the target price by 2030 is €0.06-€0.07 or ¥8-9. Regarding small scale wind with less than 20kW and off-shore wind, there are no definite figures as targets. There are no specific numbers as target prices for geothermal, small and medium size hydro and biomass. Stated goal for these renewables is also to be independent of FIT in the middle and long-term.

- For the power sources such as wind, geothermal, small and medium hydro and biomass which need a long lead time to develop, revised rule made it possible to set multi-year purchase prices to enable developers to raise predictability.
- To realize further price reduction through competition among entities, competitive bidding is applied to designated power sources. Specifically, it is applied to PV with more than 2MW. The first auction is to be held in October 2017.

As stated in the above, the renewable policy is changing. Direction of policy-making is toward the use of competitive force to reduce costs and being independent from subsidies as a core energy in energy mix.

4.2.2 Germany

4.2.2.1 Relevant characteristics of financing variable PV, on- and offshore wind

Having passed high learning curves in the past, levelized cost of energy (LCOE) of PV and onshore wind have become comparable – and in some instances even lower – to those of new conventional power technologies. Germany hosts a high technological variety of installed VRE:

- From small-scale PV on roof-tops to large-scale ground-mounted PV plants of up to 10 MW of size
- From small-scale onshore wind plants of the early years of wind energy utilization over onshore turbines of around 3 MW per plant, often grouped in wind parks, to large-scale offshore wind parks exceeding > 6 MW of capacity per plant

These technologies have very low operating costs and high capital intensity in common, making investment security more important than with other less capital-intensive technologies delivering firm capacity (Jacobs et al. 2016). Here, investment risks directly translate into risk premiums, making investment in these technologies more expensive. VRE generate power whenever weather conditions permit, which results in simultaneous generation from plants of the same technology over larger geographical areas. This affects the market value of VRE power, which declines systematically whenever the market share of the technology is (temporarily) high. This is true on a short-term time horizon – visible in power prices on the day-ahead and intraday power market -, but also in the longer-term. The longer-term effect – i.e. the decline of average wholesale power prices over the years as opposed to short-term day-ahead and intra-day power markets – of VRE has been termed the merit-order effect (Sensfuß et al. 2008), it increases along with the share of VRE in a specific market as was also shown in section 4.1.2.1.2. It does not only reduce income from power supply from VRE, but also from conventional sources. For VRE, however, this leads to a systematic cannibalization of revenue opportunities from wholesale power markets. The consequence: Even when VRE have reached LCOE of a similar level than their competitor conventional technologies, their capital intensity, combined with their price reducing effect results in a systematic competitive disadvantage, making investments less attractive to potential investors.

Fossil-fuel based conventional generation technologies still benefit from the fact that external costs (e.g. for CO_2 emissions) are far from being fully internalized, resulting in a distorted market to the disadvantage of new VRE capacity. High conventional (over-)capacities further reduce the attractiveness of investment in new VRE capacity, especially when both compete for limited grid capacity. High conventional generation from must-run units (delivering system services or as a buy-product from combined-heat-and-power generation – see section 4.1.2.2) and high VRE production together with low demand in specific situations (e.g. on weekends) have led to an increasing number of hours with negative power prices at the German wholesale power market. Grid restrictions also result in curtailment by grid operators, which can also reduce the revenues for the operator of the corresponding VRE plants (Jacobs et al. 2016). Both long-term power prices and curtailments are highly difficult to anticipate, especially during a deep system change like the transformation of the energy sector towards more sustainability.

As a result, VRE need a continued enabling framework to ensure bankability, if they are to expand further (Lorenzoni et al. 2013; Jacobs et al. 2016). This does not imply a need for subsidies, understood as support provided for by the state for an uncompetitive technology. Instead, the specific nature of investment in VRE (high capital and low operating costs, simultaneous variable generation) as laid out above needs a longer-term security on revenues (such as from long-term power purchasing agreements, PPA) than can be provided by short-term wholesale power markets. Two streams of revenues are sometimes mentioned to help finance VRE investments:

- VRE will increasingly provide system services such as balancing power. However, the revenues from these services cannot be expected to be sufficiently high to significantly ameliorate the long-term outlook on future cash-flows for individual RES projects as the market volume for balancing power is merely 4% of that of VRE-investments (Leprich et al. 2013a, p. 31).
- Especially in the US, a number of over-the counter long-term PPAs between private power consumers and VRE investors have been concluded recently. In

2015, around 3.4 GW out of 15.9 GW of new wind and solar capacity, have been financed in bilateral PPAs (Labrador 2016). For Germany, this market remains very limited, so far. Unless private customers have systematic incentives to enter into such bilateral agreements instead of purchasing power at the wholesale market, it would be unwise to expect a significant degree of investments via private PPAs. Additionally, such agreements take liquidity from the wholesale power market, which may be undesirable also for other reasons (e.g. to avoid market dominance).

Furthermore, quota models have been discussed in Germany as an alternative to feed-in tariffs. Here, the regulator obliges market participants (e.g. retailers) to hold a certain percentage of RES. Ideally, quota models are technology neutral so that renewable technologies compete against each other and the most efficient technology makes its way. Therefore proponents claim a higher efficiency of the instruments than in the case of FIT. However, other claim a higher efficiency of the FIT since it has proven to be very effective in lowering technology costs. Since quota models unify all the risks on the investors' side it would have translated in high risk premiums for the capital intensive technologies and appears doubtful whether the technologies that low costs today would have reached the state of mature and low costs they are in today (for a deeper discussion see: SRU 2014, section 5.5.1)

4.2.2.2 VRE investment policy in Germany

4.2.2.2.1 The "Stromeinspeisegesetz" 1990

The support of VRE already has a long history in Germany. Before 1990, it primarily consisted in funding R&D. While solar PV was not very advanced at the time, some farmers tried to connect small-scale wind turbines to the public grid, but were often hindered by the regional utilities who held regional monopolies (Kungl 2015) (see also section 2.2.1. The utilities mainly used two levers to prevent the feed-in from plants that would compete against their own overcapacities built up at the time: technical and financial conditions for grid access, and (unattractively low) remuneration for power from third parties (Mautz et al. 2008, S. 108). After the largest R&D program, creating a market for 100 MW of wind power and 1,000 "solar roofs" in 1988, 1990 saw the passing of the first feed-in tariff in the "Law for the feed-in of power from renewable energies into the public grid" (in German: Stromeinspeisegesetz; StromEinspG, vom 05.10.1990). It only consisted of five paragraphs and provided for obligatory grid access for third-party renewable plants and specified the remuneration to be paid: in the case of wind and solar power, the remuneration was the same: 90% of the power tariff for households of the regional utility. For solar PV, this remuneration was far from sufficient to set an economic incentive for new plants, but it motivated interested actors to lobby for cost-covering payments like for wind and biogas (Mautz et al. 2008, S. 79). Despite low expectations, installed capacity of solar PV rose from 2 MWp in 1990 to

30 MWp in 1999, that of onshore wind from 55 MW to 4,435 MW during the same time (BMWi 2017b).

With the relatively high household tariffs of the period before the liberalization of the European power market, this constituted an interesting incentive. Liberalization from 1998 onwards, however, was expected to reduce tariffs for end-consumers, thus endangering the incentives set for wind and PV. This was particularly problematic in the context of the obligations of the Kyoto Protocol signed by the member states of the EU in 1997 (ratified by Germany in 2002), to reduce greenhouse gas emissions by 21% by 2010.

4.2.2.2.2 The EEG 2000

Accordingly, in 2000, the support scheme was fundamentally reformulated into a new law, the “Law for the Priority of Renewable Energies” (Erneuerbare-Energien-Gesetz, EEG). When introducing the law, the government explicitly referred to external costs and subsidies for conventional energy not being reflected in prices and to structural discrimination of new technologies. It also argued that unit prices of RES stayed high because of to low market volumes of VRE, and the law was set to break this “vicious circle” by stimulating “a dynamic development in all fields of electricity generation from renewable energy sources” (EEG 2000). The following issues reveal the strategic motivations governing the design of the law (Lauber und Jacobsson 2016, p. 150):

- Not only private costs (e.g. for a utility) should be relevant, but full-cost recovery for investors in RES, as well as negative externalities and subsidies of competitors
- Costs and benefits of the law are to be assessed not over a short, but longer-term time frame
- A focus not on R&D but on market formation to reduce initially high per-unit costs of RES, i.e. by providing firm remuneration over a period of 20 years (supported by an annual 5% reduction in tariffs for solar power and 1.5% for onshore wind)

The EEG of 2000 was set to double the share of RES of total power consumption by 2010. For the first time, priority grid access of RES was guaranteed. The resulting costs were now to be spread over all transmission grid operators, so that customers in regions with particularly high RES feed-in would not bear higher costs than those in other regions. Like in the StromEinspG of 1990, not public budgets were to bear the cost of RES remuneration, but power consumers. Solar was only to be supported until a capacity of 350 MWp was reached (this provision, however, was taken back in an amendment of the EEG in 2003). For wind power, remuneration by kWh was differentiated according to wind speeds at the site of a plant, in order to set incentives for new plants also in less favorable areas, as well as to limit profit margins at more attractive sites.

As a result of the EEG 2000, installed capacity of solar PV rose from 114 MWp in 2000 to 435 MWp in 2003 and of onshore wind from 6.1 GW to 14.4 GW during the same time (BMWi 2017b)

4.2.2.2.3 The EEG 2004

The 2004 amendment of the EEG targeted a fix share of 12.5% RES of total power supply until 2010 and at least 20% by 2020. It introduced support for offshore wind generators, which, however, did not lead to any installations, since remuneration was in the same order of magnitude as for onshore wind. Generally, reductions in tariffs only applied to capacities to be installed in the future. Existing capacities where not affected in order to ensure investment security. That is, the status quo was preserved in the sense that they kept receiving the remuneration that was set by the law in force at the time of their start of operation to (the same applies, with certain exemptions, to further amendments of the EEG later on). The law also reduced administrative burdens for RES operators, clarifying that feed-in did not require the conclusion of a specific contract between the operator of the RES plant and that of the distribution grid. Grid operators were obliged to take off the power into their grid, even if this required an expansion of the capacity of the corresponding grid section. Until the end of 2008, the installed capacity of solar PV rose by factor 14 to 6.1 GW and onshore wind grew to 22.8 GW (BMWi 2017b).

4.2.2.2.4 The EEG 2009

The next major revision of the EEG, entered into force in 2009, further increased the target for RES to reach at least 30% of power supply in 2020 and to continue to grow afterwards. Like with the previous amendments, the complexity of the law increased along with the numbers of paragraphs, from 21 in the EEG 2004 to 66 paragraphs. To reflect higher steel and copper prices, remuneration for onshore wind was somewhat increased, but an annual tariff reduction of 1% for new plants remained. Tariffs for offshore wind were significantly increased, while those for solar were reduced for all size categories (because of strong cost reductions for solar, they were again reduced in 2010). In addition to scheduled tariff reductions for new solar plants of 9% per year, remuneration was also set to vary according to annual levels of new installations of PV plants. The law partly reduced payments for operators of small PV if they consumed part of the generated power themselves instead of feeding it into the grid. Together with the savings from reduced power purchases this resulted in an attractive incentive to maximize own consumption.

Grid operators received the permission to control RE plants > 100 kW connected to their grid and reduce their power generation in cases of grid congestion. Nevertheless, plant operators were to be compensated for loss of profit. Before, RES plants were only to be curtailed after conventional sources, however, without compensation. While until EEG 2004, RES power was sold centrally by Germany's transmission grid operators at the wholesale power market, EEG 2009 (with amendment of 11. August 2010) introduced first regulations for so-called direct market supply by RES plant operators on the wholesale power market on a voluntary basis. Until 2011, the capacity of solar PV increased to 25.5 GW, by 6.4 GW per annum since 2008. Wind energy reached 28 GW in 2011, 188 MW of which in the first offshore wind parks, gradually entering operation from 2009 onwards (BMWi 2017b, 2017d).

In 2010 the system on differential cost came into force that obliged the TSOs to market the electricity from RES at the spot market. The revenues are to be deposited at an "EEG-account", commonly managed by the TSOs. From that account the payments to the RES-plant operators are to be made as well and since these are higher than the revenues, differential costs incur. These differential costs are levied on the electricity consumers – the EEG-surcharge. This shows that the amount of differential costs directly depend on the revenue from the RES-electricity supply, i.e. the spot market price at the moment the supply occur. Furthermore, the more consumers are excepted from the levy the higher the levy gets for the remaining consumers (Matschoss und Töpfer 2015b, section 3.1; SRU 2011, pp. 265–266; Horst et al. 2014, S. 39ff).

4.2.2.2.5 The EEG 2012 and 2014

The 2012 amendment of the EEG was preceded by the temporary reversal of the nuclear phase-out decision between late 2010 and spring 2011, after the Fukushima accident (see section 2.2.4). The Energy Concept of 2010 slowed down the pace of RES expansion, to reach at least 35% RES of total power consumption in 2025 and at least 80% in 2050 (BMWi und BMU 2011). Tariffs for solar PV were further reduced to reflect recent cost reductions and high expansion rates, and the automatic tariff reduction (reflecting the current rate of new installations) was accelerated to a rhythm of every six months. Another "small" amendment of the EEG 2012 in summer 2014 introduced a global cap of 52 GW of solar, after which no remuneration (beyond market revenues) was to be paid to new solar plants. Until then, PV was set to expand by 2.5 to 3.5 GW per year; higher or lower installation rates would increase or decrease the automatic tariff reduction, which was again accelerated to be automatically revised every three months.

Already during the debates around the previous amendments of the EEG, calls had been voiced – under the term "market integration" – by representatives of the conventional utilities to adapt regulations applying to VRE to those for conventional energies. This included power price signals to be part of the remuneration for VRE and incentives to generate electricity according to day-ahead forecasts – implemented by the so-called floating market premium paid to VRE operators who chose to market their electricity themselves. It compensates for differences between the LCOE, which are approximated by the so-called "value applied" for each RES technology and the spot market revenues. The difference is not determined for every price and time step (e.g. per hour). Instead, the monthly average market value of each VRE technology is determined ex post, and the difference between the average market value and the level of remuneration guaranteed by law is payed to VRE plant operators (see Appendix A for a more detailed explanation).

Whilst feed-in tariffs only place the quantity risk (e.g. of less favorable weather conditions than expected) to RES power plant operators, a floating market premium shifts part of the market price risk from the society as a whole to RES power plant operators. The following goals were pursued with the introduction of the floating market premium (EEG-Entwurf 2014; Sensfuß und Ragwitz 2011):

- To set incentives for the feed-in of VRE power according to market price levels
- A reduced risk of negative prices at the wholesale power market
- An increase in competition due to a multitude of actors marketing RES power
- Improved forecasts for (V)RES power production and a reduced demand for balancing energy
- Marketing of RES power in virtual power plants

This move has not gone without controversy (Grashof und Weber 2014): Existing VRE plants can only reduce their power production along with power prices. Furthermore, incentives to design future plants so as to maximize benefits from the floating market premium (and minimize generation during times of low prices) are weak. Prospective investors cannot anticipate temporal patterns in power price fluctuations over a 20 year-lifetime of a VRE plant with high confidence. It depends on many factors, from the installed capacities of different generating technologies over the (lack of) expansion of cross-border electricity lines and transnational power market zones to the pace of an increase in demand-side management, power storage and other flexibility options affecting power price volatility. This insecurity leaves investors with one choice to minimize risks when planning future plants: to optimize the relation between installation costs and potential power generation, without consideration of power price variations. Direct market supply with the floating premium also sets an incentive to stop generating power despite good meteorological conditions whenever power prices reach a negative level that exceeds the (positive) value of the market premium the operator can expect to receive in the current month (for details see Appendix B). This undermines priority grid access of RES in times of negative power prices, while inflexible conventional sources still produce, thereby leading to additional CO_2 emissions. VRE plants stopping production in times of low prices also cause an increase of power prices during the corresponding period, which in turn reduces medium-term incentives for operators of conventional power plants to invest in measures to enhance the flexibility of their plants (for the issues of inflexibility and must-run capacities see section 4.1.2.2). Finally, this kind of market premium was argued to open the door for the creation of an oligopoly of direct marketing firms, which can indeed be observed today (see section 5.2.2): only 5 companies have contracted more than half of the nearly 60 GW of renewable capacity in direct marketing at the end of 2016 (Köpke 2017a). As a result, the negotiating power of VRE operators vis-à-vis firms involved in direct market supply differ, placing those operators with a small portfolio or plants producing at a typical pattern[6] for large areas in Germany at a disadvantage.

The move to a higher "market orientation" was supported by the growing level of the EEG surcharge, which distributes the costs for RES remuneration among final electricity customers. It rose from 1.12 ct/kWh in 2008 to 3.59 ct/kWh in 2012[7]. This increase was partly interpreted as evidence of overly high costs of expanding different renewable technologies, especially solar PV (Sigmund und Stratmann 2012; Frondel et al. 2010). Empirically, however, this increase can be attributed to a number of factors:

- Wholesale power market prices have decreased considerably since 2008 (partly due to the merit-order effect mentioned above, as well as because of higher competition in power generation in general, reduced power demand and a decline in ETS certificate prices), so the difference between market revenues and guaranteed remuneration to be covered by the EEG surcharge has increased – see above and section 4.1.2.1.2.
- There are numerous exemptions from the obligation to pay the EEG surcharge for industrial consumers and they increased from 78 TWh in 2008 to 86 TWh in 2012, for which only part of the EEG surcharge had to be paid (BMWi 2016a, S. 13). In 2012 alone, 18% of the EEG surcharge payment per kWh of household consumers were caused by privileges for industrial power consumers[8].
- This limits negative effects on the competitive position of energy intensive companies from the expansion of RES in Germany – but also increases the costs for the remaining end customers visible in the level of the EEG surcharge.
- The installations of solar PV plants have indeed achieved high levels between 2009 and 2012, but so have the corresponding LCOE and paid remunerations: from Q3 in 2010 to Q2 in 2012 only, costs for new PV plants in Germany decreased by 35% (Kost et al. 2012, S. 14; Kelm et al. 2014).

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6 Referring to plants with weather conditions similar to many other plants, which influence hourly power price levels if their cumulative capacity is large enough. The more the production pattern of a plant resembles the average production pattern of large generation capacities, the higher the revenue-reducing impact on the revenues of that plant.

7 See overview per year at https://www.bundesnetzagentur.de/SharedDocs/FAQs/DE/Sachgebiete/Energie/Verbraucher/Energielexikon/EEGUmlage.html

8 Own calculation on the basis of the data available at the site of the transmission grid operator TransnetBW https://www.transnetbw.de/de

An increase in the EEG surcharge also does not necessarily imply an identical rise in power prices for end consumers. With sufficient competition in the retail market, reductions of the wholesale power prices can be expected not to be incorporated by utilities' profits but passed on to consumers. Nevertheless, it was proposed by the then Environmental Minister to freeze the EE surcharge level until 2014 and limit further increases to max. 2.5% per year, i.e. with retroactive cuts for RES plants already in operation[9]. This sparked high controversy also beyond the affected branches of industry and was ultimately rejected to avoid a general loss of credibility of EEG-payments with future investors.

With EEG 2014, direct market supply became mandatory for new RES plants of a certain size, and guaranteed feed-in tariffs centrally marketed by the transmission grid operator an exemption only available for smaller plants (with size thresholds decreasing gradually). Again, older capacities are still remunerated according to the old regime and tariffs at their respective times when they went into operation. The planned RES expansion targets were reduced compared to objective of *at least* 35% of power consumption by 2020 (see above), although not very transparently: by 2025, 40 to 45% of total power consumption were to be supplied by RES, and 55-60% by 2035. At the end of 2013, RES had already reached a share of 24% (BMWi 2017b). This shift in the intention of the lawmakers was also reflected in a change of denomination: from "Law for the priority of renewable energy sources" (until EEG 2012), EEG 2014 was titled "Law for the development of renewable energy sources"[10]. Remuneration for power from PV and onshore wind was set to in-/decrease automatically in case a pre-determined corridor of 2.4 to 2.6 GW per year was not attained. Procurement for PV modules usually occurs within weeks or months depending on the size of the plant, so investors can anticipate the remuneration for "their" project relatively well before placing an order. For the long lead times of onshore wind projects, this is not the case. Here, decisions to order turbines (the most costly part) need to be placed about two years before operation of a plant starts (Pietrowicz und Quentin 2015), so the short cycles of the automatic tariff reductions introduce a major insecurity for investors. For offshore wind, expansion plans were equally reduced, to a total installed capacity of 6.5 GW in 2020 and 15 GW until 2030, to be attained via limited capacities for grid connections for offshore wind plants. The fixed expansion volumes of on- and offshore

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9 http://www.spiegel.de/politik/deutschland/energiewende-altmaier-und-roesler-einigen-sich-bei-strompreisbremse-a-883266.html

10 Unofficial English translation of the EEG 2014 made available on the site of the Federal Ministry for Economic Affairs and Energy: https://www.erneuerbare-energien.de/EE/Redaktion/DE/Gesetze-Verordnungen/eeg_2014_engl.pdf?__blob=publicationFile&v=4

wind and PV were mainly justified with the aim of limiting the EEG surcharge (see above).

Own consumption power – or prosumerism – from small PV plants became very attractive by 2014, but was increasingly seen as a lack of solidarity on the part of end-consumers operating such plants who were able to avoid paying their share of system costs (grid fees, taxes, EEG surcharge etc., see section 5.2.2) – in contrast to those consumers who did not have this option (e.g. tenants in apartment buildings). Accordingly, operators of new RE plants > 10kW were obliged to pay 30% of the regular EEG surcharge in 2014 (with further increases later of up to 40% as of 2017) also for power they did not procure from the grid but directly from their own PV plants within the same building.

Pilot auctions for ground-mounted PV in 2015 and 2016

Six auction rounds were carried out from April 2015 to December 2016, for remuneration in the form of a floating premium for 150 to 200 MW per round. In each round, bid volumes exceeded demand by factors of 2 to 3.5, and average price results declined over time. No systematic analysis has been carried out so far, so it is not possible yet to attribute this development to potentially relevant factors. Plants that were successful in the auction rounds are obliged to start operation within 18 months, an extension of 6 months was accepted with some penalties. Accordingly, it is too early to determine for which share of successful bids plants have been realized: the extended deadline of the first round ends in May 2017, that of the second in August 2017. There is also no systematic analysis yet what kind of actors have won bids, and if the more risk-intensive nature of the auctioning scheme leads to a change in the actor structure in the market for ground-mounted PV.

Another major move in the EEG 2014 was the outlook on the introduction of auctions for determining the level of remuneration for RES. Until EEG 2014, remuneration for the different RES technologies had to be changed by amending the law. That is, after new feed-in tariff rates had been proposed by the responsible ministry (backed by scientific analyses) they became subject of the parliamentary negotiation process. A system of pilot auctions (with 6 rounds in 2015 and 2016) was introduced by EEG 2014, to serve as a test for switching to auctions also with other RES technologies, to be introduced "at the latest" in 2017, after another amendment of the EEG. The main goal of this system change – the largest since the creation of the EEG in 2000 – was to introduce competition in determining remuneration levels and who was to be entitled to that remuneration, and to "reach the goals of the energy transition with lower costs" (EEG-Entwurf 2014, S. 110). Officially, the German government argued that the EEG did not constitute state aid according the competition rules of the European Union. However, it still notified the 2014 amendment with the European Commission in parallel to discussing the draft of the law in the German parliament, where it was adopted on July 3rd 2014. On July 23rd 2014, the European Commission found the new EEG to be in line with the European Energy and Environmental Aid Guidelines adopted in April 2014[11] - introducing auctions had been a major goal of the guidelines.

4.2.2.2.6 The EEG 2017

The EEG 2017 introduced auctions as the standard method to determine the level of remuneration (floating premium) for new plants. Administratively set remuneration became the exemption from the rule for smaller plants, for PV and wind onshore < 750 kW. Pilot wind energy plants (the first two plants of a new model to be installed in Germany or plants for specific research purposes) are also exempted. In contrast to the hopes expressed when formulating the EEG 2014, cost reduction is not mentioned as primary motivation for the shift to auctioning anymore in the explanatory statement for the EEG 2017. Instead, auctions are introduced "as a step for more proximity to the market and competition", they are assumed to be an objective, transparent and non-discriminatory approach" to determine payment claims in a competitive manner. At the same time, the government expected to improve the control over RES expansion, leading to an increased planning security for other actors of the power industry (EEG-Entwurf 2016, S. 172). When the auction system was designed, the government intended to reconcile three major goals (EEG-Entwurf 2016):

- To keep the expansion of RES within the limits of a corridors set in EEG 2014 (40-45% of renewable power consumption until 2025 etc.)
- To keep the total costs of the EEG low
- To keep the current variety of actors in the RES sector (because it increases competition, and community energy projects and local developers contribute to the acceptance of the energy transition)
- Another goal was not as explicitly stated, but nevertheless played an important role for onshore wind: to achieve a regional balance between new plants in windy regions in Northern Germany (with low per-kWh costs) and in areas less affected of grid congestion in the south)

The discussions of the responsible Federal Ministry for Economic Affairs and Energy and industry representatives on the design of the auction schemes showed that the government acknowledged frequent failures of RES auctioning to realize a high share of the projects that were successful in the auctions (Hauser et al. 2015; Hauser et al. 2016), and also the risk of squeezing smaller actors out of the market. The latter is not

[11] http://europa.eu/rapid/press-release_IP-14-867_en.htm

only probable in theory: actors with smaller portfolios and/or low equity are over-proportionally affected by the risk of sunk costs when their bids do not succeed, but has also been observed in a number of international RES auctioning schemes (Hauser et al. 2015; Hauser et al. 2016). The auctions for onshore wind therefore provide special regulations for bids from community energy groups.

For both onshore wind and PV, three to four technology specific auction rounds will be held per year[12] from 2017 onwards, auctioning remuneration for floating premiums for 2.8 (resp. 2.9 in 2020) GW of onshore wind and 600 MW of large PV plants. For offshore wind, the first two auction rounds in 2017 and 2018 will be carried out among holders of already granted construction permissions or whose permitting is already in an advanced stage. More rounds for offshore wind will follow later on for new projects.

Further auction formats to be realized in the coming years (due to obligations in the EU state aid guidelines) are

- Cross-border auctions with neighboring EU member states, for 5% of yearly new installed RES capacity (approx. 300 MW/year; preconditions include a bilateral cooperation agreement between the corresponding countries, that auctions are carried out in a reciprocal manner and that power can be physically imported from one country to the other)
- Technology-neutral auctions from 2018 to 2020 of ca. 400 MW/year: here, both onshore wind and PV projects will compete in the same auction rounds. The details of the ordinance are still under discussion. However, first proposals already reveal a considerable degree of fine-tuning affecting the chances of bids to win[13]:
    - Wind onshore bids in Northern Germany are to be limited because of transmission grid congestion (see section 4.1.2.2 on must-run capacities)
    - PV and wind bids for areas in need of distribution grid expansion are disadvantaged vis-à-vis bids for other areas
    - Wind onshore bids are to be assessed according to regional wind speed factors, in order to siphon of excessive rents at attractive wind locations

[12] The design of the auction systems for on- and offshore wind and PV differ significantly, and are quite complex. Therefore, they are not presented in detail here. The main elements of the auction systems are presented in English here: http://enr-ee.com/de/veranstaltungen/leser/konferenz-zu-photovoltaikausschreibungen-in-deutschland-und-frankreich.html?file=files/ofaenr/02-conferences/2017/170322_conference_appels_doffres_pv/Presentations/01_Dr_Karin_Freier_BMWi_OFATE_DFBEW.pdf

[13] See the principal features proposed by the responsible ministry here (https://www.bmwi.de/Redaktion/DE/Downloads/Energie/eeg-eckpunktepapier.pdf?__blob=publicationFile&v=8) and of the researchers advising the ministry on the issue in an internal memo.

  - Minimum quota for the awarding of bids are to be defined to avoid solar PV or onshore wind to claim large shares of the auctioned volumes
- So-called “innovation auctions” for (combinations of) RES plants with features providing specific advantages for grid or system integration, of a volume of 50 MW/year from 2018 to 2020. The details of the systems are still under discussion.

At the end of 2016, PV had an installed capacity of 41.3 GW, onshore wind of 45.4 GW, and offshore wind of 4.2 GW (BMWi 2017d).

Another new feature of the EEG 2017 is that the installation of new wind capacity will be capped in areas with insufficient transmission network capacity. That is, in those areas (‘network expansion areas’) new wind capacity under the auction scheme is limited to 58% of the average capacity that has gone into service in the years 2013-2015. The network expansion areas shall be one connected area not exceeding 20% of Germany’s area. (§36c EEG 2017). It is determined based on data that are used for the determination of the network reserve capacities (see section 4.1.2.1.3). The first network expansion area is located in Northern Germany and expands all across the coast line of the North Sea and the Baltic Sea (BNetzA 2017c). It is meant as a temporary measure until enough networks have been built. The current area is valid until 2020. It shall be evaluated until 31 July 2019 and every two years after that. (§36c EEG 2017). Furthermore, TSOs may contract CHP-capacities as sinks for renewable electricity that is then used for district heating (§13, Abs. 6a EnWG).

4.2.2.3 The actor structure in the market for variable RES

Until the 1980s, only little niches existed where pioneers of different onshore wind technologies worked on the improvement of technical design alternatives (such as, “should the rotor axis be horizontal or vertical?”) With the strong public opposition against the construction of a large fleet of nuclear reactors in Western Germany, the vision of an alternative energy system emerged. It was to be decentralized, rely heavily on principles of direct democracy and minimize environmental damages (Mautz et al. 2008). Some of the protesters against the existing energy system turned to experimenting with technological alternatives themselves, and joined the more technically interested pioneers of wind energy development already active in previous decades. While first ideas constituted in setting up forms of energy autonomy, most early projects rather attempted to connect their plants to the public distribution grid and sell the power to the regional utility. As pointed out in section 4.2.2.2.1, regional utilities usually tried to fight off this unwelcome competition for their own generation overcapacities. Despite strongly subsidized attempts of the Ministry for Research, big utilities only joined onshore wind R&D projects like for the 3-MW plant ‘Growian’ rather unwillingly - in 1982, the CEO of RWE was quoted in the journal ‘Die Zeit’ saying “We need GROWIAN (…) to prove that it is not possible” (quoted in Heymann 1995, S. 373).

Indeed the project failed – it was shut down in 1987 after 420 hours of operation - and showed operators of a new technology need a strong internal motivation to make innovation processes more fruitful (Mautz et al. 2008; Hoppe-Kilpper 2003).

The nuclear accident of Chernobyl increased the willingness of opponents to nuclear energy to develop and demonstrate alternative solutions. Due to the capital intensity of wind energy, the idea of “citizen’s power plants” (in German: Bürgerkraftwerke) spread, where a group of – oftentimes over 100 – interested individuals brought in enough equity capital to receive debt from banks. Despite the ideal of democratic decision making, the groups did not opt for cooperatives but chose to found limited liability companies, facilitating the acquisition of equity due to the limited financial risks. This legal structure, in turn, supported a gradual professionalization during the 1990s, when revenues from wind power became more reliable with the “Stromeinspeisegesetz” (see section 4.2.2.2.1), e.g. initially voluntary managers became paid employees, and business strategies gradually more expansive (Mautz et al. 2008, S. 54ff). The first projects were implemented at the end of the 1980s in Hamburg, where the proximity to the border facilitated learning from similar projects in Denmark. The good wind conditions made the German north east to the first region to benefit from onshore wind utilitzation. Farmers (Mautz et al. 2008, S. 60ff) constituted the other main group of investors in wind energy in the 1990s, lead less by idealistic motives but more by economic considerations to use their land and reduce their often high costs for electricity.

The implementation of PV projects followed onshore wind. During the 1990s, especially the concept of ‘citizen’s power plants’ developed for wind energy was realized increasingly with PV. Homeowners were the primary user group for small-scale PV plants installed on private roofs. Not financial attractiveness, but an ecological, clean and innovative image - and the high visibility of the plants – encouraged their installation in the early years (Mautz et al. 2008, S. 60). Like with onshore wind, not self-sufficiency constituted the preferred mode of implementation, but to feed the produced power into the grid. Also here, farmers constituted the second major group installing PV plants, making use of their oftentimes large roofs of barns. But as pointed out in section 4.2.2.2.1, due to the low remuneration provided by the federal Stromeinspeisegesetz of 1990, the operation of PV plants was still economically unattractive.

A number of roots and conditions of the early success of PV, onshore wind and biogas in Germany until 2000 can be highlighted (Mautz et al. 2008, S. 63ff):

- Technology pioneers, ‘change agents’ and opinion leaders served as disseminators in a decentral diffusion system
- Innovative social groups and networks gradually institutionalized into technology specific industry associations, professional component manufacturers

- A market for user-related service emerged, creating opportunities for professional wind project developers, specialized installers of PV panels or public consulting agencies (the first energy agencies)
- Operators of RES plants became increasingly professional and business-oriented, for onshore wind earlier than for PV, because large-scale solar projects only became more wide-spread at the end of the 1990s.

- Feed-back processes between manufacturers and operators, leading to technical and efficiency improvements of PV panels and wind turbines
- Advocacy coalitions formed between RES users/industry and policy actors (Lauber und Jacobsson 2016), which lobbied for and implemented pilot policy instruments, e.g. cost-covering solar remuneration in ca. 80 cities until 1999, preceding the EEG 2000 at federal level.

The enacting of the EEG 2000, together with amendments of planning and building regulations, further strengthened the economic incentives for new wind plants as well as the legal position of interested onshore wind investors with respect to land use in rural areas: wind power could now tap the mass market (Bruns et al. 2011, S. 297). The professionalization of actors increased further and first traditional energy utilities became interested in the sector, however, still at a very low level. One of the reason was the increasing capacity – and thus costs – of common wind turbines, which had now reached the level of 2 MW per plant. Institutional investors became important clients for professional project developers, from which they bought wind parks after their start of operation. The moderate returns but also low risks made wind energy especially interesting for assurances and similar financial actors. Utilities, however, continued to refrain from significant investments in renewables in Germany as laid out in section 5.2.2. The big four German utilities RWE, E.ON, EnBW and Vattenfall each founded subdivisions for renewable energy in 2007 and 2008. Their interest focused on wind energy, but corresponding investments occurred mainly abroad, while the national strategy concentrated on securing their dominant position with regard to conventional generation capacities (Kungl 2015, 18) until very recently (see Table 13). The model of community wind farms, in contrast, continued, albeit at lower market shares and with an increasing degree of professionalism and supported by services from specialized project developers.

So far, there is no scientific analysis of market shares of different actor categories for onshore wind. An attempt was made for the year 2012 as shown in Table 13 (trend:research und Leuphana Universität Lüneburg 2013, S. 42ff). The degree of transparency as regards methodology and data sources, however, is limited.

Table 13 Onshore wind market shares by investor types

	Market shares of total installed capacity (30.8 GW) in 2012	Market shares of net investments in new installations (2,566 Mill. €) in 2012
Institutional and strategic investors	12.2 GW (40%)	€1,047 Mill. or ¥107,451 Mill. (41%)
Utilities	3.1 GW (10 %)	€850 Mill. or ¥87,233 Mill (33%)
Single citizens as owners in the region of the plant	1.3 GW (4%)	€113 Mill. or ¥11,597 Mill (4%)
Groups of citizens in the region of the plant	6.3 GW (20%)	€245 Mill. or ¥25,144 Mill (10 %)
Citizens: Minority shares and cross-regional projects	8 GW (26%)	€310 Mill. or ¥31,814 Mill. (12%)

Source: trend:research und Leuphana Universität Lüneburg 2013

From 2000 onwards, the EEG – accompanied by supportive policies in the German states (Länder) – created long-term and quite stable framework conditions promoting the growth of a PV market and industry. The formerly idealistic motivation to install PV was gradually replaced by more economical interests, supported by the cost-covering remuneration provided for the first time with the EEG 2000. Mass production technologies were developed, supporting the set-up of an industrial policy orientation. The legal framework of cooperatives and the amendment of the German Cooperative Act (GenG) in 2006 facilitated the foundation of renewable energy cooperatives, especially of those with focus on electricity generation through PV. Based on a relatively simple business model these cooperatives could be run even by usual citizens with small shares of financial contributions, at least in the early years. As shown in Figure 40 the number of newly established renewable energy cooperatives per year rose from 8 in 2006 up to 167 in 2011 and made a total of about 850 renewable energy cooperatives in 2015 (of which 812 have been founded between 2006 and 2015) (DGRV 2016). User groups now included homeowners, self-organized citizen's groups (e.g. installing larger plants on roofs of public school buildings), farmers and medium-sized commercial operating companies (Mautz et al. 2008). Several solar industry associations were founded, and in 2006 merged to form the German Solar Industry Association (BSW). After 2004, a veritable PV boom occurred, putting pressure on German module and panel manufacturers to keep up with demand. The share of large-scale, ground-mounted PV plants increased continuously (and also the capacity in absolute terms, since the installation rates were significant) to 20% in 2010 and ca. 38% in 2012, supported by the global decline in module prices starting in 2009. This trend was reversed from 2013 onwards, when support for ground-mounted plants on agricultural areas was progressively withdrawn, maximum plant size was limited to 10 MW and module prices stabilized (Kelm et al. 2014, S. 2ff). Like for onshore wind, there is no scientific analysis of market shares of different actor categories for PV. The study mentioned above (trend:research und Leuphana Universität Lüneburg 2013, S. 42ff) also assessed the market structure for PV in 2012 (including all size categories) as shown in Table 14.

Table 14 PV market shares by investor types

	Market shares of total installed capacity (32.8 GW) in 2012	Market shares of net investments in new installations (13,265 Mill. €) in 2012
Institutional and strategic investors	15.7 GW (49%)	8,520 Mill. € (64%)
Utilities	1.1 GW (3.5%)	695 Mill. € (5.2%)
Single citizens as owners in the region of the plant	15 GW (46%)	3,908 Mill. € (30%)
Groups of citizens in the region of the plant	0.3 GW (1%)	55 Mill. € (0.4%)
Citizens: Minority shares and cross-regional projects	0.25 GW (0.8%)	68 Mill. € (0.5%)

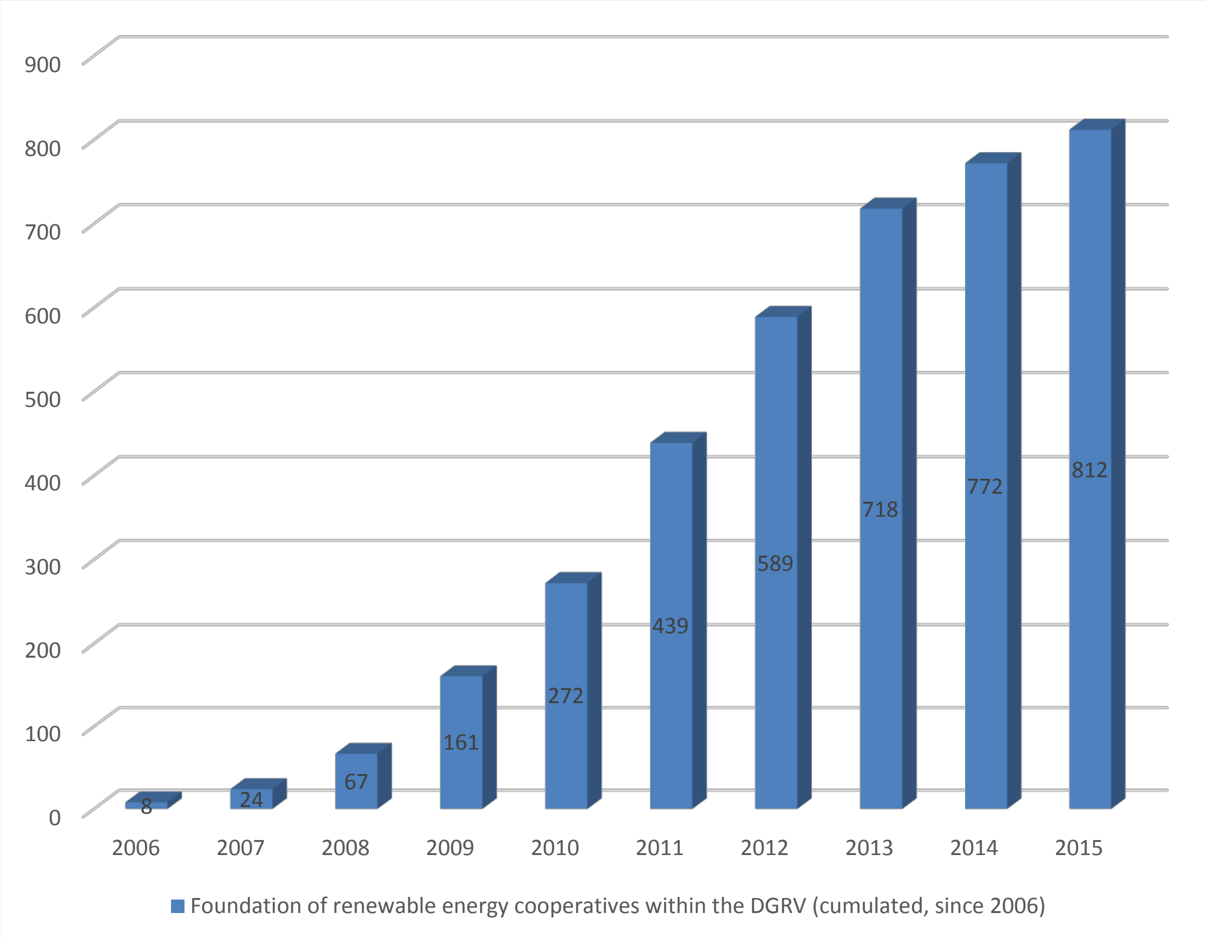
Source: trend:research und Leuphana Universität Lüneburg 2013

IZES gGmbH, together with Leuphana University of Lüneburg, have been commissioned by the German Federal Environmental Agency (UBA) to establish a systematic methodology for assessing the actor structure in the markets for onshore wind and large-scale PV. With this methodology, it will be possible to measure the actor structure of developers and owners of plants having started operations since 2010, as well as bidders and winners of each auction round for these technologies in Germany until late 2019. First results are expected for late summer 2017.

The actor structure for offshore wind is entirely different, largely driven by the specifics of this technology: very high capital costs due to the scale of the projects and very long lead times from project idea until operation start. Grid connection had turned out to represent a significant bottleneck, preventing a number of wind projects to deliver electricity for many months after completion. Accordingly, from 2009 to 2012, annual new offshore capacity with grid connection remained at low levels, but reached almost 240 MW in 2013, 490 MW in 2014 and 2,300 MW in 2015 – the latter year in which many delayed grid connections were finally realized. In 2016, 850 MW were connected to the grid and another 123 MW waiting to be connected (Deutsche WindGuard 2017; BMWi 2017d). The first offshore park, entering operation in 2009 – alpha ventus – belongs to the regional utility EWE as well as to E.ON and Vattenfall. The owners of the other German offshore wind parks in operation by 2016 include the aforementioned companies, RWE Innogy and EnBW, other German regional utilities (Trianel, Stadtwerke München, Entega), large utilities from Denmark (Dong), Switzerland (Axpo), China (Three Gorges Corporation) and one financial company, UniCredit Bank

München. Like with conventional generation technologies, large utilities own almost the entire offshore wind capacity.

Figure 40 Foundation of renewable energy cooperatives within the DGRV (cumulated, since 2006)



Source: IZES/own depiction, data source: DGRV 2016

4.3 Finance and regulation of electricity Networks

4.3.1 Japan

4.3.1.1 Network in Japan

The Japanese power grid is divided into two frequency systems: a 50 Hz system in eastern Japan and a 60 Hz system in western Japan. All the EPCOs, except Okinawa EPCO, are connected to the grid. The frequency difference is said to be dated back to 1896, when 50 Hz German-made power generation equipment was introduced in eastern Japan and 60 Hz US-made equipment in western Japan.

In eastern Japan, Tokyo EPCO and Tohoku EPCO ae linked by 500 KV AC transmission lines, while Tohoku EPCO and Hokkaido EPCO are linked by ±250 kV DC submarine cables. In western Japan, Chubu EPCO, Hokuriku EPCO, Kansai EPCO, Chugoku EPCO, Shikoku and Kyushu EPCO are linked by 500 kV AC transmission lines. Chubu EPCO and Hokuriku EPCO are also connected by back-to-back DC linkage facilities (300 MW), while Kansai EPCO and Shikoku EPCO are linked by ±500 kV DC submarine cables (operating for the time being at ±250 kV). The 50 Hz and 60 Hz systems are linked by the interconnections between the Tokyo EPCO and Chubu EPCO networks (Sakuma Frequency Converter (300MW), Shin-Shinano Frequency Converter (600 MW), and Higashi-Shimizu Frequency Converter (300 MW): total 1,200 MW).

OCCTO plays the lead role in considering plans to enhance these interconnections taking into account individual utilities' views. As of October 2016, enhancement work has started on the Hokkaido-Honshu interconnection (600 MW → 900 MW), while enhancement of the Tokyo-Tohoku interconnection is in the planning stages. It has been decided that the Shin-Shinano Frequency Converter at the Tokyo-Chubu interconnection will be upgraded by 900 MW by fiscal 2020 and plans are being made for a total of 900 MW across the Sakuma and Higashi-Shimizu Frequency Converters. (Total 1,200 MW → 2,100 MW → 3,000 MW). (Figure 41).

Figure 42 shows the transfer capacity of the interconnectors between regions and the average of the forecasted top three maximum electricity demands in each area during daytime in weekdays of August. In light of market splitting, Kitahon Interconnected Line is going to be reinforced by adding 300 MW in 2019. Additional 900 MW will be constructed for the interconnector between Chubu and Tokyo in 2020. Furthermore, interregional transmission line between Tohoku and Tokyo will be strengthened by adding 4, 550 MW in 2027.

4.3.1.2 Planning of cross-regional transmission network

Electric power companies are required to notify their electricity supply plans to METI in accordance with the Article 29 of the Electricity Business Act. OCCTO compiles and submits them to the Minister of Economy, Trade and Industry under the article of the Act.

The electricity supply plan is the ten-year plan formulated every year by electric power companies with regard to installation and operation of electric facilities. Electric power companies submit their supply plans to OCCTO which in turn compiles and notifies them to METI. OCCTO compiles from short-term to mid- and long-term outlooks for electricity demand and supply, development plans of generating sources and transmission lines and submits them with their opinion to METI. Meanwhile, METI can recommend electric power companies to amend their electricity supply plans when they determine that the electricity plan is not relevant for securing stable supply by cross-border power system operation.

OCCTO plays the role of formulating the policy of long-term cross-border power system development and specific development plans. Regarding specific development plans, OCCTO itself can propose the plan. Electric power companies including generating companies can propose their plans, too. There is also a case in which the government committee requests. Therefore, both a regulator and the regulated can propose the plan along with initiative by the government committee in charge of the network.

Taking an example of specific development plans, there is a plan to strengthen the tie between Tokyo and Chubu. This plan was the case requested by the government committee. Specifically, capacities of the frequency converter is planned to increase from 2,100 MW to 3,000 MW in 10 years with the cost of 175 billion yen or 1.4 billion euros (OCCTO 2016c).

The fact that there are two frequency areas in one country is very unique. At the time of the 2011 Earthquake, limited capacity interconnecting two areas aggravated power crisis in Eastern regions. Therefore, the government conducted research on possibility of unifying frequency areas after the Earthquake. The research report concluded that it would cost about ¥10 trillion or €77 billion (ANRE 2012). This cost includes only the cost of replacing the existing turbine generators and transformers of electric utilities. And it would take approximately 40 years to replace generators. There are alternatives to unification of the frequency areas. Installing the frequency converter with the generating facility can be an alternative which will be also costly and take about twenty years. As a result, these two options seem not to be cost effective. Therefore, the realistic option is enhancing converting capability at frequency converter stations.

The transmission and distribution lines are regulated worldwide as they are still natural monopoly. In Japan, this sector had been regulated solely by METI. As a result of deregulation or liberalization, new organizations as described above were established and have been playing the part of regulation on the wire sector. In light of legal unbundling in 2020 and evolution of liberalization, the reform of this sector is under discussion.

4.3.1.3 Network Regulation and Prices of Transmission Services

Traditionally transmission and distribution lines have been regulated based on the cost-of-service. The wheeling system was introduced when partial liberalization of retail sector started in 2000. At the outset of introduction, “pancaking” was permitted. Wheeling rate in each area was the type of postage stamp. Therefore, wheeling through multiple areas was costly for IPPs. Pancaking was abolished for the purpose of promoting competition nationwide in 2005. Current wheeling rate is the license plate type. As one part of the third set of electricity market reform, the Electric Power System Council of Japan (ESCJ) was established in February 2004 to ensure fairness in the use of the general electric utilities' transmission/distribution lines by Power Producer and Supplier (PPS) and wholesale suppliers including independent power producers.

However, the power supply crisis that followed the Great East Japan Earthquake of March 2011 revealed that back-up facilities and arrangements were insufficient to cope with severe supply and demand conditions in the event of a major disaster such as the 2011 earthquake due to constraints on power transmission such as insufficient frequency converter (FC) and insufficient capacity of interregional connector. One reason for this was that the ESCJ's main function was to assist wheeling by incumbents, and authority and responsibility for electric power supply and demand in each electric utility's service were left to the utility concerned. Thus when the 2011 earthquake struck, the ESCJ did not have adequate authority to sufficiently adjust supply and demand cross-regionally.

As a first step in reforming the electric power industry, the ESCJ was replaced by the establishment in April 2015 of the Organization for Cross-regional Coordination of Transmission Operators (OCCTO) in order to promote development of the transmission and distribution networks required to make cross-regional use of generating sources, and to strengthen capacity to adjust supply and demand nationwide in both normal and emergency situations.

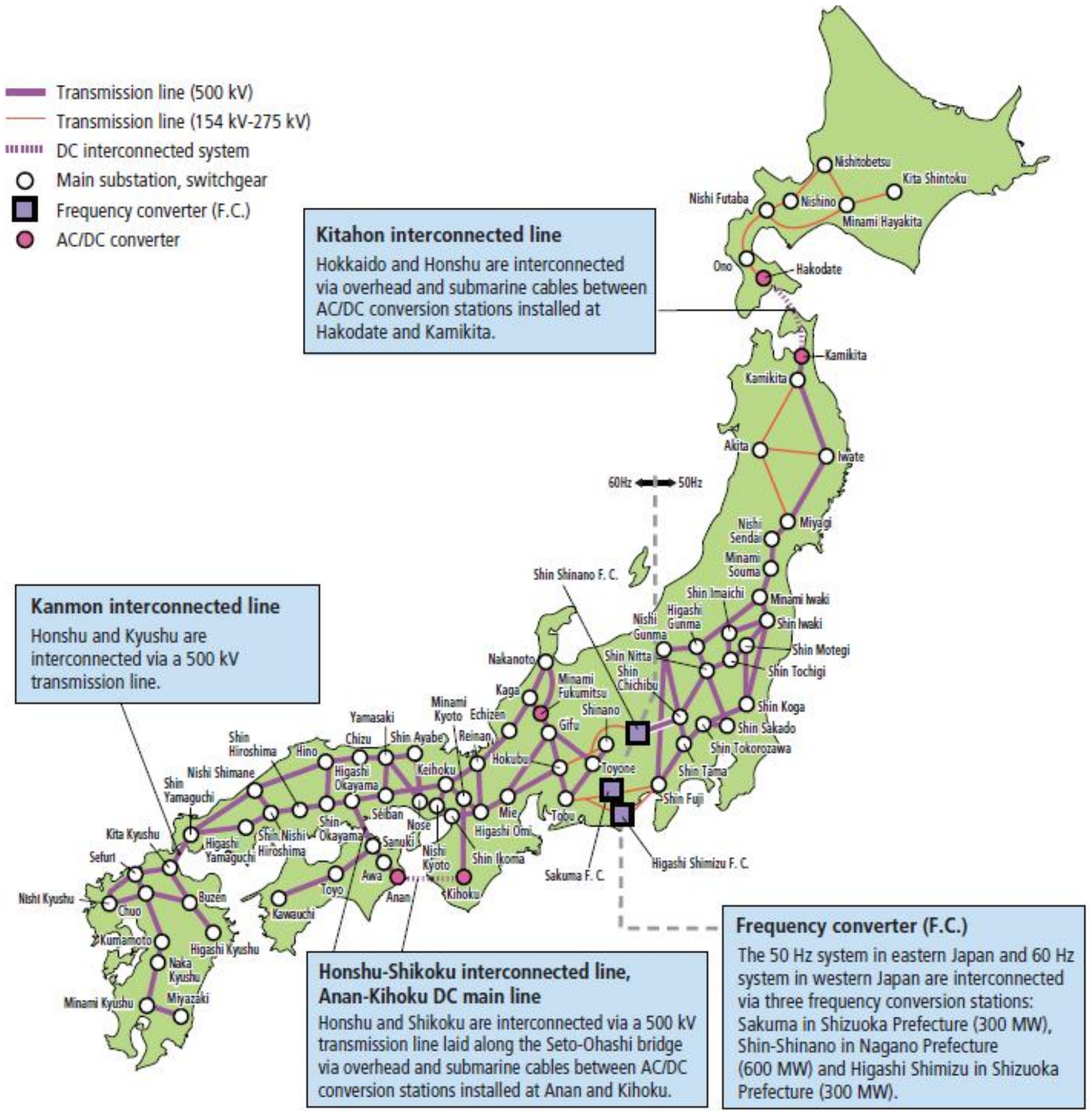
OCCTO's main functions are: (1) to coordinate supply-demand plans and grid plans, reinforce the transmission infrastructure including the capacity of FCs and cross-regional interconnections, and facilitate nationwide grid operation spanning different areas; (2) to coordinate widespread application of cross-regional supply-demand balancing and frequency adjustment by the transmission operators in each area during normal conditions; (3) to adjust supply and demand by instructing that output be increased and electric power shared in case of power shortage due to a disaster or other emergency; and (4) to neutrally perform functions relating to the acceptance of connections from new power sources and the disclosure of grid data.

The Electricity and Gas Market Surveillance Commission (EGC) under the Ministry of Economy, Trade and Industry established in 2015 is also a regulator administering neutrality of networks. The role of EGC is to make suggestions/proposals to the Minister of Economy, Trade and Industry regarding assessment of network tariffs.

4.3.1.4 Status of Utilizing Interconnectors

The individual EPCOs are responsible, in principle, for handling their own system operation and compensate for load fluctuations on their own grids using their own generating sources. However, they do cooperate with each other across different control areas in efforts to improve economic efficiency and ensure a stable power supply by developing optimal power sources, conducting capital investment and exchanging power to benefit from differences in regional characteristics and demand structures.

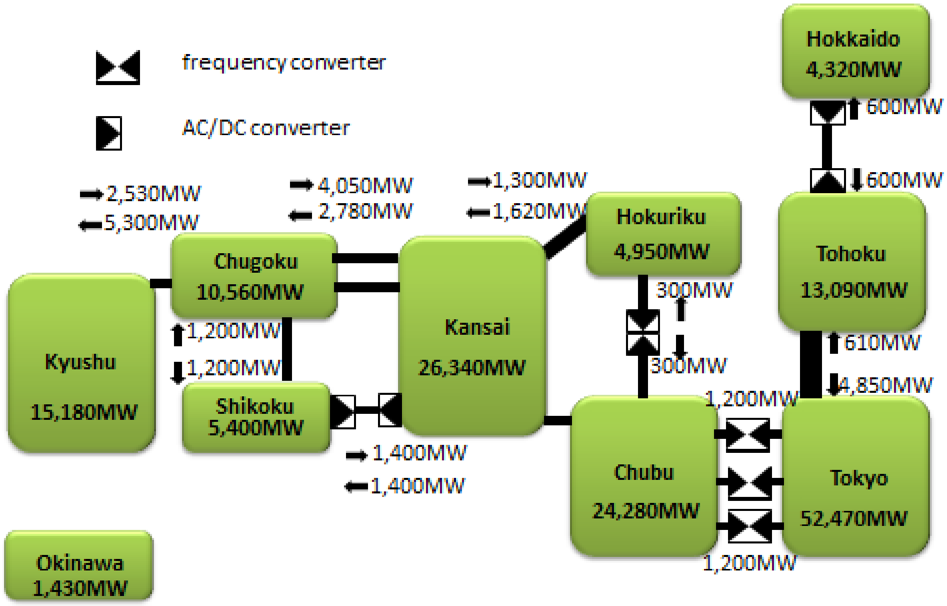
Figure 41 Transmission Line Network in Japan



Source: JEPIC, 2017, p. 42

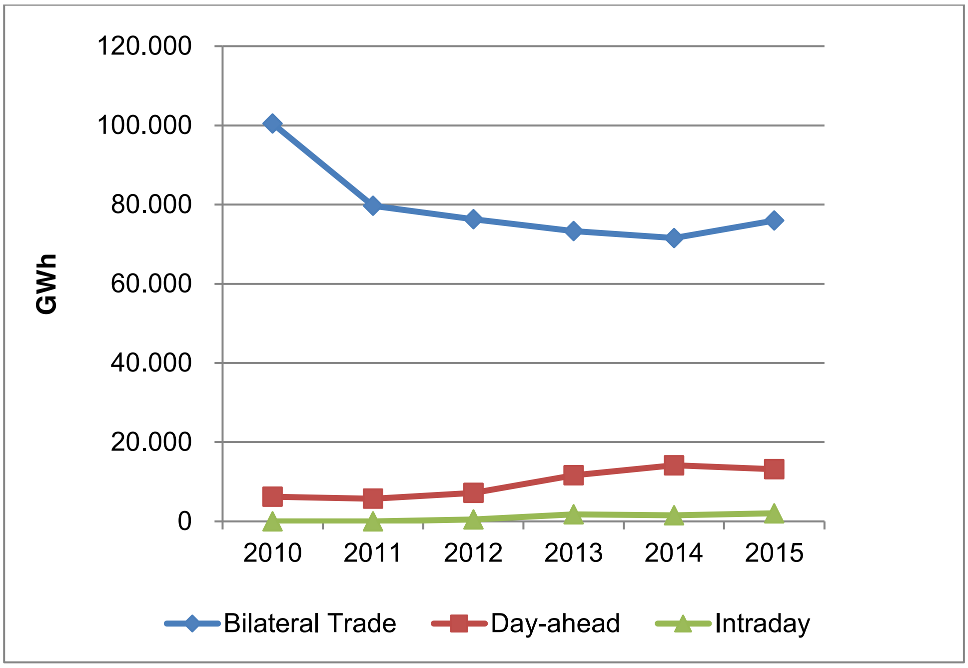
Use of interconnector between regions can be categorized into three types. One is utilizing interconnectors for bilateral trades. Interconnectors are also used for day-ahead and intra-day trading at JEPX.

Figure 42 Transfer Capacity and Maximum Electricity Demand Forecast



Source: OCCTO 2016b, p. 10

Figure 43 Utilization of Interconnectors by Trading



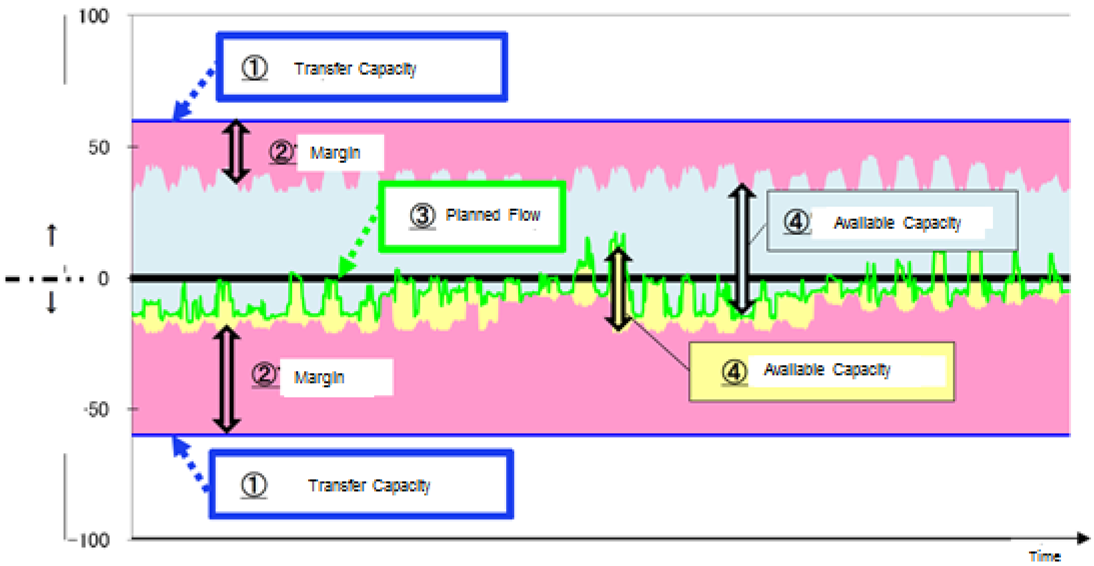
Source: OCCTO 2017, p. 9

Figure 43 shows the trend of each category during the period of 2010 - 2015. As can be seen from this figure, use of interconnectors for bilateral trade is overwhelming. It accounted for 94% in 2010. However, it has been decreasing between 2010 and 2014 (Figure 43). In the day-ahead market the amount of traded electricity has decreased by about ten percent in 2014-2015 but it has doubled in the years before since 2010.

4.3.1.5 Rules Governing the Use of Interconnectors

In Japan the transfer capacity is set for each interconnector. Transfer capacity is defined as the maximum reliable transmission capability that does not damage transmission facilities. Figure 44 shows the composition of the transfer capacity. Margin is the capacity reserved for emergencies such as tight demand and supply and extraordinary situation of the power system. Planned flow is total of the capacity which users of interconnectors registered. Available capacity is the balance.

Figure 44 Composition of the Transfer Capacity



Source: OCCTO 2017, p. 10

Allocation of the transfer capacity has been so far on first-come first-serve basis. The transfer capacity is at first allocated to bilateral trade between entities. Those who conduct bilateral trade apply for use of interconnectors necessary for bilateral trade. For wide-area trading through spot markets at JEPX, entities can make use of the available transmission capacity. Therefore, it can be said that priority has been given to use of interconnectors for bilateral trade. If some interconnector is occupied by bilateral trade, then current system does not allow wide-area trading through JEPX.

Table 15 is the example of registered transmission flow between Tohoku area and Tokyo area. There are two-way flows. One is from Tohoku to Tokyo and another being opposite direction. Given the transfer capacity, conventional thermal, hydro and nuclear power plants use up most of the transfer capacity between 2017 and 2024 based on bilateral contracts. In particular, available capacity from 2019 to 2021 is going to be zero according to this plan. If actual use of the interconnector follows planned use, then available capacity for other uses does not exist. However, actual use will be different subject to the operating status of each power source.

Table 15 Registered Flow between Tohoku and Tokyo

Generating Source	Flow	2017	2018	2019	2020	2021	2022	2023	2024
Thermal	Tohoku ->Tokyo	283	286	346	346	322	318	318	317
	Tokyo ->Tohoku	-47	-47	-47	-47	-47	-47	-47	-47
	total	236	239	299	299	276	271	271	270
Hydro	Tohoku ->Tokyo	49	49	49	49	49	49	49	49
	Tokyo ->Tohoku	-33	-33	-33	-33	-33	-33	-33	-33
	total	16	16	16	16	16	16	16	16
Nuclear	Tohoku ->Tokyo	97	97	97	97	206	206	206	206
	Tokyo ->Tohoku	-76	-76	-76	-76	-76	-76	-76	-76
	total	20	20	20	20	129	129	129	129
Others	Tohoku ->Tokyo	78	88	82	82	66	66	66	66
	Tokyo ->Tohoku	-2	-2	-2	-2	-2	-2	-2	-2
	total	76	86	80	80	64	64	64	64
All Generating Sources	Tohoku ->Tokyo	507	520	573	573	643	638	638	637
	Tokyo ->Tohoku	-158	-158	-158	-158	-158	-158	-158	-158
	total	349	362	415	415	485	480	480	479
Margin	Tohoku ->Tokyo	85	85	85	85	85	85	85	85
Available Capacity		66	53	0	0	0	5	5	6
Transfer Capacity		500	500	500	500	570	570	570	570
Source: OCCTO, Planning Process pertaining to Tohoku-Tokyo Interconnector, August 24, 2015									

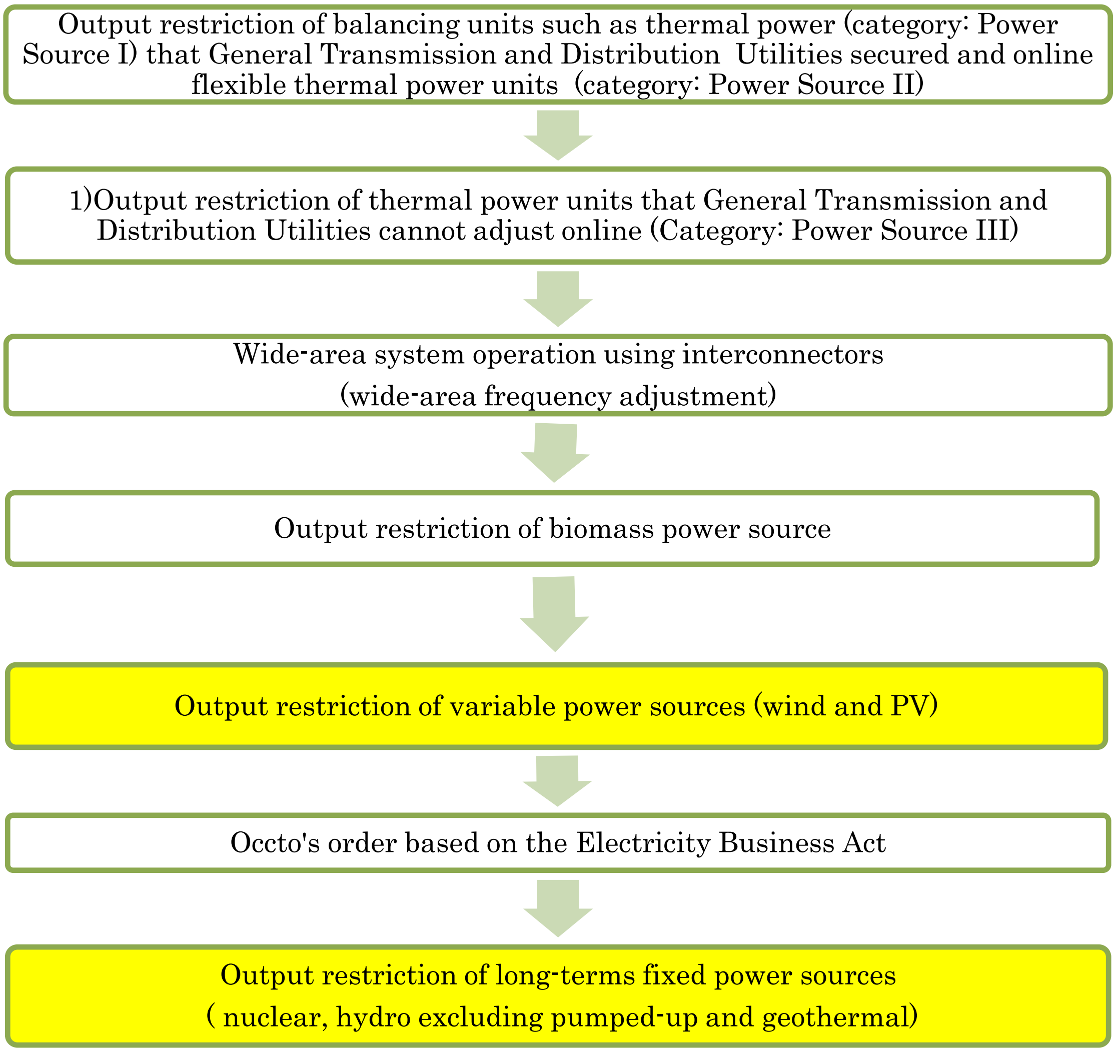
Source: OCCTO 2015

4.3.1.6 Access Rules and curtailment

As it was mentioned in section 3.1.1.3, there is a definite set of rules governing the order of output restriction for capacities in case of network restrictions. Figure 45 shows that nuclear, hydro and geothermal power should be the last to restrict output.

Access to the grid has been also on first-come first-serve basis. Therefore, those who have already accessed to the grid are given priority regardless of the type of generating power plants including renewable energies. Unlike dispatching, current first-come first-serve basis does not guarantee priority access by renewable energies. Instead, “connectable amount” is stipulated for each transmission and distribution utilities.

Figure 45 Rule of Output Restriction



Source: ANRE 2015b

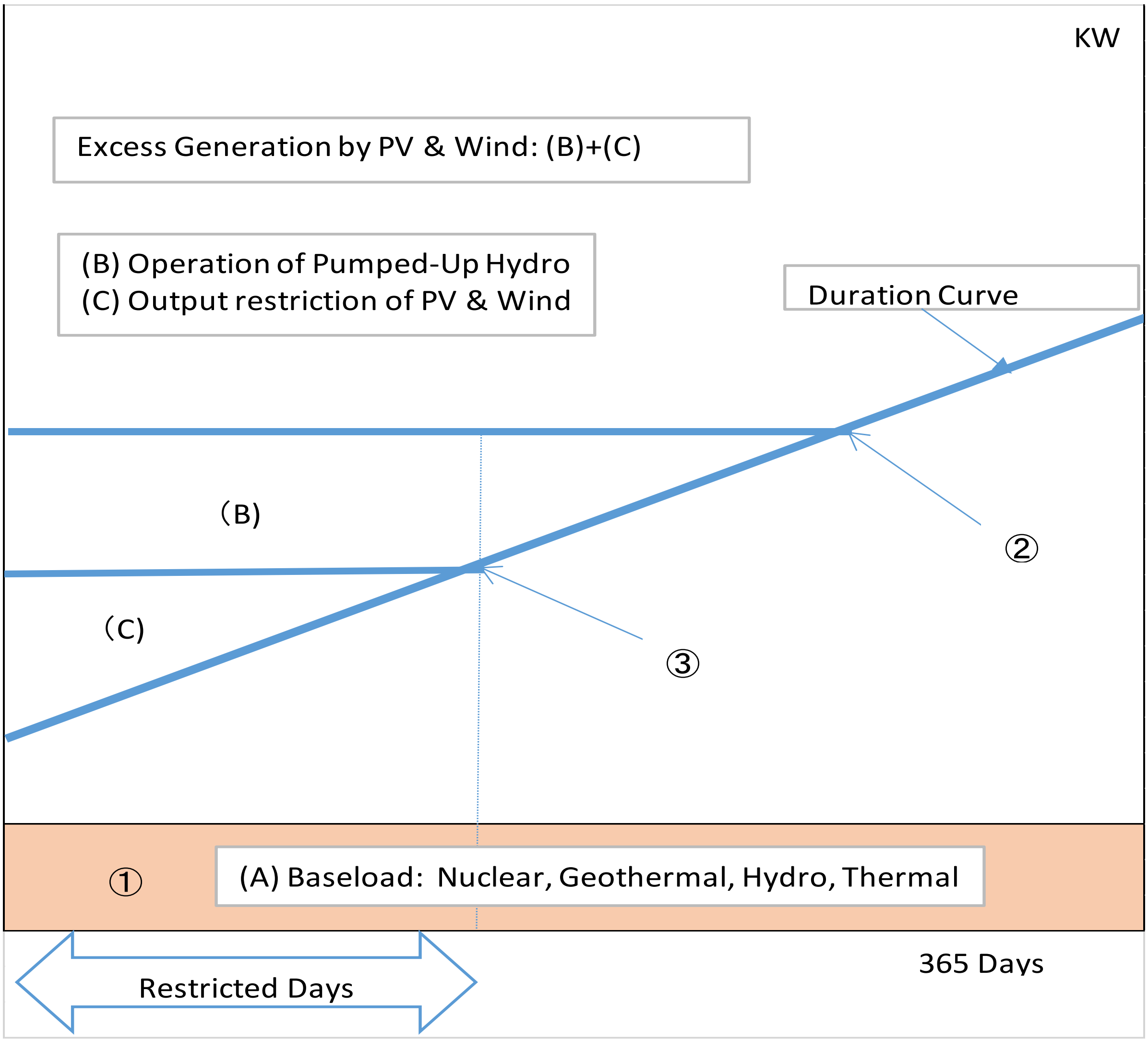
Connectable amount of renewable energies for each transmission and distribution utilities is derived by taking into consideration following steps (Figure 46).

① When output of wind and solar is high, generation level by thermal power units is kept lowest.

② If electricity supply exceeds demand even after ramping down output of thermal power, then excess generation is absorbed as much as possible with operating pumped-up hydro power plants.

③ Even after step ②, if excess generation is not eliminated, then utilities will trigger the rule for restricting output of renewable energies. The rule stipulates that output is restricted up to 30 days or 320 hours for PV and 720 hours for wind annually without compensation.

Figure 46 Calculation of Connectable Capacity



Source: ANRE 2016a

METI organizes meeting of the Grid Working Group (WG) of New and Renewable Energy Subcommittee every year and examines the connectable amount in the area of each power company. It is an output restriction of up to 30 days or 360 hours for PV and 720 hours for wind that is certified under the feed-in tariff (FIT) policy and based on the electricity demand and the composition of generating sources. Connectable amount determines the connectable capacity of PV and Wind considering supply-demand balance.

Capacity reserve for 30 day output restriction and connectable amount in 2016 is shown in Table 16. As indicated in the table, amount of 30-day restriction is more than connectable amount except the case of Shikoku's wind. This is mainly because electricity demand has been lower than forecast. And it is notable that Hokkaido has no connectable capacity for both PV and wind. Hokkaido is facing serious shortage of balancing units. Therefore, use of batteries is now in consideration.

Table 16 Capacity reserved for 30-day output restriction and connectable amount

		Hokkaido	Tohoku	Hokuriku	Chugoku	Shikoku	Kyushu	Okinawa (MW)
PV	30 day restriction	1,170	5,520	1,100	6,600	2,570	8,170	495
	connectable amount	0	5,440	910	6,160	2,410	7,950	470
Wind	30 day restriction	360	2,510	590	1,090	640	1,800	183
	connectable amount	0	2,460	500	0	710	1,680	172
Minimum Load		2,877	7,606	2,530	5,619	2,545	8,247	720

Source: METI 2016

4.3.2 Germany

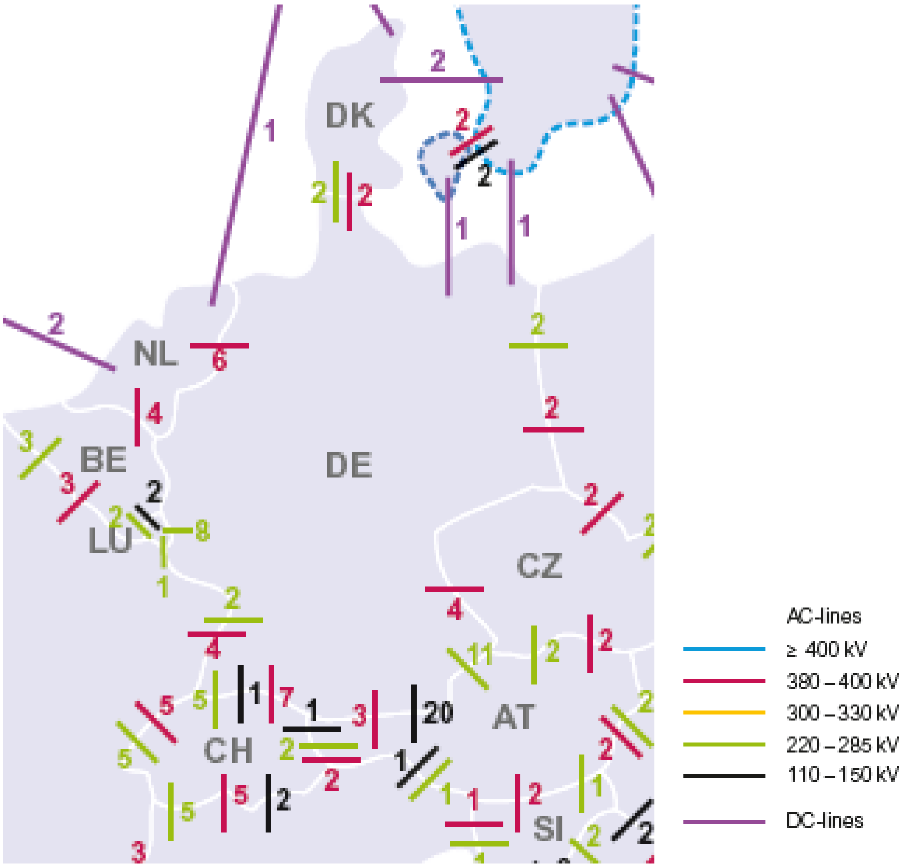
4.3.2.1 Network system and network planning

In Germany there were 875 distribution system operators (DSO) and 4 transmission system operators (TSO) in 2016 (BNetzA und BKartA 2016, p. 31). The transmission grid is divided in 220 kV and 380 kV (maximum voltage) whereas the distribution grid is divided in 400V (low voltage), 20kV (medium voltage) and 110kV (high voltage) grids. As noted in section 3.1.2.2, Germany is connected to neighboring European countries via transmission lines and is trying to improve these connections via increasing transmission capacity and harmonizing institutional arrangements in the framework of the European target model.

The four TSO's coordinate their maximum voltage grid planning in Germany with the grid development plan (Netzentwicklungsplan, NEP) that is updated on a rolling basis. The planning is based on a scenario framework that has to be approved by the federal network agency (BNetzA). The NEP-development includes a participation process (NGOs, local initiatives, individuals etc.) and the current version of the plan is in the stage of the second draft and reaches until 2030 (50Hertz et al. 2017b). In addition, the German grid planning is coordinated with the Ten-Year Network Development Plan (TYNDP) of the European Transmission System Operators for Electricity (ENTSO-E), the European TSO's roof organization (ENTSO-E 2016b).

As was also mentioned in section 3.1.2.2, Germany is a member of the Pentalateral Energy Forum that deals with the technical details necessary to implement the European target model within the central Western regional electricity initiative (PLEF 2007, 2015b). However, due to its central location, German is member of various electricity regional initiatives.

Figure 47 Cross-border transmission lines (as of end-2016) in Germany



Source: ENTSO-E 2017b, p. 16–17

4.3.2.2 Network regulation and RES-integration

Of the 875 DSOs in 2016 798, or around 90%, had less than 100,000 customers connected to their grids. Therefore, they fall under the de-minimis rule mentioned in section 2.2.2.2 and are not forced to unbundle. That is, traditionally there is a decentralized structure in Germany in terms of the DSOs. Historically, the DSOs are mostly municipal utilities. In most cases network operation is carried out by a separate network company although utilities with less than 100,000 (§ 7 subsection 2 EnWG). However, the 10% that do fall under this rule represent the large DSOs that together supply 77% of all meters (§ 7 EnWG; BNetzA und BKartA 2016, p. 32).

The underlying principle behind the Incentive Regulation Ordinance is the so-called revenue-cap regulation meaning that the grid operator's revenues rather than their costs is regulated. Based on historical costs the regulatory agency sets a revenue cap for a 5-year-period resulting in a budget for investments into the grid as well as for profits to the network owners. After 5 years the revenue cap is adjusted. This budget approach is meant to create an incentive to lower the costs during the regulatory period by allowing distribution system operators to retain some of the efficiency gains. A second efficiency incentive is implemented by an efficiency benchmark between the network system operators (Matschoss et al. 2017).

Due to the energy transition and related higher share of decentral renewable infeed, the network situation for some DSOs changes since wind and solar potential as well availability of suitable sites are concentrated in some mostly rural areas. Most wind turbines are concentrated in the north of Germany since there are the best wind sites whereas PV power plants are mostly installed in the south of Germany (BNetzA und BKartA 2013, p. 26–27). Due to these different regional concentrations of RE DSOs face different challenges for the future. Furthermore, the sizes of DSOs and the structures of their network areas vary quite strong so that integration tasks are network specific (Bayer et al. 2017). There is a small number of around 20 DSOs that is especially affected of RES expansion as 80% of the total RES capacity is connected to their network areas (Moser 2013, slide 6). According to a study on behalf of the German federal ministry of economics, 39% of the required high voltage grid expansion (110 kV) is concentrated in the north of Germany (Büchner et al. 2014, p. 43). In addition to that, the authors state that although only 8% of low voltage grids (0.4 kV) and 35% of medium voltage grids (1 kV – 30 kV) face a need for network expansion, 39% of low voltage network operators and 64% of medium voltage network operators are affected by grid expansion with is almost exclusively required in rural areas (Büchner et al. 2014, p. 47). This on the one hand makes clear that the requirement for distribution network expansion is concentrated in a limited number of areas and on the other hand shows the occurrence of structural differences even within a distribution network of one operator.

In order to enable a faster network expansion to integrate RES into the grids there was a regime change in 2016 to enable a quicker cost pass-through of capital costs (BReg 06.06.2016, pp. 23–24) coming into effect from 2019 on (i.e. after two regulatory periods) and influencing the revenue perspectives of DSOs (Schröder 2017, pp. 8–12). The quicker cost pass-through is particularly welcome for those DSOs with high investment needs (Schröder 2017, pp. 11–12) but it lessons incentives for efficiency since the budget mechanism has been given up. In parallel, the regulated return on investment has been lowered and it remains to be seen what effect has the larger impact (Matschoss et al. 2017).

4.3.2.3 Access rules and curtailment

As noted in section 2.2.2.2 regulated grid access and an incentive regulation was introduced following the 2005-revision of the EnWG, leading to the “ordinance of incentive regulation” (Anreizregulierungsverordnung, ARegV) entering into force in 2007 (BNetzA 21.1.15, p. 41; Boltz 2013; Brunekreeft und Bauknecht 2006, p. 247). Furthermore, transmission and distribution are required to be unbundled from electricity production since then, leading to stricter unbundling rules for TSOs during the third liberalization wave in 2011.

For renewable energies priority grid access was introduced with the EEG 2000 already (see section 4.2.2.2.2), i.e. at a time when the negotiated market access (see section 2.2.2.1), was still the common regulation. Priority grid access implies that the costs of connection to the next connection point are borne by the operator of the new capacity whereas the costs of reinforcement of the network are borne by the network operator who, in turn, pass these through to the electricity consumer (Matschoss et al. 2017; EEG 2017, § 8).

As noted in section 4.2.2.2.6, as of 2017, in so-called 'network expansion areas' new wind capacity under the auction scheme is limited to 58% of the average capacity that has gone into service in the years 2013-2015. This shall reduce grid congestion and curtailment of renewable energies which was introduced with the EEG 2009 and allows grid operators to curtail renewable capacities in case of grid congestion (see also section 4.2.2.2.4). As noted, the first network expansion area is located in Northern Germany, expands all across the coast line of the North Sea and the Baltic Sea and is valid until 2020.

5 Business models for energy transition

5.1 Japan

Liberalization of the household sector triggered various entities to enter the electricity market. The notable new participants in the market are municipalities. Retail power companies associated with municipalities are increasing. The number of retail power companies funded by municipalities stands now at 18 (Figure 48). Involvement of municipalities can play an important role to secure demand at public facilities, power sources such as refuse-fired power generation and mini-hydro power generation, trust from customers and financing. For instance, Narita Katori Energy is the first joint municipal entity established by Narita City, Katori City and Koyo Denki. Koyo Denki is a private company chosen by public solicitation as a partner of two cities. Each city holds 40% of stocks and 20% is held by Koyo Denki.

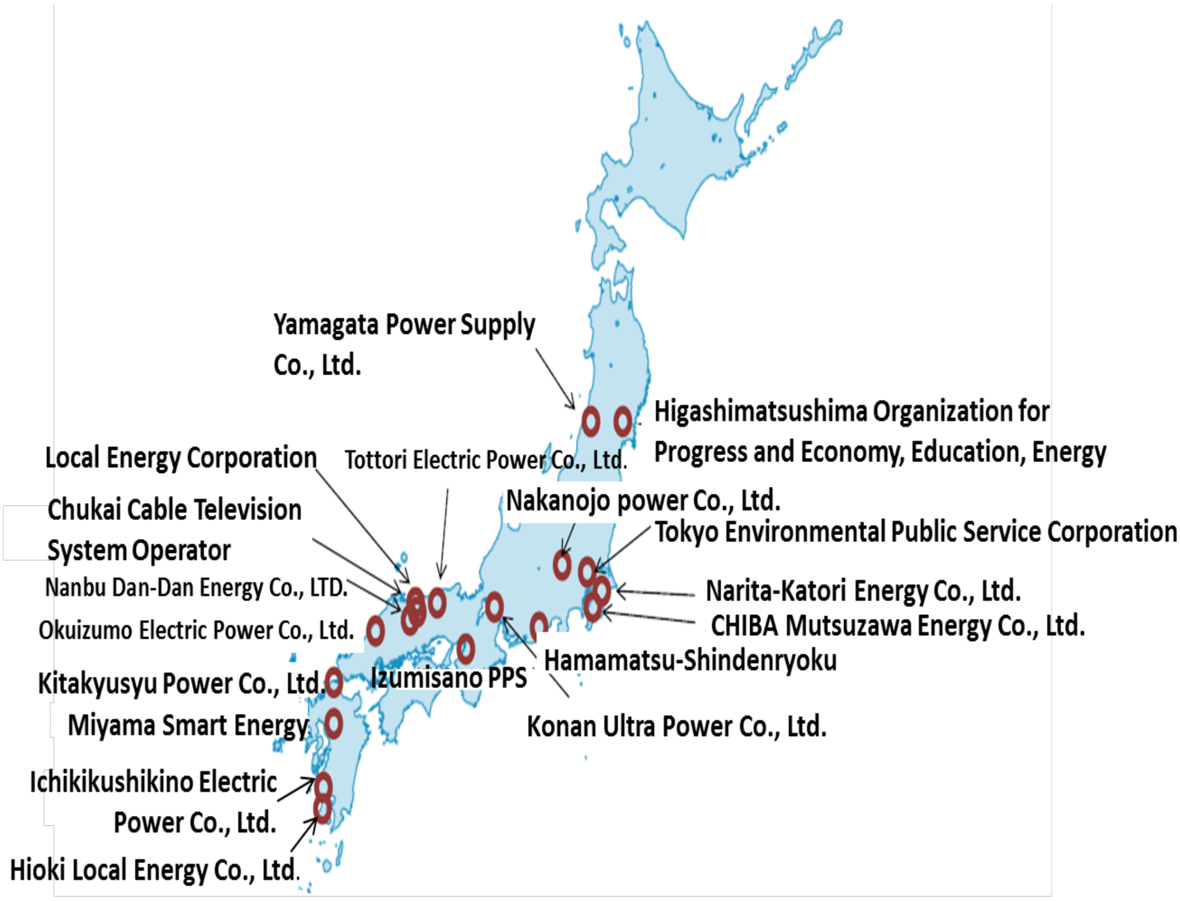
Another model is to form the balancing group with multiple retail companies. The larger the balancing group, the smaller the risk of imbalance. There are also companies specializing in supply and demand management commissioned by retail power companies. These companies also support retail power companies in terms of analysis on viability of projects and planning.

New participants engaging in demand response are also entering in the market as negawatt transaction has begun in April 2017. EnergyPool as the entity of a virtual power plant (VPP) has made demand response contracts with Tokyo Electric Power Grid and Kansai Electric Power Company. VPP is a promising area as distributed resources are expanded. A consortium formed by major companies including Kansai Electric Power Company started the VPP's demonstration project under the auspices of Agency of Natural Resources and Energy.

System solution companies like Kanden System Solutions are affiliated with incumbents like Kansai Electric Power Company. Fujitsu is also enlarging supporting services to new electric retail companies. Kanden System Solutions are selling the customer management system and has also provided consulting services with regard to start-ups and improvement of operation of retail business to 30 companies. This company has even published a book covering know-how of electricity retail business.

New businesses using internet of things (IoT) are also emerging. Tokyo Electric Power Grid, Hitachi and Panasonic formed the alliance to establish an IoT platform to collect, accumulate and process information such as the status of electricity use and temperature inside about 100 residences. GE, Siemens and Mitsubishi Hitachi Power Systems have been working on improving efficiency of generating plants with making use of IoT. GE's Predix Machine has been developed to optimize operation of generating equipment such as auxiliary equipment. Predix Cloud has been developed to realize optimum operation of a generating plant as a whole and as one of such applications.

Figure 48 Municipal Retail Power Company



Source: EGMSC 2017b, p. 155

As the above-mentioned, digitization is reaching into the corner of the electric power industry in Japan. Big data, IOT and Artificial Intelligence (AI) have potentials to strengthen the competitiveness and solve challenges confronting the industry. Digitized technologies are being applied not only to the generating sector but also the transmission/distribution lines and the retail sector. One example in the transmission sector is a self –propelled robot that moves along extra-high voltage transmission lines to examine their external surface conditions and measure their outer diameter. Currently, inspection of overhead high-voltage transmission lines is performed as an aerial inspection by workers or carried out visually using binoculars or helicopters. However, aerial inspection requires personnel to walk on the cables as they perform the inspections. This entails a tremendous amount of labor and time, and also requires the transmission of electricity to be stopped. HiBot Corp, venture business, has developed the self-propelled robot called Expliner in cooperation with Kansai Electric Power Company, J-Power System Corporation and Tokyo Institute of Technologies. This technology is expected to be sold domestically and overseas.

Another example is the life support service utilizing data pertaining to electricity consumption. KDDI which is the telecommunication company and Kuwana City has started life support service for the aged and other services including energy conservation advices with using big data collected from 14 thousand households in the nation. Statistical analysis using big data makes it possible to give the advice which fits each household by inferring attributes of the household including life styles (ANRE 2017a).

5.1.1 Business models from the first set of reforms to 2011

In this section, we will describe business models in Japan. It should be noted that Japan's liberalization started in 1995 when the first set of reforms was implemented (section 2.1.2). Then, retail sectors have been liberalized step by step and a class of small customers including the residential sector was liberalized in April 2016. As a final step, legal unbundling and market reforms such as establishing new markets like the baseload market are also expected to be enforced in around 2020. However, it can be said that there was no fundamental industry restructuring for almost two decades in the system established in the post-war era since 1995. The structure governed by regional electric utilities with vertically integrated supply systems remained intact in substance until just recently.

Table 17 Players and their business areas before 2011

Player	Sectors	Activity
10 vertically integrated electric utilities	Generation, transmission, distribution and retail	Generation, transmission, distribution, retail supply
Wholesale electric utilities	Generation and transmission (J-Power)	Generation, wholesale
Wholesale supplier	Generation	Generation, wholesale
Specified-scale electricity suppliers	Generation and retail	Generation, retail supply
Special electric utilities	Generation, transmission distribution and supply	Retail supply using own generation and wires
autoproducers	Generation	Generation and consumption by their own

Source: own depiction

We see real restructuring on the horizon triggered by the aftermath of the nuclear accidents in 2011. Various players are entering in segments of the electric power industry, especially after key institutional changes as legal unbundling and full retail liberalization were decided. With the background of the above-mentioned, we will at first describe activities of major players before 2011. Table 17 shows major players and sectors involved.

5.1.1.1 Incumbents (10 vertically integrated electric power companies and wholesale utilities)

As of March 2011 when the Great East Japan Earthquake hit, total installed capacity in Japan excluding autoproducers and public power was 228GW. 10 regional electric utilities accounted for 90%. J-Power and Japan Atomic Power Generation (JAPG) which are wholesale electric utilities which sell electricity generated to regional electric utilities. J-Power and These wholesale utilities own about 20GW and have long-term bilateral contracts with ten vertically integrated electric power companies which had been called the General Electric Utilities (GEU) before the license system was introduced in 2016. There are also publicly-owned hydroelectric and joint thermal power companies established jointly by GEUs or GEU and other industries as wholesale electric utilities. Public power and joint thermal companies own around 20GW of which 2GW is hydro owned by public power. Wholesale suppliers are electric utilities which supply electricity to GEU with contracts to supply a volume in excess of 100 MW for five years or longer.

5.1.1.2 Specified-scale Electricity Suppliers and Special Electric Utilities as New Participants

Specified-scale electricity supplier is also called power producers and suppliers (PPS). These suppliers are utilities to supply electricity using the wires owned by GEU to high-voltage (6kV) or higher voltage customers with the contract demand of 50kW or above. Special electric utilities are those utilities who own their generating plants and the wire to supply electricity to meet demand in specified service areas. The number of PPS as of March 2016 was 799 and their supply was 40TWh or less than 4% of total production in fiscal 2015. The Generating capacity owned by special electric utilities was only 264 MW. These players were born by liberalization but their roles were very limited.

5.1.1.3 Network operators, meter reading and billing

GEUs own transmission and distribution lines and were responsible for balancing demand and supply within respective regional area. In the 3rd set of reforms (see Table 2), accounting separation between transmission/distribution sectors and other sectors were implemented to warrant fair access by new entrants to GEU's wires and transparency. Pancaking was also prohibited in the 3rd reform.

In Japan, transmission and distribution remain bundled even after legal unbundling is enforced. Metering which can be potentially competitive sector will also remain bundled with the network in the case of Tokyo Electric Power Company. Regarding billing, TEPCO Energy Partner which is retail company commission billing business to TEPCO Power Grid which is transmission and distribution company.

5.1.1.4 Trade

As can be seen from section 2.1.3.1 the wholesale market represented by JEPX is very shallow market as incumbents did not make use of this market positively. This was because they had sufficient supply sources and bilateral contracts to meet electricity demand. As a result, the share of trade volume in total electricity supply in Japan remained only a few percentage.

5.1.1.5 Investor

Traditionally, the capital structure of incumbents was based on long-term debt rather than equity. The share of bond and bank’s loan was much higher than stocks. With monopolized market, incumbents were allowed to procure the fund with low costs of capital in the financial market. With coming full-fledged competitive market, this system will be also changing.

5.1.2 Business models after the Electricity System Reform

As Table 3 in section 2.1.2 shows, market operators have been categorized into five types. Regardless of changes in the category, however, former vertically integrated regional electric utilities will continue to be dominant players in the foreseeable future. Meanwhile, many new participants are beginning to enter in the market for power. Table 18 shows players and activities.

Table 18 Market players and their business areas after the system reform

Player	Sector	Activity
Unbundled 10 vertically integrated electric utilities	Generation, retail	Generation, retail including retail in other areas
Network operator of unbundled 10 vertically integrated electric utilities	Transmission, distribution	Network operation, metering & billing, purchasing RE
Generators	Generation	Generation (wholesale and retail supply)
Transmission operator and specified transmission and distribution operators	Transmission and distribution	Transmission to general transmission/distribution operators, transmission & distribution to specified supply points
JEPX	Trade	Trading (including negawatt)
TBD	Trade (capacity, environmental value)	Trading
Retailers	Retail	Retail supply

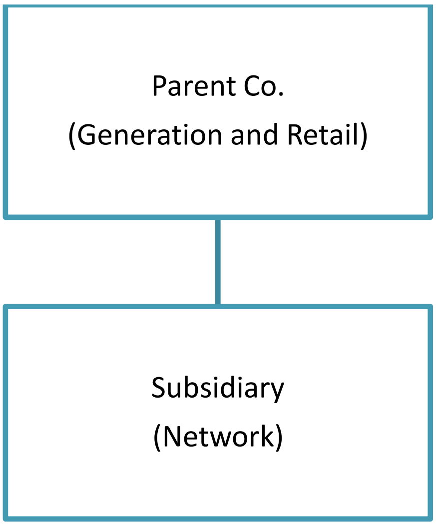
Source: own depiction

5.1.2.1 Unbundled incumbent's generation and retail

Incumbents are scheduled to unbundle by 2020. TEPCO has already unbundled the structure and established the holding company and three separate companies as Figure 4 in section 2.1.2 shows. Other vertically integrated electric utilities are likely to organize the structure differently. There are two types as unbundled system. One is the system which TEPCO adopted. Another one is the structure as the Figure 49 shows. Most of vertically integrated electric utilities seem to adopt this structure. The reason is that owning both generation and retail sector is expected to strengthen competitiveness, which is a lesson learned by precedent cases in the competitive electricity markets overseas.

After the legal unbundling, the next stage of restructuring is expected. As a matter of fact, restructuring has already started. Consolidation of thermal power sectors of TEPCO and Chubu is an example. JERA (Japan's Energy for a New Era) was established in 2015 by TEPCO Power and Fuel and Chubu Electric Power Company. Their value chain covers from upstream fuel investments to overseas power generation and infrastructure. If consolidation is completed, JERA's thermal power capacities and annual LNG procurement will amount 73GW and 40 million ton, respectively (TEPCO 2017).

Figure 49 Parent company and subsidiary



Source: JEPIC/own depiction

5.1.2.2 Network operator of unbundled 10 vertically integrated electric utilities

Transmission and distribution lines will be literally unbundled by 2020. The network operator will prohibited from engaging in generation and retail businesses from 2020. Consolidation of the network operators is likely in the future. If consolidated, then possible direction is to establish a nation-wide network organization like the independent system organization or the independent transmission operator.

5.1.2.3 Generators

There are more than 450 generating companies (section 2.1.3.1). However, the number of generating companies with more than 100MW is 88. Incumbents including former wholesale entities have overwhelming share of generating capacities. To bring about the competitive market, divestiture is one way. There were precedents overseas. However, this option was not considered at least officially in the discussion about the electric market reform. As a result, asymmetrical regulation have been naturally applied to incumbents. Rather, direction is consolidation of the industry to compete in the international market for power.

5.1.2.4 Transmission and distribution operators

There are only two entities categorized as a transmission operator. One is J-Power which is a major utilities specializing in generation and transmission. Another is North Hokkaido Wind Energy Transmission Corp (NHWET) established by wind developers and financial institutions. Wind resources are endowed richly in the Hokkaido area. To harness them, NHWET is going to build transmission lines which will be the first merchant transmission line.

Specified transmission and distribution operator is another type. These operators are those who supply electricity to demand at the specific point. There are 20 entities registered as specified transmission and distribution operators.

5.1.2.5 JEPX and other markets

Wholesale trade in Japan consists of bilateral trade and trading at JEPX. As we discussed in section 2.1.3.1, liquidity at JEPX is very low. Therefore, various measures are being introduced to activate the wholesale market. In addition, various new markets such as the baseload market and capacity are to be established (section 4.1.1.1).

5.1.2.6 Retailer

Many retail power companies have already entered the market (section 2.1.3.2). As the number of new participants increase, business models get more diverse. The share of incumbents‘ retail still accounts for more than 90% (section 2.1.3.2). However, it appears that the share of new participants is gradually increasing overall. In particular, competition for acquiring customers in metropolitan areas among incumbents is getting fierce, which never occurred before full liberalization in 2016.

Generally, large customers are elastic to changes in electricity rates. Therefore, the switching rate is much higher than residential customers in every country. Meanwhile, switching rate in a class of small customers is commonly low. There are several reasons for low switching rates. Price elasticity is low because the share of electricity bill in income is quite low. Substitute for electrical energy does not exist for many applications, which is another reason. Needless to say, electricity is a necessity goods for all too.

5.1.2.7 Investors

In the traditional electricity supply systems, the rate of return was guaranteed by cost-of-service regulation to secure the fund to build facilities to meet increasing demand. However, in the competitive market for power, there is no guarantee to recover investment through regulated electricity rates. Risks associated with business in competitive sectors will be definitely increasing so that cost of capital will naturally get higher. Mega banks and institutional investors including insurance companies as major investors will continue to provide the fund to incumbents. However, terms and conditions for financing will be much tougher.

5.2 Germany

The main focus of this chapter lies on business models of different existing and new actors in the German power sector. The business models described in this chapter enable financial participation in the power system for the respective actors and investors. The latter may also come from outside the power system (see below). Besides financial participation there are other possibilities of participation of various stakeholders, such as inclusion in planning processes, public consultation of network planning etc. However, this report focuses on financial / business participation possibilities[14]. In order to enable new actors to take part in the markets, next to the most important condition which is non-discriminatory network access (see chapter 2.2.2) transparency is one quite important prerequisite: For generation, wholesale markets, control reserve markets, metering as well as the regulated network area, this is achieved by the publication of market and other data from energy exchanges (EEX 2017d), TSOs (50Hertz et al. 2017c, 2017a, 2017d), the Federal regulatory authority (e.g. § 31 ARegV) in co-operation with the Federal cartel office (BNetzA und BKartA 2016), DSOs (e.g. § 17 StromNZV; StromNEV, S. § 27). Still, for the regulated network areas some deficits are prevailing as far as transparency is concerned (cf. Canty 2015).

In this chapter, at first, the actors and their business models in an early stage of liberalization of the power sector are shortly described. After that, the focus is shifted towards the situation nowadays as well as opportunities for new actors and business models that are emerging in the German power system. The description of the actors in the power system is made in the order of the value-added steps of the power system. There are some actors that are active on more than one value-added step and hence are described at first. Since the energy transition can be characterized as a dynamic process, no claim to completeness can be made here.

5.2.1 Business models in the previous energy system

In this chapter, the business models of key actors in the energy system in an early phase of liberalization are considered. Hence, the time frame ranges from approximately 1998 until between 2005 and 2009 (see chapter 2.2.2 for a more detailed overview on the liberalization process in Germany). In order to match the description with the prevailing conditions for each of the value-added steps of the power system, these are briefly described (see Leprich 2012b for the following):

- Investors: In the considered phase of liberalization RES shares were quite low compared to nowadays (much less than 20 %), but steadily growing (see BMWi 2016f, p. 5). Investors that invested in renewable capacity ranged from private persons, depending on the kind of energy source organized in companies or as minority shareholders, to ESCOs and institutional or strategic investors (Leuphana Universität Lüneburg und Nestle 2014, pp. 7–20). Investments in

[14] For other participation possibilities please refer to strategic Topic 2: “Strategic Framework and Sociocultural Aspects of the Energy Transition”

conventional capacity was made mostly by the established four big vertically-integrated utilities as well as municipal utilities.

- Production: In the past, there was a quite high market concentration as far as market shares of production capacity and power generation are concerned. Power generation was mostly centralized and most conventional power plants were no cogeneration plants.
- Network operation: Networks had to manage mostly unidirectional power flows from higher to lower voltage levels. There was only few need for grid expansion as grid structures had historically evolved.
- Trading: In the early phase of liberalization power wholesale markets as well as power exchanges had just started their activity and were still in a setup process. The product range of energy exchanges was smaller and interconnector capacities with neighbor states were lower than nowadays. There was much less activity in the internal European electricity market as it was just emerging. Trading activity mostly had a long-term focus (futures and options market) as utilization of conventional capacities was long-term oriented.
- Supply: In the distribution segment there was quite low competition since mostly vertically-integrated utilities were active in this segment. As network owners they had the possibility to erect market barriers and discriminate third party competitors through high network charges which they made use of.
- Metering: In the past metering activities were exclusively organized by distribution system operators. Mostly standard metering infrastructure was used. After unbundling this area from network operation, at first, competition was low.
- Overall Trends: Despite liberalization there was a trends of further centralization of the ownership structure in the wholesale market.

Table 19 provides an overview on the actors and their core business activity of the energy system in the early liberalization phase which are described below.

Table 19 Actors and business activity in the energy system of the early liberalization phase

Actor	Value-added step	Core business activity / main interest
The "big four" vertically-integrated utilities	Generation, TSO, DSO, supply	Conventional power generation, network operation, supply / no full unbundling to secure competition advantage
Municipal utilities	(Generation,) DSO, supply	Conventional power generation, network operation, supply, other sectors / no full unbundling to secure competition advantage
Transmission system operators and distribution system operators	TSO, DSO	Network operation; no full unbundling / no full unbundling to secure competition advantage
Decentral power plant operators	Generation	Renewable or CHP power generation / maximize production
Industry and other final customers	Consumption	Consumption / minimization of energy procurement costs

Source: own compilation

5.2.1.1 "The big four" vertically-integrated utilities

As pointed out in section 2.2.2.1 the so-called "big four" vertically-integrated utilities E.ON, RWE, Vattenfall and EnBW in the past had quite high market shares in power generation. In 2007 and 2008 more than 80% of total power generation capacity was owned by these companies and they accounted more than 80% of total power generation (Bundeskartellamt 2011, p. 18). Their power generation units were mostly large-scale and centralized nuclear or fossil power plants using lignite or hard coal. The big four on the one hand sold their electricity into the energy only market by their evolving trading departments as well as into the control reserve markets. On the other hand, they sold electrical energy to the municipal utilities of which they held (the majority) shares and who acted as intermediaries for distribution to final customers respectively distributed it to final customers by themselves. Furthermore, their high market power was underpinned by the fact that these companies were owners of the electricity transmission network or held the majority of shares of the transmission system operators (TSOs) which gave them an information advantage compared to other competitors. Final unbundling of the network operation did not take place until after 2005 (see chapter 2.2.2). The "cash cows" of these vertically-integrated utilities probably were power generation on the one hand and electricity trading on the other hand side (Leprich und Junker 2009, p. 2). According to relatively high flexibility in accounting rules, non-transparencies were prevailing (Leprich und Junker 2009, p. 2). What is more, with their centralized power plants vertically-integrated utilities were responsible for providing ancillary services. The payment for these was ruled by bilateral agreements.

5.2.1.2 Municipal utilities

In Germany, there are around 900 municipal utilities (Schwab 2015, pp. 13–14). These are vertically-integrated companies that are active in different value-added steps of the energy system and mostly in various sectors, i.e. power and gas supply, district heating, organization of public transportation and/or operation of public swimming pools. The field is quite heterogeneous: First of all, the companies are active in a different number of sectors of which power and gas supply are the most common ones. Second, company sizes and service areas vary drastically according to the number of inhabitants and the structure of a region (rather urban or rural). Third, some of the companies have own generation capacities and CHP does have a higher share compared to the large-scale capacities of the "big four". Some others have to purchase all energy from other producers on the power markets. Before unbundling of network operation, the municipal utilities operated the distribution network and were exclusively responsible for delivering electricity, gas and other forms of end energy to final customers in their service area. The main business areas of municipal utilities were power and gas supply to final customers. Only few competition because of implicit market barriers in these areas through high grid charges secured the market position of municipal utilities in an early stage of liberalization. Furthermore, by distribution network operation companies earned a regulated return. Through these "cash cows" a cross-subsidization of less attractive business areas of public utility, like public transportation, was made possible.

5.2.1.3 Transmission system operators and distribution system operators

Due to vertical integration network operators and power producers as well as suppliers where one integrated company before they were forced to fully unbundle in 2005 (see section 2.1.3). The transmission network was operated by the "big four" vertically-integrated utilities. Network regulation provided incentives to maximize power grid investments in order to increase their "guaranteed" returns. These incentives were particularly strong as long as the networks revenues of the integrated suppliers where regulated by a relatively lax cost control regime, followed by a cost-plus regulation (BNetzA 21.1.15, pp. 38–43). Distribution networks were operated by municipal utilities. Principles for network access were formulated by the organizations of electricity companies and network charges were set by the network operators themselves and ex post controlled by the competition authorities (BNetzA 2015, pp. 40-43). So, for the vertically-integrated utilities there was the opportunity to earn a relatively high rate of return for a service with quite low risk which was still prevailing in 2007 (Leprich und Junker 2009, pp. 8–9) and restricted after 2011 when stricter transmission system unbundling rules came into effect. Furthermore, as pointed out in section 2.2.2.2 an incentive regulation was introduced in 2007 in order to provide more incentives for efficient network operations. Within the monopolistic regime which was in place before 2005, network operation and coordination including the procurement of ancillary services was mostly centralized and organized widely by the TSOs. Because of the chance to earn a relatively high return and small changes in the producers structure after unbundling in 2005, there was no or only few need for further network expansion.

5.2.1.4 Decentral power plant operators

The German Renewable Energies Act which entered into force in the year 2000 at first granted renewable plant operators a fixed feed-in tariff. So renewable power producers where paid a certain amount for every kWh of renewable energy they produced and fed into the grid (see chapter 3.2.2). Analogously, CHP plant operators received a fixed payment per kWh of electricity they fed into the grid (for installed capacities, see section 5.2.2.5). It can be assumed that in the past, most CHP plant operators produced power mostly dependent on heat demand instead of electricity demand (Götz et al. 2014, p. 34). The law that promoted CHP formulated no specific flexibility requirements in the first place. In their early stages neither the German Renewable Energies Act nor the CHP law formulated specific requirements for supporting grid stability. To sum up, the incentives for decentral power plant operators in an early stage of liberalization made an operating principle economically reasonable which can be referred to as "produce and forget" or "operate and forget" (Leprich 2012b, slide 18). This means that plant manufacturers were incentivized to construe the power plants independent of grid needs and power plant operators were incentivized to feed in the maximum power that they were able to produce widely independent of power system conditions.[15] By maximizing power output power plant operators were able to earn the highest return on their investment.

5.2.1.5 Industry and other final customers

The amount of own generation and consumption by industrial customers was decreasing during large parts the 20th century (Leprich 2012a, p. 817). Nevertheless, some industries maintained their own generation capacities. Because of combined demand of heat and power for some industry processes, these own generation plants were mostly CHP power plants. The main interest of industry companies in the early stage of liberalization were possibilities for purchasing power at competitive prices. This is why the industry was one of the main advocates of liberalization and made wide use of the new power purchasing possibilities through liberalization of wholesale as well as retail markets. In the early stage of liberalization which relatively moderate shares of renewable energy sources there was no need for adapting to variable energy production by making industry processes more flexible. As a consequence, industry processes remained widely unchanged and there were barely efforts to increase demand flexibility. For other smaller consumers, at first not much had changed compared to the

[15] For variable renewable energy sources the opportunity of controlling power output besides constructional aspects is limited to power curtailments (see Grashof und Weber 2013, p. 17). Leprich et al. (2013b, p. 26) do not see any degree of freedom due to the fluctuating energy production which according to them should be maximized from a system point of view and only be adapted in case of network requirement or overall surpluses (Leprich et al. 2013b, pp. 25–26).

situation with vertically integrated monopolies: Though there were new supply companies, their market position was constrained at first until stricter unbundling rules as well as a regulated network access were introduced. Demand side management and demand flexibility was barely relevant.

5.2.2 Business models in the energy transition phase

Whereas the previous section dealt with an early phase of the liberalization in Germany, the focus for this chapter is shifted towards key actors and their business models in the energy system nowadays (with a time frame starting from approximately 2009). Since the energy transition in Germany can be characterized as an ongoing dynamic process, the final design of target system of that transition is yet unknown and regulatory frameworks are likely to change over time (see section 4.1.2.1) as production, transportation and consumption patterns change. This opens up the field to new actors as well as new business models. New business models may evolve for existing as well as new actors in the power sector or even the wider energy sector because there will be increasing activities in sector coupling. Sector coupling means the usage of power in other sectors to provide the energy services needed and ultimately to replace fossil fuels (BMWi 2016d, pp. 19–20). Again, the prevailing conditions for each of the value-added steps of the power system as well as overarching trends and tendencies are shortly described in the following:

- Investors: In 2015 RES reached a share of 31.6% of gross electricity consumption and 14.9% of gross final energy consumption (BMWi 2016e, p. 4). So current RES shares are much higher than in the early phase of liberalization and still growing. With increasing RES shares, there seems to be a trend towards institutional investors, i.e. actors from outside the power sector itself, investing in RES.
- Production: Besides existing conventional power plants there are a lot of decentralized power generation units which are mostly based on renewable energy sources. At the end of 2015 according to BNetzA (2016a, p. 3) there were 1.6 million renewable power plants – of which more than 1.5 million were solar power plants – that were eligible for the German Renewable Energies Act. So the production structure compared to an early stage of liberalization has changed and today is much more diverse. Among the RES wind energy and photovoltaics are predominant. That means most of the RES electricity production is provided by volatile power sources (see section 2.2.4).
- Network operation: The grid's tasks have changed due to increasing shares of renewable electricity production. Because the units are smaller (low nameplate capacities) they are mostly connected to the lower voltage levels of the electricity grid (Büchner et al. 2014, pp. 6–7). This sometimes leads to bidirectional and

varying power flows: Instead of transporting electricity only unidirectional from higher voltage levels, where large conventional power plants are connected, to lower ones, the power flow reverses at times of high RES-feed from lower voltage levels and low demand. This trend increases with increasing RES shares. (dena 2012, pp. 148–149). According to these changes in the production structure, especially more RES power plants which are mostly decentralized ones, and increasing international energy trading activity, there is the need for grid expansion at the transmission network level (cf. 50Hertz et al. 2017a, 2017d) as well as at the distribution network level (cf. dena 2012; Büchner et al. 2014).

- Trading: As there are higher shares of variable RES electricity trading has become more short notice. This is due to the fact that forecasting quality is much better if the prognosis is made with smaller lead time.[16] Nevertheless, producers as well as consumers are still interested in securing prices in the long run by making use of futures and options markets. In the short run they seek to optimize their production resp. consumption. Power exchanges have reacted to that trend by offering a wider range of products and decreasing lead times. As shown in section 2.2.2.3 the implementation of the European target model aims to support these developments: Market coupling resp. price coupling between neighboring interconnected states of the European wholesale electricity market (EPEXSpot et al. 2016; BNetzA und BKartA 2016, p. 156–157) which was underpinned by the introduction of a flow-based market coupling procedure within the Central Western Europe region in 2015 (Amprion et al. 24.04.2015) are steps into this direction. Interconnector capacities between neighboring European countries are planned to be further increased due to increasing trading and exchange activity (ENTSO-E 2016a, p. 18).
- Supply: The field of power supply to final customers is characterized by a large number of companies and an intense competition. According to BNetzA und BKartA (2016, p. 185–186) in total there were over 1,200 supply companies and on average a final customer was able to choose among 115 suppliers. Some of the supply companies offer white label products which are distributed by other companies. The scope for price discrimination is quite tight, in particular in the segment for business customers were customers are more willing to change suppliers than in the household sector (see section 2.2.3). Due to the high intensity of competition margins in electricity supply are quite low. The prerequisite for enabling competition in the supply (as well as the production) sector was fully unbundling network operation as a natural monopoly from other competition areas along the value-added steps of the power system. This was finally

[16] The first valid prognosis for the variable RES infeed is made one day ahead.

achieved after 2005 when the model of regulated non-discriminatory network access entered into force (see chapter 2.2.2.2).

- Metering: A clear trend towards smart metering can be identified but the planned rollout will take a couple of years from now and to date only final customers with a consumption of more than 6,000 kWh per year are obliged to use a smart meter (§§ 29-32 MsbG). This in turn means that for smaller customers there is no obligation for installing smart metering systems (see section 0).
- Superior Trends: The German energy transition is accompanied by a number of interfering trends which partly go beyond the scope of the energy system itself. These are: decarbonization, decentralization, sector coupling and digitalization. In general, a much greater variety of actors and corresponding business models can be identified compared to the system at an early stage of liberalization.

Table 20 provides an overview on the main actors and their core business activity in the energy transition phase. These are further described in the text below.

Table 20 Actors and their core business activity in the energy system in the energy transition phase

Actor	Value-added step	Core business activity / main interest
RES Investors	Investment	Investment in RES / return on investment
Vertically-integrated utilities	Generation, supply	Conventional power generation, distribution network operation / successful new business model
Municipal utilities	(Generation), supply	Conventional power generation, distribution network operation, other sectors / revenues from DSO; new business model (sector coupling)
RES power plant operators	Generation	Renewable power generation / maximize power production (system compatibility)
CHP power plant operators	Generation	Conventional power generation / maximize power production; containment of business model
TSOs	Transmission network operation	Revenues from transmission, system stabilization / responsibility
DSOs	Distribution network operation	revenues from distribution (and from additional tasks) and from system stabilization / responsibility
Reserve capacity providers	Generation / TSO	Contribution to system stability through existing conventional capacity / surplus revenues
Power exchange operators	Trade	Power Trading / maximum liquidity of power exchange

Actor	Value-added step	Core business activity / main interest
Direct marketers	Trade	Marketing of RES portfolio / maximum portfolio size and revenues
Aggregators / flexibility marketers	Trade	Pooling + marketing of smaller loads / generation units; system services / market access + maximum revenue
Prosumers	Generation / consumption	RES power generation + own consumption / maximizing own consumption to save levies etc.
Supply companies	Supply to final customers	Marketing success; new business models (energy efficiency; hardware; RES integration)
Industry	Consumption; system services; Efficiency	provision of appliances; provision of control reserve / minimizing purchasing costs; additional revenues (through flexibility); Provision of efficiency-related services
Sector couplers	Consumption / other sectors	Usage of electricity in other sectors / regulatory exemptions from levies etc.
Meter operators and smart meter gateway administrators	Metering	Smart metering / using economies of scale to maximize revenue (regulatory price ceilings)

Source: own compilation

5.2.2.1 RES Investors

There still is a large variety of investors that invest in renewable capacity. The spectrum ranges from private persons, depending on the kind of energy source organized in companies or as minority shareholders, to ESCOs and institutional a strategic investors (see section 4.2.2.3). Institutional investors have been investing in RES for a quite a while already. This could be due to the technical and economic progress that renewable energies have already made in the past and due to relatively stable returns due to a guaranteed remuneration. Since policymakers are trying to drive down costs for RES by auctions, there are some concerns that field of RES investors might become smaller due to a competition advantage of larger players.

5.2.2.2 Vertically-integrated utilities

The former “big four” vertically-integrated utilities E.ON, RWE, Vattenfall and EnBW face big challenges due to the energy transition: Their market shares in power generation and supply are decreasing (section 2.2.3) and their renewable energy shares are quite low compared to the German average share (Bontrup und Marquardt 2015, pp. 38–119). These developments can be attributed the “big four’s” strategies vis-à-vis liberalization and energy transition that ranged from neglect to antagonism (Bontrup und Marquardt 2015, pp. 120–205): At the beginning of the liberalization process, the big four saw no need to revise their strategy as regulations for unbundling were not so strict at the beginning and gave them an advantage over competitors. Furthermore, they relied on an extension of the operation permissions for their nuclear power plants which was agreed on by the former German government before the nuclear catastrophe of Fukushima (see section 2.2.4). Finally, the “big four” dramatically underestimated the development of RES in the power sector and missed making investments in that field in an early stage of RES development. Furthermore, they underestimated the effect of RES on wholesale electricity prices, the so-called merit order effect. In addition to that, some of the investment projects in Germany and abroad and acquisitions of foreign companies have proven to be bad investments (FÖS 2015).

As a reaction to declining market shares and revenues, in recent years the “big four” on the one hand seeked to limit financial losses by demanding for compensation for the nuclear phase out and in form of capacity payments for conventional power plants (Bontrup und Marquardt 2015, pp. 206–220). It seems that at least part of this strategy succeeded as recently the German constitutional court judged that E.ON, RWE and Vattenfall are to be paid a financial compensation for taking back the lifetime extension (Spiegel Online 2016). On the other hand, the “big four” tried to rationalize their businesses by cutting down staff and by shutting down unprofitable power plants and seeked to adapt their business models by shifting the focus on international power markets in case of E.ON (Wildhagen und Eisert 2013) as well as grid operation, renewable energies and energy services (Bontrup und Marquardt 2015, pp. 221–256). Recently, both RWE and E.ON as the biggest two of the “big four” have divided the original concern into one area that is responsible for the operation of conventional power plants and one that is active in RES, distribution network operation and energy services for final customers: E.ON is now responsible for the new business areas. The former business segments were outsourced to the new group Uniper which was founded in April 2015 (Schraa 2016) and operates operationally independent of E.ON since January 2016 (E.ON und Uniper 2016). The new business areas of the former RWE group are now organized in the company Innogy which is operationally separated and had its stock market launch on October 7th 2016 (innogy 2017, p. 1; Süddeutsche Zeitung 2017). If the new strategies of the “big four” vertically-integrated utilities will be successful is highly unsure. For 2016, RWE and E.ON again both reported (record) losses (FAZ 2017; Flauger 2017). It seems very likely that the high profits of the past will no longer be achieved even if the new business activities will be successful (Wildhagen und Eisert 2013). This is why Köpke (2017b) draws a negative conclusion as far as the division into smaller units is concerned and declares that the former problems, especially the adherence to conventional and nuclear power plants as well as the missed opportunities of investing in RES in an early phase, are still relevant today. Furthermore, it needs to be noted that part of the high revenues of the past where simply monopoly profits had to be paid by the customer. That is, the same returns cannot be expected today even if the right business model is found. Therefore, Köpke (2017b) points out that in light of the large changes that liberalization and the energy transition bring about and may still bring in the future it is unsure whether or not the "big four" will still exist in the future altogether. Maybe they continue to exist in the form of smaller units. Peter Terium, CEO of RWE, stated in 2013 that the energy transition made clear that a future without the "big four" may be imaginable (Wildhagen und Eisert 2013).

5.2.2.3 Municipal utilities

As stated before, the field of municipal utilities is quite heterogeneous as far as company sizes and activity in the energy system sectors as well as the steps of the value-added chain are concerned (see chapter 5.2.1). That includes that not all municipal utilities have own generation capacities. Through liberalization the former dependencies from the "big four" vertical integrated utilities have decreased as municipal utilities are free to choose a supplier from which they receive the electricity they provide to final customers. In addition to that, this is especially true for their activities in RES. While total investment in generation capacity reduced between 2011 and 2013 they stagnated from 2013 on at just under €5 bn. or ¥648 bn. The RES share grew to 17 % on average while CHP power plants dominate the portfolio and amount to 43 % (VKU 2016). So the activity of municipal utilities in RES compared to the average RES share of Germany is quite low since in 2013 municipal utilities only accounted for 5% of total installed RES capacity (Leprich 2015, p. 53). As noted in section 2.2.3 competition in the field of energy supply is more intense in the segment of professional customers as switching rates of private consumers are still low even though they have been growing. (cf. BNetzA und BKartA 2016, p. 8 and pp. 186–194). The possibilities to earn a return in supply have therefore deteriorated for municipal utilities according to the respective business segment. But even for private customers new online platforms and service providers have specialized on offering final customers very cheap solutions, sometimes including power as well as gas supply or further insurance or telecommunications services and are evolving as new competitors for the incumbent municipal utilities (Sagmeister 2016, S. 1). Whereas revenues in the electricity and gas supply area are decreasing, distribution network operation so far is considered a cash cow for municipal utilities as it offers regulated revenues. The effects of the latest reforms on distribution grid regulation remain to be seen. The permissible return on equity of electricity and gas network has been reduced for the upcoming regulation period (2019-2023) by definition leading to lower returns (Schröder 2017, pp. 11–12). On the other hand, fundamental changes will take effect as of 2019 with the incentive regulation departing from the budget approach for capital cost. That is, under the new system capital cost will be passed through more directly and levied quicker on the network users thereby potentially decreasing incentives for efficiency (Matschoss et al. 2017).

As the classical business models in a way seem to deteriorate, municipal utilities can make use of their special position at the interface between different sectors. Leprich (2015, pp. 54–55) states that municipal utilities could make use of their special position and their customer intimacy as a “decentralized energy system optimizer” in various ways. They could support RES and search for better ways to integrate them into the energy sector. They could also provide decentralized contributions to system stability by introducing more network intelligence for making use of steering infeed as well as load and by exploiting energy efficiency potentials of final customers. In a recently published interview the chairman of the association of municipal utilities said that he sees municipal utilities at a good position for sector coupling because of their activity in different utilities sectors and the operation of gas or heat grids (Nallinger 2017, S. 4). Also Berlo and Wagner (2017) focus on the various advantages of the public utilities. They refer to the utility´s decentrality, local problem-solving competence, capacity for democracy, public value, synergies with other sections (waste, water/waste water, public transport, etc.), energy services, customer proximity and public accessability, and the role as partners for innovative solutions. The authors state (Berlo und Wagner 2017; Wagner und Berlo 2017) that network concession contracts which allow the local distribution grid operator for electricity and gas to make use of public roads, paths and spaces on purpose of the distribution grid operation, open a “window of opportunity” for many municipalities to rebuild and remunicipalise the local energy supply. Between 2010 and 2016 about 8.000 of about 14.000 concessions in the electricity field were estimated to expire in Germany. The number of newly established municipal utilities since 2008 underline an increasing interest of many municipalities in the autonomous foundation of public utilities: Out of 727 total public utilities, 120 utilities (15%) have been newly founded until 2014 (Berlo und Wagner 2017). Most of the municipalities aim to award the concession for the local distribution net operation to the newly founded public utilities. The possibilities to shape the structural change related to the energy transition are manifold. The association of municipal utilities states the following considerations as important for the trend towards remunicipalization (Becker 2011, p. 310) and shows the potential of contributing to the municipals´ finances: The mere grid operation is attractive to the municipalities due to a capital return determined by the network right to 7 to 9 percent. The customers will perceive a public utility appearing at the public as grid operator also as a supplier. Municipalities perceive grid operation as a tactical basis for an improving promotion of autoproduction and electricity supply (including supply). Berlo and Wagner (2017) conclude that own public utilities significantly increase the ability of local politics to implement local climate protection measures and in many places the realization of local and regional value added potentials.

Another future opportunity appears in bundling flexible loads for congestion management that can be marketed to DSOs. Due to recently rising costs of congestion management (BNetzA 2016c, pp. 6–7) which is currently organized at TSO level, there are some considerations of establishing flexibility mechanisms or markets at a regional level which could be organized by DSOs (who remains a regulated party). These approaches are placed at the interface of spot markets and management of network congestions. The bne (2016) proposes that the DSOs should purchase load flexibility from providers that offer their flexibilities on a voluntary basis. A recent study discusses possible mechanisms for the procurement of decentralized flexibility in order to reduce congestion management costs of which most request a high engagement of the DSO (Nabe et al. 2017, pp. 73–128). The exact design of possible decentralized flexibility mechanisms or markets remains unsure as the discussion process has just started (cf. Nabe et al. 2017, p. 29). Therefore possible future changes or extensions of the DSOs tasks are yet unknown.

Again, it is yet unsure how the business areas of municipal utilities will develop in the future. The heterogeneous field of companies doesn't allow for much generalized statements. Municipal utilities sticking to past investment in conventional capacity after liberalization might face a similar fate as the "big four" currently do. On the other hand, with their close contacts to the customer, their interface position between sectors and their high shares of CHP (many fired with gas) they seem to be particularly well-suited for the necessity of the energy transition. This points to the need for a swift implementation of the energy transition strategy. That is, framework conditions matter so that the municipal utilities can play out their strengths.

5.2.2.4 RES power plant operators

As stated in chapter 3.2.2 RES power plant operators received a fixed feed-in tariff at first for a duration of 20 years. The EEG 2009 made first provisions that generators market their produced electricity themselves using a "floating market premium" and that regulation became mandatory with the EEG 2014. For the details of the regulations see the Appendix A. RES power plant operators can make use of an aggregating party, a so-called direct marketer (see section 5.2.2.10), and enter into a bilateral agreement with it to regulate for instance, how costs and revenues are shared between the both. The system of the floating market premium has changed the microeconomic rational of renewable power plant operators respectively direct marketers: At times with negative prices falling below the market premium (plus operating costs) there is a strong incentive to reduce production in order to prevent losses in that specific situation (Grashof und Weber 2013, S. 11). So the floating market influences the marketing strategy of RES power plant operators respectively direct marketers and in addition opens up the potential for new plant installations to exploit sites with a feed-in characteristic that deviates from the arithmetic average of Germany (see section 5.2.2.10).

5.2.2.5 CHP power plant operators

Similar to RES power plant operators, CHP power plant operators receive a premium per kWh for their power infeed which is regulated by the German Act on Combined Heat and Power generation (Kraft-Wärme-Kopplungs-Gesetz, KWKG). In contrast to RES power plant operators, CHP power plant operators receive a fixed premium which is dependent on the installed electric capacity of the plant. CHP power plants smaller than 100 kW receive an additional market price, that corresponds with the quarterly average price for baseload power at the EEX in Leipzig (so called “anlegbarer Preis”, §4 (3) KWKG), if they don’t sell their feed-in directly. In general only feed-in electricity should receive a premium. Under certain conditions they can receive a premium or smaller premium if their power production is used for own consumption as well. To reduce must-run, CHPs under the new KWKG have no claim to the premium and quarterly market price if the day-ahead-prices are zero or negative (§7 (7) KWKG). Often CHP power plants operated by industry companies are used for own consumption since these units help to achieve a high security of supply.[17] In order to make CHP plants more flexible, there have been some adjustments of the German Act on CHP generation in recent years, like granting bonuses for measures that make CHP power plants more flexible, such as the installation of thermal storage systems. Another option to flexibilize CHP power plants is the installation of peak load boilers or power to heat components (Peek und Diels 2016, p. 89–92). As mentioned in section 5.2.1.4, it can be assumed that in the past CHP operation strategies are mainly based on heat demand (Götz et al. 2014, p. 34). This leads to inflexibility in terms of electricity production if there are no technical provisions for flexibilization and a certain heat demand is to be met (Peek und Diels 2016, p. 88–89). Even if technical options are available there are still some economically determined inflexibilities due to opportunity costs which have to be overcome and can be summarized as follows (Peek und Diels 2016, p. 92–93):

- The revenues from providing (additional) power in times of power scarcity need to be high enough to compensate for lost revenues from heat supply.
- In turn, lost revenues of reducing the power output if there is a surplus in power supply have to be lower than opportunity costs of alternative heat generation.

In contrast to RES power plant operators, CHP power plant operators are allowed to keep the so-called “avoided grid charges” which are granted for decentralized power infeed in Germany (§ 18 StromNEV). So, CHP power plant operators included these payments into their profitability calculation. A recent draft proposal which has not yet

[17] Around 30 TWh (DIW und EEFA 2016, p. 16) of a total of 105 TWh of CHP power generation (DIW und EEFA 2016, p. 13) were produced by industrial CHP power plants for own consumption.

been decided on contains the gradually abolishment of “avoided network charges” during the next years (BReg 2017, p. 9).[18] This would worsen the microeconomic situation for CHP power plant operators. Table 21 shows the number of CHP-installations and –capacities that have gone into service 2009-2016 sorted by size. It shows that in terms of capacity the larges additions have generally taken place in the segments of the larger CHP-plants. In terms of numbers of plants it is usually the smaller ones that have been added the most.

Table 21 Number and capacity of new admissions for CHP-plants in Germany according to KWKG, sorted by size

	2009		2010		2011		2012		2013		2014		2015		2016 *)	
Elektric Power	Number	MWel	Number	MWel	Number	MWel	Number	MWel	Number	MWel	Number	MWel	Number	MWel	Number	MWel
<= 2 kW	83	0,12	239	0,27	708	0,7	1.470	1,5	2.032	2,0	1.473	1,5	1.066	1,0	998	0,9
> 2 <= 10 kW	3.222	17,4	1.695	9,0	1.929	10,1	2.088	11,4	2.524	13,4	2.660	14,5	2.092	11,7	1.685	10,0
> 10 <= 20 kW	932	14	649	10	786	13	483	17	1.122	20	1.470	27	937	19	793	11
> 20 <= 50 kW	545	23	475	20	598	25	186	22	684	30	890	38	560	26	690	30
> 50 <= 250 kW	170	25	239	36	253	37	262	37	409	60	600	93	409	63	369	58
> 250 <= 500 kW	52	19	55	19	71	26	89	34	97	37	168	63	101	38	118	44
> 500 kw <= 1 MW	18	12	19	13	36	27	51	39	47	34	110	78	63	46	70	52
> 1 <= 2 MW	40	62	42	67	53	87	52	86	82	135	85	140	57	94	107	177
> 2 <= 10 MW	18	97	14	52	17	94	19	90	47	209	33	137	16	68	13	56
> 10 <= 50 MW	5	132	6	133	3	70	9	174	12	275	14	331	6	110	2	35
> 50 <= 100 MW	0	0	5	384	1	73	1	98	6	391	1	62	0	0	1	67
> 100 MW	1	140	0	0	0	0	1	106	1	191	5	779	3	793	2	828
Sum	5.086	542	3.438	743	4.455	463	4.711	716	7.063	1.397	7.509	1.764	5.310	1.270	4.848	1.369

*) does not contain all numbers since applications could be submitted until 31 Dec 2017

Source: own depiction; data source: BAFA 2017

Taken together, the operation of CHP power plants is highly dependent on the regulatory framework and this framework is currently under revision, as was shown in section 4.1.2.2. The latest downwards revision of CHP targets made large investments in further CHP power plants rather unlikely at the moment.[19] From an energy transition point

[18] The justification for the „avoided grid charges” originally was the assumption that decentralized power plants stabilized the grid by reducing the amount of energy that is taken from the higher voltage levels through their infeed at low voltage levels. With rising shares of (mostly renewable) decentralized infeed, this justification is no longer valid (BReg 2017, p. 8). In contrast, decentralized infeed can be named as one driver for network extension (dena 2012, pp. 148–149).

[19] The original goal of generating 25% of the gross electricity production in CHP power plants by 2020 (status quo 2015: 17.1%; cf. DIW und EEFA 2016, p. 13) which meant around 150 to 160 TWh of electricity was replaced by the goals of generating 110 TWh of electricity in CHP power plants by 2020 and 120 TWh by 2025 (§ 1 subsection 1 KWKG).

of view, however, there is an important backup function for CHP as it is able to provide residual load and replace non-combined capacities. This, however requires a modernization of CHP capacities and a revisions of the regulatory framework that takes into account these new requirements of flexibilization and sector coupling (sections 4.1.2.1.3 and 4.1.2.2).

5.2.2.6 Transmission System operators (TSOs)

Since 2005 transmission grid operation in Germany has to be widely unbundled from electricity production as well as supply of electricity to final customers. In 2011 stricter unbundling rules for TSOs were introduced through an amendment of the German Energy Act (see sections 2.2.2.2 and 2.2.2.3). The TSO are responsible for the secure system operation which includes the provision of system stability within their control area. As a natural monopoly, network operation is comprehensively regulated by the state by making use of an incentive regulation regime (cf. BNetzA 21.1.15; dena 2012, S. 268–275; Matschoss et al. 2017).[20] Since the business area is limited to network operation by law, the only interest of TSOs – within their obligation to provide grid security – is to earn the highest revenues possible from network operation and expansion within the regulatory framework. Because of a control regime by the German regulatory authority (Bundesnetzagentur – BNetzA) and an efficiency benchmark between the four TSOs as well as in the international context the possibilities to earn high returns are restricted by the state in order to adjust revenues to the actual risks of network operation.

5.2.2.7 Distribution System operators (DSO)

As stated in sections 2.2.2.2 and 4.3.2, network operation is regulated through an incentive regulation regime. As a result the business model consists of receiving a regulated return on the networks and related assets. It was also mentioned that the regulatory reform of 2016 (in effect as of 2019) enables a quicker cost pass-through of capital costs. This is particularly welcome for those DSOs with high investment needs (Schröder 2017, pp. 11–12; Matschoss et al. 2017). These occur due to changing network situations for some DSOs due to a higher shares of decentral renewable infeed in some areas.

New business models may occur since most of the power plants are connected to the distribution network and DSOs need to contribute more to network stability. Further, ancillary services can be identified (Schleicher-Tappeser 2013, pp. 28–29). In order to achieve these contributions, cooperation mechanisms between TSOs and DSOs for

[20] Key aspect of an incentive regulation system using an efficiency benchmarking is to prevent the microeconomic rational strategy of a cost based regulation system to maximize network investment in order to receive a maximum revenue (Averch-Johnson effect; Müller et al. 2010, p. 6).

network operation and provision of ancillary services have to be further developed (dena 2014, p. 200). Leprich (2015, S. p. 51) points out that it is furthermore required to intensify cooperation between neighboring DSOs. The bne, an association of German power and gas suppliers, requests to effectively reduce the number of networks who currently optimize their networks separately. This could be implemented in the way of cooperations between DSOs, in order to increase the overall efficiency of distribution network operation (Clausen 2014, pp. 5–7). As the DSOs are located at the interface to the final customers, in theory, they have the opportunity to optimize the system at a decentralized level by (directly or indirectly) controlling or shifting loads as well as power generation within a decentralized load management approach. Because this opportunity is restricted by unbundling obligations, it is not made much use of today. Leprich (2015, pp. 51–52) sees much potential for this approach of a DSO acting as "decentralized system optimizer" balancing demand and supply at a decentralized level respectively as "active DSO" proactively integrating RES (cf. Frey et al. 2008, pp. 86–90). In order to achieve this role model, at least adaptions of the German Energy Act (EnWG) as well as to the incentive regulation ordinance (ARegV) would be required. Nevertheless, there are already some existing regulatory degrees of freedom which enable a decentralized load management to a certain extend: One of them is stated in § 14a EnWG and gives network operators the opportunity to control intermittent loads at the low voltage level. Another one which has to date not been made use of is § 14 subsection 2 EnWG which allows integrating energy efficiency and demand side management measures into distribution network planning processes and should be concreted by an ordinance.

5.2.2.8 Reserve capacity provider

For measures of system stability, several kinds of reserves exist or are planned in the German power sector, respectively. These reserves already exist or will be realized by a procurement of secured capacity through the TSOs. Since to date, there are only limited possibilities for secured capacity besides conventional power plants, the reserves consist mostly of conventional power plants which are excluded from all other (wholesale) power markets including control reserves markets (section 3.1.2). The most important reserves are the network reserve as well as the capacity reserve. Purpose of the network reserve is securing grid stability by providing redispatch capacity. The main aim of the capacity reserve is to match supply and demand in situations of scarcity at wholesale markets (section 4.1.2.1.3).

Network reserve: Since 2013 a network reserve exists in the German power system which is regulated by the ordinance on the network reserve (NetzResV). Goal of this reserve is to provide enough redispatch capacity in the south of Germany or the neighboring states in the south (mainly Austria and Switzerland). This redispatch capacity is needed to cope with congestions in the German transmission grid which are mostly in north-south direction and an oversupply in northern Germany that has to be transported to the south (BNetzA 2016b, pp. 9–10) where according to the prognosis of the TSOs additional secured generation capacity will be needed for network security purposes in a couple of years (50Hertz et al. 2017f).

Capacity reserve: The legal foundation for the capacity reserve was introduced by an amendment of the Energy Act in 2016 (§ 13e EnWG). The capacity reserve will be introduced in winter of 2018/2019. Further details will be regulated by an ordinance yet to be developed (section 4.1.2.1.3).

Although there are different goals for the network as well as the capacity reserve, these two are interacting. Addressees of both reserves are mostly conventional power plant operators. Since power plants are not allowed to participate in any other power markets if they provide reserve, the opportunity costs for providing capacity reserve are quite high. According to that, plant operators will place mostly power plants that are planned for decommissioning because of too low revenues from other markets (see section 4.1.2.1.3) or too high costs for retrofits for the provision of reserves. In § 13d EnWG it is stated that network reserves should be preferentially provided by these power plants. For the power plant operators in turn, this opens up the possibility of further revenues that were not included in their original profitability calculation and hence can be seen as windfall profits. Because of the clear competitive advantage of incumbents it is rather unlikely that new entrants will erect power plants only for providing reserves. This becomes even more likely as there are investigations for new power plant capacity that will be erected and operated by the TSO only for system stability purposes (§ 13k EnWG; 50Hertz et al. 2017f).

5.2.2.9 Power exchange operators

As described above, energy exchanges have developed over time to administer energy transactions between market participants. In Europe, energy exchanges are privately operated companies (e.g. EEX, NordPool). They levy a fee on every transaction and organize the trades in return. That is, they have an interest in a high volume of transactions.

As already pointed out in section 3.1.2.1, the market liquidity of energy exchanges such as the EEX or the EPEX Spot has been increasing over the past years (BNetzA und BKartA 2016, pp. 165 and 173). This trend is expected to proceed into the future because there is an obligation for RES to sell their electricity into wholesale markets. From a power exchange operator's point of view, a maximum market liquidity of power exchanges is at the focus of interest. In order to achieve that the main focus should be on further development of products for supporting short-term optimization of supply and demand portfolios possible.

5.2.2.10 Direct marketers

Direct marketers is a term that describes actors in the power system who pool the generation of RES and offer the electricity generation of their portfolio at wholesale markets. These actors usually enter into bilateral agreements with RES power plant operators in order to market their generation at wholesale markets. Direct market supply of RES power generation is legally binding since the amendment of the German Renewable Energies Act in 2014 (§§ 34, 37 and 38 EEG 2014). Because of the very limited possibilities for long-term prognosis of variable RES generation and due to the construction of the market premium model for RES remuneration, almost all the electricity is sold at the spot markets or – in case of the generation of controllable RES which can be integrated into a virtual power plant (basically a power plant pool) – the markets for control reserve. As mentioned in section 3.1.2, first tests are ongoing to integrate also variable RES into the markets for control reserve (Gust 2017a).

Core business activity of direct marketers is to maximize the revenues of their power plant portfolio. In order to do that, first of all, direct marketers have to establish a portfolio. Second, they have to maximize revenues by optimizing the marketing of the electricity generation using mostly short-term markets such as the day-ahead market as well as intraday markets. Portfolio effects as well as economies of scale play a big role for these market actors: On the one hand, the prognosis of a large portfolio shows smaller deviations from real generation because individual forecast deviations of power plants level out to a certain degree. This in turn reduces balancing costs. On the other hand, there are fix costs (prognosis costs, transaction costs and other), i.e. costs that are – more or less – independent of the size of the portfolio, so a fixed cost degression occurs. According to Köpke (2016, p. 6) there is quite a strong consolidation pressure in the field of direct market supply. In recent time, there have been some acquisitions in the field of direct market supply and some companies without own trading departments exclusively sell white labelling products using the portfolio of direct marketers with own trading departments. The beginning of a market shakeout can be identified which was expected to start in 2016 by many companies (E&M 2016, pp. 34–35).

From the perspective of a company involved in direct market supply, two conducive strategies for anticipating the market pressure and maximizing revenues can be identified:

- One strategy is to maximize the portfolio size in order to benefit from portfolio profits as well as economies of scale. This seems quite hard for new entrants since incumbents have a clear information advantage and already large portfolio sizes.
- Another strategy is market value optimization: This can be realized by including power plants with a generation portfolio that deviates from the German average.

Because of the high simultaneity factors of the variable RE wind and PV (Stappel et al. 2015, p. 23; Hammerschmidt et al. 2012, pp. 3–4; Zipp 2015, p. 150) which do barely have any marginal costs (Leprich et al. 2013a, p. 54), spot market prices are low at times of high variable infeed. This is known as the so-called merit-order effect (Zipp 2015, pp. 1–2; Sensfuß et al. 2008) as shown in section 3.1.2. Another way to describe this effect is the usage of market value factor (Hirth 2013, p. 219). Since wind and PV installations are increasing the market value factor in turn is decreasing (Leprich et al. 2013a, pp. 32–33). If the feed-in characteristic of a certain variable RES power plant deviates from the average of all other plants, by tendency it produces at times with higher spot market prices since all other generation (or demand side) options have higher marginal costs as the variable RE. So if such plants are integrated into the portfolio, this is a way of earning higher revenues (Leprich et al. 2013b, pp. 47–48).

Due to the construction of the market premium model, the microeconomic rational strategy is to reduce the power infeed if the absolute value of negative prices is high enough. This is due to the relationship between contribution margin and spot market price. For details see Appendix B.

5.2.2.11 Aggregators / flexibility marketers

Aggregators in the power system are responsible for bundling resp. pooling smaller generation or consumption units in order to market their generation or consumption at different markets in the power system. Basically, direct marketers which were described above fulfill an aggregator function and could be included here as well. Deviating from the general definition above, the term aggregators in the German power system is often used for new players that are especially active in the markets for ancillary services and that usually bundle demand side management (DSM) options (VKU 2015; dena 2013, pp. 1 and 6). Since aggregators form quite a new group of actors and the field is quite heterogeneous as there are many forms of small load as well as generation units, the actor role is not yet clearly defined. In Karg et al. (2014, p. 211) a broad definition of aggregators is contained, including loads as well as generation units. One common characteristic is that their main task can be identified as optimally marketing a certain portfolio of units (Karg et al. 2014, p. 215). Like in direct market supply, portfolio effects are crucial for these actors. Two groups of aggregators can be distinguished whereby the two groups coincide at some point: aggregators for flexible loads as well as aggregators for system services.

Aggregators for flexible loads: Aggregators for flexible loads pool demand side units in order to be able to market their aggregated load reaction which is steered by certain price signals. Since other special markets for (regional) flexibility do not exist to date, the demand flexibility is offered mostly at secondary control reserve or tertiary/minutes reserve markets. In the past regulations have been unclear on how to handle deviations of the balancing responsible party (in this case: the supply company of a final customer) if the aggregator is a third party and therefore not equivalent to the balancing responsible party itself. This has been an obstacle for third parties evolving in this market (see section 3.1.2.1). This has been resolved recently by a guideline from parties of the energy branch that defines how to handle these deviations (50Hertz et al. 2016). Besides the control reserve markets, the markets for interruptible loads which are regulated by the ordinance for interruptible loads constitutes another option for pooling loads is for interruptible loads.

It is imaginable that other regional markets for flexibility may evolve in the future since there is an ongoing discussion for possible flexibility markets which are aligned at congestion management at DSO level (Nabe et al. 2017; bne 2016). Markets for flexibility shall be technology neutral (BMWi 2015b, pp. 41–42). Therefore, flexibility options should compete on all levels, i.e. on the generation side (incl. storage facilities) as well as on the demand side. The latter is important to open up the field for aggregators optimizing, in turn, supply and demand side options in their portfolio.

Aggregators for system services: Quite often, the term aggregator is used in conjunction with the provision of system services (Schleicher-Tappeser 2013, p. 12) such as control power and reactive power provision for instance. Among the system services, only control reserve is procured following a market based approach (see section 3.1.2). The current design of the three control reserves markets demands for relatively high minimum product sizes of 1 MW resp. 5 MW. Because these minimum product sizes cannot be achieved by small generation resp. production units, pooling of technical units is allowed. The aggregator in this case is a virtual power plant operator who tries to manage and optimally market the pool. He has to decide which units to activate if control energy is demanded by the TSO on a techno-economically basis. In order to simplify the activity of aggregators and to increase the potential of flexibilities participating in the markets for control reserve, an adaption of the market rules for control reserves would be helpful for these actors, reducing lead times as well as product duration.

5.2.2.12 Prosumers

Prosumers form a new group of actors that has emerged during the energy transition (distinct from industrial autoproduction that has existed before, see section 5.2.2.14). The terminus is used to describe a party that either produces or consumes energy, depending on the situation. The energy produced is used for own consumption with excess energy being fed into the grid. The latter is especially the case for surpluses of variable RES generation that cannot be consumed at that time. Gährs et al. (2016, p. 3) define own consumption as a distinctive attribute of prosumer households whereas households that feed all the electricity into the grid are not included in the prosumer definition. A typical example for a prosumer is a household owning a rooftop PV that is producing energy for own consumption and feeds surpluses into the grid. Early stakeholders also had the idea of energy autonomy (section 4.2.2.3). In the future, prosumerism may play an increasing role on the level of quarters (sections 7.2.2.1 and 7.2.6). In the ensuing text, the focus is put on households with rooftop PV. As the PV power plant operates variably, the household customer takes electricity from the grid in situations when the PV's output is insufficient. In a growing number of cases, the rooftop PV is combined with a battery storage system that enables to increase the share of own consumption. This is due to incentive schemes for battery storage that are set up by the government with the latest program in effect since 2017 (KfW 2016).

Since costs for PV power plants have decreased drastically in the last years and for rooftop PV so-called "grid parity" for new installations was reached at the beginning of 2012 (Wirth 2017, p. 11), a new business case for own consumption evolved: Since then electricity produced from the rooftop PV plant has become cheaper than electricity purchased from the grid (Jahn und Deutsch 2017, p. 48) because household electricity prices contain a number of charges, levies and taxes (network charges, the Renewable Energies Act levy, the electricity tax etc.) which are levied per kWh (see chapter 6.3 for more details). So this particular business case builds on achieving savings that in part have to be compensated for by other network users (cf. BNetzA 2015b, S. 52). There is an ongoing debate on whether or how to integrate own consumers in the payments for financing the network infrastructure, on the relevance of the problem etc. (Jahn und Deutsch 2017, S. pp. 52–53). In reaction to this debate, a partial integration of own consumers in the payment of the Renewable Energies Act levy was decided in 2014 (§ 61 subsection 1 EEG 2014). In 2016 the integration of own consumption in electricity tax payments was discussed but has been withdrawn before becoming legally binding (Hahn 2017). There have already been concrete regulations for including own consumption in the payment of levies and fees. Furthermore, there are discussions on expanding the payments of the own consumers which is why it is crucial for prosumers to keep these developments in mind. A profound sensitivity analysis is needed that pays attention to the impact of falling wholesale electricity prices as well as potential obligations for further payments which could significantly worsen the microeconomic calculus. Again, a high sensitivity towards regulatory adjustments can be identified which makes it hard to predict how own consumption and prosumer models will develop in the future.

5.2.2.13 Supply companies

Supply companies buy electricity from producers and sell it to final consumers. Competition among supply companies has been rising. As mentioned above, there is a large number of companies, according to BNetzA und BKartA (2016, p. 185–186) in total over 1,200. White labeling (selling the product under a different brand name or no brand name at all) is quite common since some of the supply companies do not have own trading departments. Due to the high competition intensity, margins in the supply segment are quite low compared with other value-added steps of the power system. This seems especially true for the field of large customers: EnBW as one big player has announced to terminate its wholesale business delivering large customers such as industry companies and intermediaries in 2016 according to low margins (EnBW 14.06.2016). Other companies might follow suit.

Due to the low margins, product differentiation and marketing plays quite a big role in the supply sector: This can be achieved by creating a green image of the company for example. A lot of companies offer “green electricity” or “ecological power” products, i.e. products which have a high share of RES power in the portfolio (Reichmuth 2014; BNetzA und BKartA 2016, p. 231). This in turn is achieved by buying guarantees of origin for RES. So far, no guarantees of origin have been issued for renewable electricity generation (this has only been introduced with the latest revision of the feed-in tariff – see section 7.2.3). Therefore, guarantees of origin are so far bought at an Europe-wide market place (Leprich et al. 2015, pp. 208–210). Other companies combine their power products with other hardware offers (Müller 2016; Sagmeister 2016, p. 1) or offer new tariff structures such as flatrates (Leßner 2016; Hoeren 2016).

As Leprich (2015, p. 52–53) states, supply companies in theory have the potential to integrate RES sources and compete for balancing their fluctuations by procuring demand as well as supply side flexibility options at a decentralized level (cf. Hauser et al. 2014). As a prerequisite for this approach, the system for integrating RES sources into the power markets would needed to be changed. This is currently not being discussed in the political landscape in Germany anymore. Independently on whether or not such a system change might occur, supply companies have the potential to procure resp. incentivize energy efficiency measures as they are positioned at the interface to the final customer (Leprich 2015, p. 53). Again, regulatory adaptations for this are needed: At the moment, supply companies still face counter incentives to supporting energy efficiency measures as reducing their kWh sold will automatically reduce their revenue. This could change if the new energy efficiency directive which is being developed at the EU level will contain obligations for supply companies to achieve certain energy efficiency targets. From the considerations above, it becomes clear that supply companies need to develop very differentiated products (whatever these may look like) in order to be successful in a highly competitive market. Whether their market role will be expanded significantly or not is mostly dependent on the development of the regulatory framework.

Another supply channel is a pool of renewable or CHP- producers and consumers who market their power through a community manager. The goal is to provide the community members as final customers with the power from the community to the degree possible. The remaining power is bought from the market. Some communities oblige themselves to buy their own hardware like PV- and/or storage systems. In most communities the members have to pay a member fee as part of the electricity price. (Müller 2016)

5.2.2.14 Industry

As more than 40% of total net electricity demand in Germany is attributed to the industry sector (cf. Ziesing et al. 2016), this sector is of particular interest for the German energy transition. There are some new business models arising from the energy transition and others have existed before but now gain more importance. First of all, it needs be distinguished between industries that use energy as an input factor and industries where the provision of energy efficiency constitutes the business model itself. For the first group energy is a commodity and there are various strategies to reduce energy costs in order to gain a competitive advantage. This may be increased energy efficiency or adapting energy demand profiles from the grid to reduce levies. The second group, in contrast, provides energy efficiency-related products and services to the first group and to other sectors (e.g. housing). That is, various business models may be created around energy efficiency-related products and services (optimization of systems in buildings and industry, financing of contracting etc.). The first group, however, may also do part of these services themselves (inhouse).

In terms of reducing energy costs (the first group) one strategy is own consumption. So far, this is mostly based on CHP and shall avoid high network charges that could occur by increasing the individual annually peak demand. Another reason is high requirements for security of supply. (Peek und Diels 2016, p. 134–135).[21] Still, the main interest of the industry remains cheap power purchasing which they can achieve by optimization purchase strategies using a wide range of power exchange products or through power suppliers dependent on whether they are able to directly purchase at power exchanges or not.

Other measure to reduce energy costs include process flexibilization. With rising flexibility needs, growing attention has been paid to possibilities for increasing electricity demand flexibility in industry processes. This is due to two aspects: On the one hand, through flexibilization of industrial processes further income streams can be made available such as revenues from the control reserve markets or from the use of the ordinance for interruptible loads (AbLaV). Therefore, this contributes to overall system stability (Klobasa et al. 2013, p. 22). On the other hand, flexible industry loads that are procured via spot markets can help to reduce the need for additional capacities on the

[21] According to the regulatory system design, some other regulatory determined price components are not or only in parts to be paid by consumers using own consumption.

supply side that would be needed only in very few situations and therefore account for relatively high specific costs (Connect Energy Economics 2015, pp. 17–18). Flexible loads are especially useful in a system with high shares of variable RES since they can help to reduce the overall system costs (Connect Energy Economics 2015, pp. 29–30). Therefore, flexibility on the demand side is substitutional to supply side flexibility and can help to anticipate the fluctuations of variable RES (Nabe 2016, pp. 21–23; VDE 2012, pp. 18–19). From a microeconomic point of view, the industry company flexibilizing its demand could benefit from lower average power prices when its demand is shifted from times with high prices and low RES infeed to time with lower prices and high RES infeed (cf. Peek und Diels 2016, pp. 61–62). The current system and market design, however, involves a number of obstacles against load flexibilization. Among others these include (Jansen et al. 2015, pp. 21–24; Krzikalla et al. 2013, pp. 31 and 35; Connect Energy Economics 2015, pp. 35–43; Nabe 2016, pp. 34–39):

- Rather high costs for investments in flexible processes, including rather high costs of carry (high opportunity costs),
- Too low prices as well as too little spreads at spot markets,
- A restrictive market design of markets for control power (long lead times, long product duration) as well as market saturation for this markets,
- Network charges, that are highly sensitive to the individual annual demand peak load,
- Fixed duties, levies or other charges,
- Paucity of information.

Additionally, restrictions from the process side and a high need for planning security can be named as one big obstacle for flexibilization of industry processes. Again, for load flexibilization as well as for energy efficiency measures, a high sensitivity on behalf of regulatory circumstances can be identified. How potential business models for energy efficiency as well as flexibilization will develop is dependent on a number of external factors, including overall secured capacity availability (supply, demand, storage, electricity networks) as well as the development of regulatory circumstances.

On specialized industries (the second group) recent policies on energy efficiency aim at establishing markets for energy efficiency as an enabler (section 7.2.2.2). Energy service companies (ESCO) is one example of specialized companies built on the business model of contracting. That is, a third parties (ESCO) provides heating and cooling services to the owner of the house by providing machines, knowledge and finance and is paid for the service (BMWi 2015c, section 6.4). The ESCO may be a “new” company or an established energy provider. Another aspect is the provision of energy efficient appliances for households and industry (section 7.2.2.2). Here, these are “normal” appliance manufacturers. However, with energy efficiency regulations for appliances energy efficiency becomes more important in product development.

Some companies have shifted their focus on the possibilities of digitalization that the energy sector brings along. This is especially true for the former “big four” vertically-integrated utilities who try to intensify their business activities in this segment (Bontrup und Marquardt 2015, pp. 264–266). Since a lot of solutions include automation as well as hardware solutions, this business area is open to companies from outside the power sector.

5.2.2.15 Sector couplers

From an energy transition point of view there are two tasks for sector coupling: in the short term sector coupling may contribute to the reduction of network congestion costs as it may provide additional load for electricity in times of high feed in from VRE. In the longer term sector coupling will gradually introduce RE and thereby replace fossil fuels in other sectors than electricity (heat, transport) in order to decarbonize those sectors.

There is not yet a clear description for ‘sector couplers’ as new actor group resp. new responsibilities in the power system. It is yet unclear, which actors of the power system will be at the front of sector coupling since the regulatory framework builds up obstacles for sector coupling. In particular, network charges, levies and taxes have a restrictive impact on sector coupling (BMWi 2016d, p. 20). This is because for all monovalent power to X appliances, network charges, levies and taxes are to be paid for the electricity taken from the grid as it is defined as ‘final consumption’ (Sitte 2015, slide 23) as pointed out in section 3.1.2. Probably, existent actors of the power system will take the part of a ‘sector coupler’ and not necessarily new actors are needed for this task. Especially municipal utilities which are already active in more than one sector (Nallinger 2017, p. 4; see paragraph above) as well as industry companies who have to cover their own demand have a good starting basis for being active in sector coupling. At final customer level, households in a way might as well act as sector couplers by using heat pumps or electric vehicles if there are incentives for this. Municipal utilities resp. their subsidiaries as DSOs hereby could form the superordinate part by coupling electricity and gas or heat networks for integrating power to gas or power to heat processes at a superordinate level. Whereas for industries as well as households recovering their own demand is at the center. For industry processes besides power to heat appliances, power to liquid and power to fuel or chemicals are options for decarbonizing this sector. At a household level, power to heat and electric mobility will probably be at the center of interest.

As stated above, from a microeconomic point of view, power to X appliances are not yet profitable because the sum of the spot market price and network charges, levies and taxes is usually higher than the costs of an alternative provision of the energy service X (e.g. heat, syngas, synfuels). From a macroeconomic point of view, this seems rational because in the system today there have not yet been situations where the overall renewable infeed was greater than the current demand. RES reached at maximum 86.3% of overall demand in 2016 (Graichen et al. 2017, p. 4) so there was no need to find usage possibilities for excess production from RES on a nationwide level. From a macroeconomic perspective, large-scale sector coupling for the purposes of decarbonization will probably only be needed from around 2030 on as current studies for the development of the power system show (cf. Repenning et al. 2015; Schlesinger et al. 2014; Haller et al. 2016). However, on a regional level, RES-shares have been well above 100% and it is expected to stay like that as VRE-expansion is expected to be faster than the expansion of the grid. That is, sector coupling will play a role in the further decentralization of the energy system (Agora Energiewende 2017a).

In order to make sector coupling profitable on a microeconomic level, there have to be changes in the regulatory design, introducing adaptions from network charges, levies and taxes as demanded by some parties (Antoni et al. 2016, p. 48; bne 08.03.2017). Whether or not, these regulatory changes will be introduced is a political decision.

5.2.2.16 Meter operators and smart meter gateway administrators

The smart meter gateway administrator is a new role in the German power system. This actor is responsible for the administration of the smart meter gateway which is the central communication unit of a smart metering system. Especially, the smart meter gateway administrator is responsible for the configuration of the gateway as well as the secure operation and encryption of data. The German Federal Office for Information Security (BSI) therefore has defined minimum standards for data security as well as data privacy (BSI 2015, pp. 13–19). Since the meter operation law has introduced a legally binding smart meter rollout for consumers with more than 6,000 kWh of annual consumption as well as for generation units with more than 7 kW nameplate capacity (§ 29 subsection 1 MsbG) – see section 7.2.4 –, the role of the smart meter administrator will become more important. The most important tasks of the gateway administrator are to secure communication and to provide data security and privacy as well as protecting the smart metering system from assaults. According to market participants, the revenue perspectives are restricted by tight regulatory standards and high requirements (cf. § 25 MsbG). Hence, they are largely influenced by economies of scale (Füller und Sobótka 2016). The meter operation law defines that the meter operation includes the smart meter gateway administration (§ 3 subsection 1 MsbG). Therefore, the price ceilings that are regulatory determined in § 31 MsbG form an upper bound for the revenues from meter operation as well as gateway administration. Due to the high requirements there are some tendencies that network operators who formerly acted independently form cooperations for smart meter gateway administration (Gust 2017b; GWAdria).

6 Distribution of costs and risks

The following section of 'general distributional mechanisms' deals with the distribution of costs and risks of efficient and clean dispatch and of financing mechanisms for financing firm as well as variable and (mostly clean) capacities. It also deals with general changes of risks due to liberalization. The second section shifts the focus towards 'specific distributional mechanisms'. These include the allocation of network costs and other levies which are network-related as well as taxes that are directly charged on electricity prices.

6.1 General distributional mechanisms

This section on 'general distributional mechanisms' includes general changes of risks due to liberalization, the distribution of costs and risks of efficient and clean dispatch and of financing mechanisms for financing firm as well as variable and (mostly clean) capacities.

6.1.1 Japan

6.1.1.1 Efficient dispatch: changing risks due to liberalization

There are many possible risks and benefits associated with the electricity market reform in comparison with the traditional electric supply system. In the following, there will be taken up a few cases of risks and costs involving a change from the traditional system to market-based system.

Under the traditional cost-of-service regulation in general, recovery of prudent costs and fair rate of return were guaranteed. Electricity rates corresponded to these costs of service or required revenue if they were approved as prudent costs by regulators. This rate-making system was universally adopted in major countries during post-war period up until competition replaced regulation. In return, electric utilities were mandated to supply electricity to customers in defined supply areas. Japan is no exception before liberalization began in 1990's. Electricity rates based on cost-of-service implies that various risks facing electric utilities were borne ultimately by final consumers unless regulators intervened.

Taking an example of the generating sector, investors in IPPs are likely to assume more risks than investors in utilities under traditional cost-of-service regulation. Three major types of risk are faced in supplying electricity: construction, operating, and demand forecasting risk. Construction risk refers to the risk that a plant's actual construction cost and/or its construction time will exceed original expectations, or that the plant will be deferred or cancelled and never completed.

Operating risk refers to the risk that the plant's running costs will be higher than expected or that the plant will operate less reliably than expected. Demand forecasting risk refers to the possibility that the demand for power from the plant will be different than expected.

The above-mentioned risks were borne by ratepayers as a class. Electric utilities expected to recover all costs as long as the costs were prudent. In contrast, non-utilities are likely to bear many risks borne by ratepayers and the purchasing utility's investors. They are likely to bear most of the risks associated with construction and much of the risks of operation. Utilities are not likely to agree to make payments to IPPs unless IPP are able to provide the power they have contractually obligated themselves to provide. If the plant closes temporarily or permanently after it becomes operational, or if the plant is never completed, IPPs will receive nothing. Thus, unlike traditional regulated utilities, IPPs investors are likely to bear all construction risk and a great deal of operating risk since purchases from IPPs would be voluntary. Unbundled generating companies of incumbents will be likely exposed to these risks. The shift of risk from ratepayers and utility investors to investors of IPP is important for economic efficiency because decisions are then made by the same individuals who bear the risk of their decisions.

Next example is financial risks associated with competition. Under the old regime of regional monopoly and vertically integrated system and cost-of-service regulation, electric utilities were stable institutionally. For financing, it was possible for incumbents in Japan to issue the general mortgage bond which uses blanket mortgage on all of its collateral to secure the debt. It should be noted that the balance of issued electric power bond accounts for approximately 20% of the bond market in Japan. Incumbents were also treated preferentially by the banks because the default risk was considered to be quite small. In 2015, the share of equity in capitalization was 15.2% for incumbents while the average share for all industries was 39.9%. With the advent of competition, the financial condition surrounding incumbents is changing, so that the cost of capital will be highly likely to increase which is led to increase in the cost.

As stated in the above, consumers do not necessarily bear all costs involving electricity supply in competitive markets for power unlike in the traditional regulatory system. However, consumers have continued to bear almost all costs as the competitive markets have not developed fully in both wholesale and retail markets though rates are suppressed by stringent regulator's prudence review.

6.1.1.2 Clean dispatch: Distribution of FIT costs

Since FIT was introduced in 2012, spread of PV was very quick due to lucrative FIT prices for developers. Remarkable amount of PV was installed. Yet, most of developers were not local companies but major large-scale companies which have headquarters in metropolitan areas. Therefore, local economies were not said to be a beneficiary of investment in PV.

Table 22 FIT Cost (2012 - 2030)

	2012	2013	2014	2015	2016	2017	2030
FIT Cost (billion €)	2,4	3,7	6,4	13,6	19,1	22,4	30.6-33.1
Surcharge(€/kWh)	0,002	0,003	0,005	0,012	0,019	0,022	-
Monthly Surcharge (€/month)	0,644	0,812	1,602	3,527	5,623	6,558	-

Note: surcharge is derived by the following formula: Surcharge = (purchase cost-avoided cost + other costs)/(electricity supply); Assumption: standard household consumes 300kWh/month.

Source: ANRE 2017e

Table 23 Exemption Rate for manufacturing and Non-Manufacturing Industry

	Conditions met	Conditions unmet
Manufacturing	80%	40%
Non-manufacturing	40%	20%

Source: ANRE 2017e; Note: see Table 22

Table 22 shows FIT costs and surcharges over the years and estimate for FIT costs in 2030. As it indicates, surcharges as well as FIT costs are increasing significantly. For the industrial customers who are electricity-intensive industry, FIT costs are partially exempted if the following conditions are met:

- Entity in the manufacturing sector which exceeds 8 times of the average unit intensity (electricity consumption per €8.3 of revenue). For non-manufacturing sector, entity which exceeds 14 times of the average unit intensity is eligible. Entities in both manufacturing and non-manufacturing sectors must exceed 5.6kWh/€8.3.
- Electricity consumption of business that the entity applied for must exceed one million kWh.
- Electricity consumption of business in application must account for more than half in electricity consumption by the entity.
- Entity engaging in improving the unit intensity.

Exemption rates for satisfying the conditions are shown in the Table 23.

6.1.2 Germany

6.1.2.1 Energy system costs vs. distribution of actual costs

When costs of the energy system are concerned, at first a distinction between theoretical overall system costs of a certain energy system constellation and the actual costs incurred of the current system that need to be distributed has to be made. The theoretical overall system costs are non-trivial to quantify and the calculation requires certain assumptions. They can be used to compare different pathways of the energy system such as a fossil-nuclear pathway vs. an energy transition pathway by calculating so-called 'system analytical differential costs'. It shows that in 2050 even without the internalization of external costs a renewables-based system will be cheaper than a fossil-based system (Nitsch et al. 2012, pp. 28–30, 2012; Agora Energiewende 2017b). These theoretical costs are not looked at in this paper. Instead, the actual costs incurred are at the focus of interest here. It is analyzed, how these costs are distributed, i.e. which general mechanisms are used resp. which exemptions or redistribution mechanisms exist. Furthermore, a look is taken at how the costs interfere with the corresponding risks.

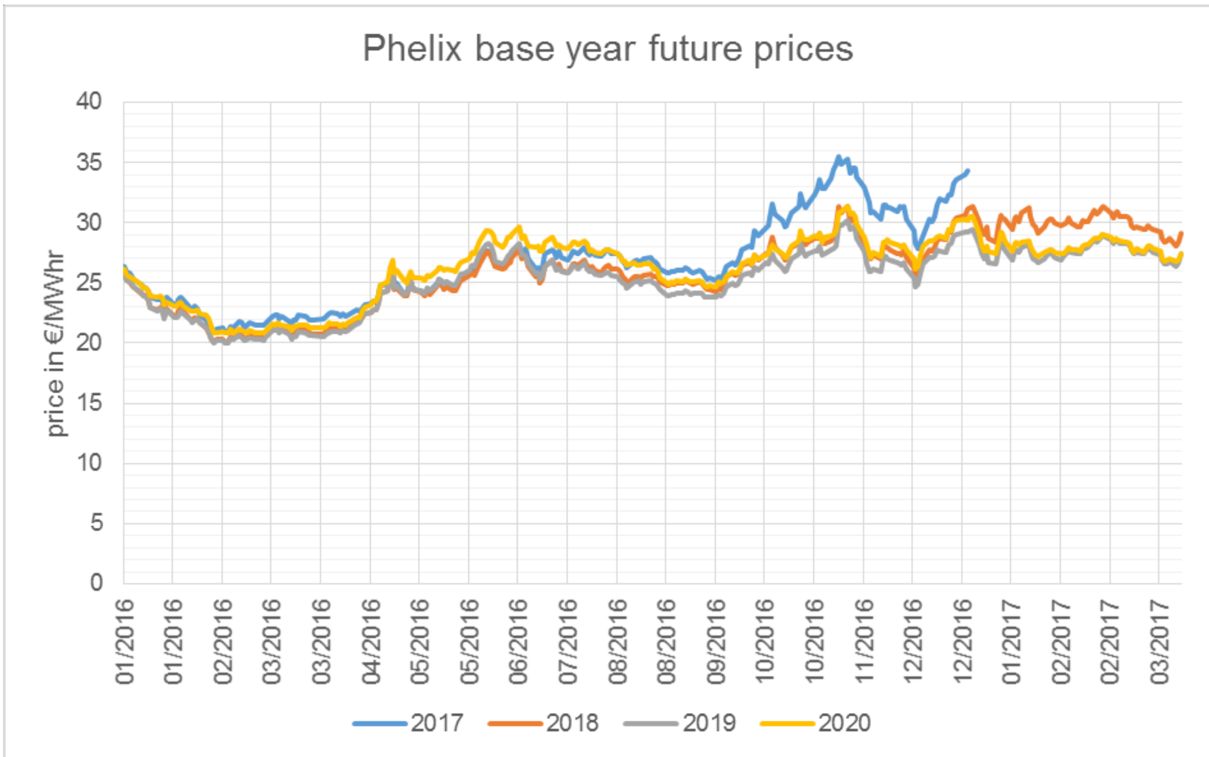
In Germany, energy intensive industries have been exempt from most energy and CO_2-related taxes, levies and charges on the grounds of international competitiveness. The chapter shows that the regulations vary strongly on (i) who qualifies for the exemptions and (ii) what degree of exemption is necessary/appropriate. Therefore, it is difficult for other consumer groups to understand these regulations. Furthermore, with most regulations it is not comprehensible how international competitiveness is measured. Instead, energy intensity appears as the only measure. The rising financial obligations for these consumer groups who do not benefit from the exemptions together with an overall lack of transparency of the regulations may negatively impact the acceptance and, in the end, may have a negative impact on the support for the energy transition as a whole. Both calls for an adjustment of the regulations on both levels: the design of the regulations of the exemptions as well as the design of the overall financing scheme.

For a consideration of 'general distributional mechanisms', the focus lies on the questions of how costs and risks of efficient as well as clean dispatch and of financing mechanisms for financing firm as well as variable and mostly clean capacities are distributed among the actors of the power system.

6.1.2.2 Efficient dispatch: financing conventional generation and ancillary services

The costs of power generation ultimately is passed onto final consumers on a kWh basis since supply companies purchase the electricity at the energy only markets and act as intermediaries. Basically, generators face a price risk, i.e. the risk of insufficient revenues at energy only markets. By tendency, this risk is increased due to declining spot market prices caused by a number of factors (Zipp 2015; Hirth 2013) (see section 4.1.2.1.2). The consumers as a hole in contrast, generally face a risk of high prices at energy only markets. This risk in turn is reduced by a declining price trend at the energy only market which can be seen at least in the short term in Figure 50.[22]

Figure 50 Development of baseload future prices for Germany



Source: IZES / own depiction; data source: EEX 2017b

The costs for the provision of control reserve are passed onto final consumers as well (BNetzA und BKartA 2016, p. 124). This is done by including these costs in the revenues of TSOs and hence adding them to transmission network charges (kWh as well as kW charges dependent on the group of final customers). Chapter 6.2.2 deals with the cost redistribution through network charges. Since it may be argued that control reserve is a safety mechanism to retain overall system stability, adding the cost to the network charges can be seen as reasonable approach. This safety mechanism is needed regardless of which balancing responsible party (BRP) is responsible for a

[22] The Phelix base year future prices for 2018 to 2020 in 2016 at maximum around €30 or ¥3,609 per MWh. As these values represent an indicator for the expected spot market price development, no rising spot market prices are expected for the near future (cf. Graichen et al. 2017, S. p. 29).

certain system deviation. Due to this reasoning, costs of control reserve represent the monetarization of a potential risk of system instability. In contrast, some parties argue that the costs of the provision of control reserve should be compensated for by the BRP as well in order to increase the incentive for BRPs to level out their balancing groups (Peek und Diels 2016, pp. 181–182).

As described above (see chapter 3.1.2), the costs for balancing energy are passed onto the BRPs whose individual deviations lead to an increase of the overall system deviation (Peek und Diels 2016, pp. 167–168). Consequently, the BRP has to carry the risk of its individual deviation from the scheduled generation resp. consumption which is source-specific.

In section 4.1.2.1.3 it has been explained that in Germany there are no capacity markets, i.e. no mechanism for financing *all* firm capacity. Nevertheless, a heterogenoues mix of instruments exist for financing particular firm capacities:

- One group of instruments is financed through an add-on on the transmission network charges of final consumers. This group comprises the network reserve according to § 13d EnWG and the NetzResV, the capacity reserve which is to be established in 2018/2019 according to § 13e EnWG, possible future network stability power plants according to § 13k EnWG, the CHP levy according to the KWKG as well as the levy for interruptible loads according to the AbLaV. While the network and the capacity reserve address almost exclusively existing capacities, the network stability power plants per definition are new capacities. The CHP and the AbLaV address new as well as existent capacity. There is a restriction on the overall capacity for the latter two mechanisms, though.
- Another instrument in turn is financed through the Renewable Energies levy. For biomass power plants an additional payment per kWh is granted if the plant is operated in a flexible way (§ 50a EEG 2017). For existing power plants a flexibility premium is granted if the plant is operated in a flexible way which includes a higher payment (§ 50b EEG 2017; Jansen et al. 2015, p. 25).

6.1.2.3 Firm clean dispatch; financing the EU ETS and CHP

The costs of the EUAs which are to be purchased under the EU ETS, are ultimately passed to final consumers. There are some exemptions made for industry companies for which the costs occurring by including power prices in the ETS are assumed as being too high (BMWi 2013). Hence, these revenues cannot be used for financing any additional climate protection projects. In a way, the ETS can be seen as a marked-based mechanism for (partly) monetarization of environmental risks of GHG emissions.

The Act on CHP generation (KWKG) determines a CHP levy which is passed to final consumers and added onto final consumer transmission network charges (§ 26 subsection 1 KWKG). Again, like discussed above for the Renewable Energies Act, the risks are shared between the final consumers on the one hand and the CHP power plant operator on the other hand who faces mainly a price and revenue risk but also a quantity risk since there is no dispatching priority for CHP so that the CHP-capacities have to compete with other forms of electricity production. For CHP power plant operators the risk of regulatory adaptions that might lead to retroactive consequences worsening their original profitability calculation is especially prominent because a phase out of the avoided network charges is currently being intensively discussed (see chapter 5.2.2). In contrast to the Renewable Energies Act, the costs are also shared between power plant operators and final consumers since the Act on CHP generation doesn't compensate for the full costs (the LCOE) of CHP power plants which have to recover their costs at wholesale markets or through own consumption. A differentiation in turn is made between the levies imposed on final consumers: small consumers pay a higher amount per kWh than medium size consumers who in turn pay a higher amount than very large consumers.

6.1.2.4 Variable clean capacity: financing the EEG

The Renewable Energies Act distributes the costs for financing RES to final customers in form of a levy which is charged per kWh of final consumption. Since the amendment of the Renewable Energies Act in 2014, own consumption is levied to a certain percentage (§ 61 subsection 1 EEG 2014). The Renewable Energies levy is calculated by the TSOs on an annual basis. The calculation is published on their transparency platform (cf. e.g. the latest calculation 50Hertz et al.). There is a significant redistribution alongside different consumer groups since there are special rules for energy-intense companies which are widely excluded from payments of the Renewable Energies levy (§§ 63-69a EEG 2017). Due to an intervention by the European Commission, (DG Competition), sectors have been defined who are electricity intensive and exposed to international competition and therefore only need to pay a limited levy resulting from the promotion of renewable energies. (European Commission 28.06.2014, Chap. 3.7.2.) In recent years, the exemptions and levy reductions have been extended significantly which has led to an intense discussion on whether all companies that benefit from the extra rules face international competition which was the original justification for the extra treatment (cf. e.g. Horst und Hauser 2012, pp. 15–16). Due to the exemptions mentioned, only 75% of total final consumption is levied in 2017 (50Hertz et al.; own calculation). So in a way, the construction of the Renewable Energies levy leads to a redistribution of costs away from large consumers towards households and other smaller customers.

As far as risk allocation is concerned, the floating market premium which is granted based on the Renewable Energies Act partly distributes risks away from the RES power plant operator resp. the direct marketer: The plant operator resp. the direct marketer faces part of the price risk as well as the quantity risk as a whole. The price risk hereby describes the risk/chance of earning lower/higher prices at spot markets. The quantity risk/chance refers to the energy produced by the respective power plant which could be lower/higher than originally projected and which can deviate between the years causing liquidity deficits/surpluses. In addition to that, the direct marketer has to carry balancing energy cost and faces the risk of deviations from the electricity produced. The society, i.e. the final consumers, faces the rest of the price risk which is reproduced by their payments of the Renewable Energies levy.

6.1.2.5 Preliminary conclusion

As a preliminary conclusion it can be said that the costs of conventional capacity (and related risks) is a matter of market outcome. The costs of most ancillary mechanisms (e.g. network reserve, CHP premium, FIT) are levied on the electricity price in the form of network surcharges or levies. Some consumer groups are then exempt from these levies leading to an uneven distribution. It is usually large industrial consumer groups who are exempt on the grounds of industrial competitiveness concerns. Details of the regulations vary but as an approximation the larger the consumer is the wider the exemptions get. The ETS regulates differently but it follows the same goal: energy intensive industries are exempt from auctioning and receive allowances for free in order to shield them from international competition. An exception is the costs of the control reserve: here customers using more than 100,000 kWh/a (registered load measurement) have to pay the costs of deviation from their schedule themselves whereas for customers below that boundary (standardized load profile) the costs are levied on the network charges. Another study argues that the different mechanisms not only allocate costs but also allocate risks (that, in turn, also mean costs) in very distinct ways (some risks, however are macroeconomic, i.e. independent of the instrument). For instance, the (2014 version and earlier) EEG shields variable RES from risks of the level and duration of revenue as well as from marketing risks. As the allocation of risks between segments interacts, raising the risks (and costs) may lead to overall declining costs (Matthes et al. 2014, section 2.4.2). However, this needs to keep in mind the different characteristics of variable, capital intensive capacities on the one hand and firm capacities on the other (see section 4.2.2.1 for a discussion on financing and risks of the former).

6.2 Specific distributional mechanisms

This chapter focuses on 'specific distributional mechanisms'. It deals with the allocation of network costs and other levies which are network-related as well as taxes that are directly charged on electricity prices.

6.2.1 Japan

6.2.1.1 Distribution of network costs and challenges ahead

The network is a regulated sector and will continue to be regulated even after legal unbundled in 2020. In Japan all costs of the network service are passed through to the retail companies. The retail company in the competitive sector may or may not pass through to end-use electricity rates that customers pay. The cost of network accounts for 20 to 30% in electricity rates in Japan (EGMSC 2016). The wheeling rate determined by the total cost-of-service recovers the cost of the network.

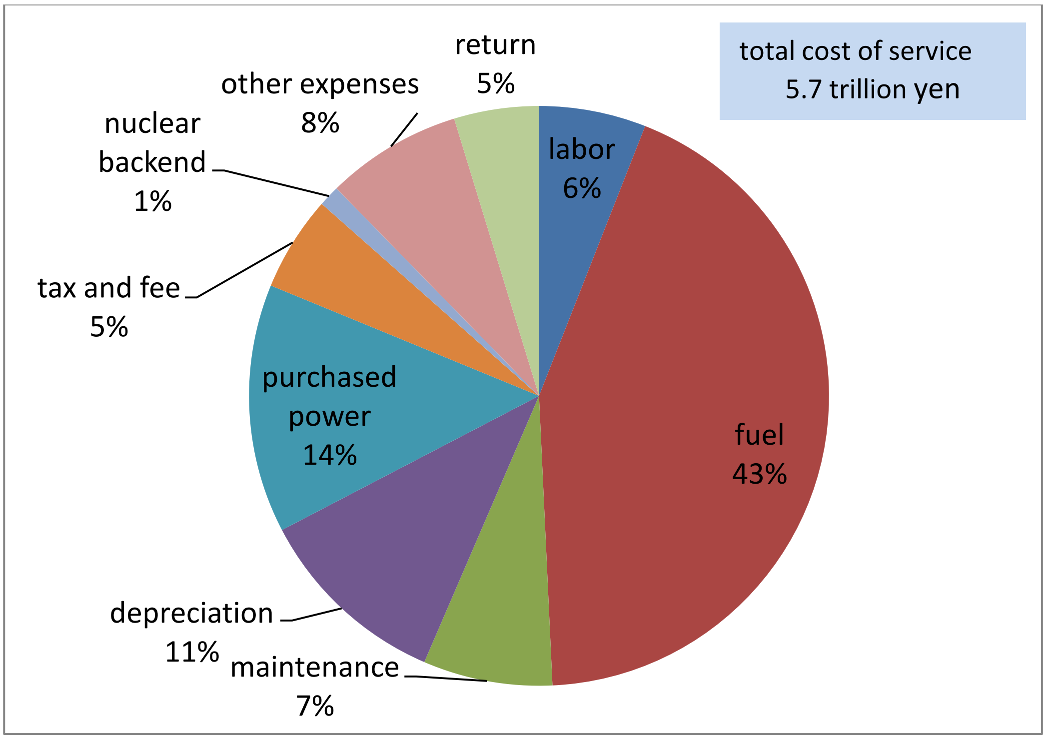
Figure 51 shows composition of total cost-of-service of Tokyo Electric Power Company (TEPCO). Average annual total cost-of-service in the period of 2013-2015 amounted ¥5.7 trillion or €44 billion. To derive wheeling rates, total costs are allocated at first to each sector comprised of 9 sectors including generation, network, supply and general administration. Then, the costs are sorted into network costs and non-network costs. Table 24 illustrates costs pertinent to network services for the case of TEPCO. The costs of transmission and distribution including the cost of substations accounts for 75% of total network costs.

Fixed costs are distributed into three customer classes that are extra-high voltage, high voltage and low voltage customers based on maximum demand. Variable costs are distributed according to volume of generating and receiving power while customer costs are distributed by the number of contracts.

While the fixed cost accounts for 80% of total transmission and distribution costs, the demand charge composing two-part tariff covers only 30%. Allocation of costs also presumes that electricity flows from the high voltage power system to the low voltage power system.

As the market for power evolves, the premise underlying current rate-making of transmission and distribution services is not likely to hold. There is a concern that unbundled generating entities may choose the generating site without considering the cost of maintaining and operating the network.

Figure 51 Composition of total cost-of-service (Tokyo Electric Power Company)



Source: EGMSC 2016

Table 24 Breakdown of Network Costs (Tokyo Electric Power Company)

	cost(100mil.yen)	yen/kWh
dispatching	174	0.06
ancillary	1,408	0.49
transmission	4,060	1.4
transformation for receiving	1,119	0.39
high voltage distribution	3,605	1.24
transformation for receiving	717	0.25
low voltage distribution	1,273	0.44
customer cost	1,915	0.66
supply cost in islands	263	0.09
total	14,541	5.02

Source: EGMSC 2016

The second issue to be addressed is possibility of decreasing electricity demand and the spread of self-generation like prosumers. Part of the fixed cost is recovered from the energy charge. Therefore, it is likely that the fixed cost is not recovered if electricity demand is lowered. This scenario is plausible in light of the fact that the Japanese population has started to shrink and also becomes an aging society. If prosumers increase, so-called death spiral may occur. As prosumer's electricity purchase is little, their burden of fixed costs is little. Little burden induces the spread of prosumers further which is led to further deteriorate the recovery rate of fixed costs. This leaves network utilities with no choice but to increase transmission and distribution rates, setting incentives for customers, in turn, to further increase self-generation.

The third issue is the possibility of increasing reverse flows in the grid from distributed generating sources (DER) such as renewable energies. In the traditional supply system, electricity used to flow from upper to lower voltage levels, i.e. from generating power sources through the network to the customers. This direction of flow was one way. However, recently reverse flows from DER are increasing, which necessitate reconsidering allocation of network costs. This is particularly true for smart grids that incorporate e.g. batteries and for the Internet of things (IoT) can contribute to improve efficiency of overall electricity supply system.

6.2.2 Germany

6.2.2.1 Distribution of network costs and levies

The concession fee is regulated by Federal ordinance (Konzessionsabgabenverordnung, KAV) and the maximum value is fixed dependent on the size of a municipality as well as the kind of customers (§ 2 KAV). That means that there are also less fees resp. also fees at zero for special customers. The payments are paid to the municipalities for the right to use public ways for the network infrastructure which is operated by private companies under state regulation (see section 4.3.2.2).

The costs of the network infrastructure in Germany are compensated for by network charges which are exclusively to be paid by consumers, i.e. the generation component (G component) of network charges equals to zero. The allowed revenue which is subject to state regulation is the basis for the calculation of network charges. The network charges dependent on the voltage level at which the consumer is connected as well as the consumer group (large consumers with quarter-hourly metering of load vs. small consumers with standardized load profiles). Large consumers with quarter-hourly metering of load pay network charges which are mostly dependent on their annual demand peak (given in kW) and the assumed simultaneity of demand. In addition to the kW-based charges large consumers have to pay kWh-based charges (BNetzA 2015b, p. 14). Smaller household consumers pay network charges that are almost exclusively dependent on the kWh consumed. Additionally, these consumers in most cases pay a basic charge. All charges are set by the network operator for his network area based on his costs and the consumer structure. Since there are four TSOs as well as almost 900 DSOs in Germany who have to do their own network calculations, network charges vary quite strongly across the Federal Republic of Germany, spreading from roughly 4-5 €-cents or 5.62-7.02 ¥/kWh up to 9-10 €-cents or 12.63-14.04 ¥/kWh for household consumers (BNetzA 2015b, p. 19–20). By tendency, these regional differences will increase in the future (Hinz et al. 2014, pp. 33–35).

Charges for metering, billing and meter operation are regulated as well although these activities are open for competition and must not necessarily be executed by the network operator itself. Since to date there is no overall detailed statistic on network costs and their distribution (cf. Canty 2015), it is non-trivial to make sound judgements for cost distribution. Yet, there are some rules for reduction of network charges for large consumers and such with atypical demand patterns (§ 19 subsection 2 StromNEV) that lead to a redistribution of costs. According to some stakeholders this needs to be revised because with rising RES shares they don't fit into the system design anymore (bne 2016, pp. 2–4; BNetzA 2015a).

In the scheme of the calculation of network charges there are some exceptions, too. These rules in turn, are one of the aspects of an ongoing discussion on how to fairly distribute network costs (see e.g. BMWi 2015b, pp. 65–68 for parts of that discussion).

There are some cost components that are charged as a surcharge on transmission network charges and carried by final customer. All of these are determined by the TSOs who are responsible for recovering the corresponding costs which ultimately are network related. The cost components are (see 50Hertz et al. 2017c for further information):

- The costs for the provision of control power which was already dealt with above,
- the levy for disruptible loads which is regulated by the AbLaV and accordingly was already mentioned with above,
- an additional levy (based on § 19 StromNEV) to compensate for the lost revenue that results from deductions in network charges to final consumers who benefit from exceptions as well as,
- an offshore levy to compensate the operators of offshore wind power plants for delays in transmission network connection which is regulated in § 17f EnWG.

6.2.2.2 Taxes on electricity

In Germany, there are two kinds of taxes which are charged per kWh of electricity consumed: First, the value-added (VAT) tax is paid by consumers and currently for electricity is at 19% of the net final consumer price (including all charges, levies and taxes). For the VAT, no exceptional rules exist. Second, there is an electricity tax which is regulated by a separate law (StromStG). The regular tax is fixed at €20.50 or ¥2475.88 per MWh. Large consumers can either benefit from reduced taxes or may be completely exempted from the electricity tax. Especially energy-intensive industries are excluded from electricity tax payments (cf. § 9a StromStG) and other companies are allowed to file a request of discharge (cf. § 9b StromStG).

6.2.2.3 Preliminary conclusion

Taken together, there is a similar handling between general and specific distributional mechanisms despite a partly sophisticated structure of the latter (e.g. network charges). As these mechanisms are also levied on the electricity price there are similar exemptions for large electricity consumers as mentioned for general mechanisms. The same is true for the electricity tax. There is no exemption from the VAT. However, as this has to be paid on the electricity price including all levies and surcharges an exemptions from these lowers the VAT accordingly.

Furthermore, large electricity consumers buy their electricity at the wholesale market directly instead of using a retailer (EEX 2017c). That is, they can benefit from the low electricity prices that have occurred in the last years due to the merit-order effect (section 4.1.2.1.2).

6.3 Final customer prices: price components and origin

6.3.1 Japan

6.3.1.1 Contract categories and rate structure

Electric contracts for regulated rates are classified according to electricity usage category, including usage for lighting and industrial purposes, and are supplied based on the “specific retail supply provisions” of the EPCO. Electricity rates are in principle organized in a two-part system comprising demand charges proportional to energy consumption, based on electricity rate unit prices set for each contract category. For such a two-part system, the rates are structured as in the equation below.

electricity rate = basic rate
+ (electricity unit price x electricity consumption)
± fuel cost adjustment X electricity consumption
+ surcharge for renewable energy generation X electricity consumption

For example, electricity demand for lighting purposes is supplied at low voltage to users with contracted demand of less than 50 kW. Since 1974, the year following the first crisis, a three blocks rate system has been adopted for energy charges for lighting service to promote energy conservation. Under this system, monthly electricity consumption is divided into three blocks. The first block is for consumption of 120 kWh or less, which is considered the minimal electricity consumption necessary for daily life, and a relatively low unit price is applied.

A unit price at the average supply cost is applied for electricity consumption in the second tier, and a slightly higher unit price is applied for electricity consumption in the third block. The threshold between the second block and the third block is set at 300 kWh (280 kWh for Hokkaido EPCO) in consideration of typical electricity consumption by general household customers. There is also a low-voltage contract category, which is applicable primarily to small factories.

6.3.1.2 Composition of electricity rates

Table 25 shows as an example the breakdown of actual average cost-of-service of Hokkaido EPCO during the period of 2013 to 2015. Among the items in total costs, the share of fuel and purchased power accounted for more than 40% which was partly because of unexpected low capacity factors of nuclear power plants as a result of suspension of nuclear power operation.

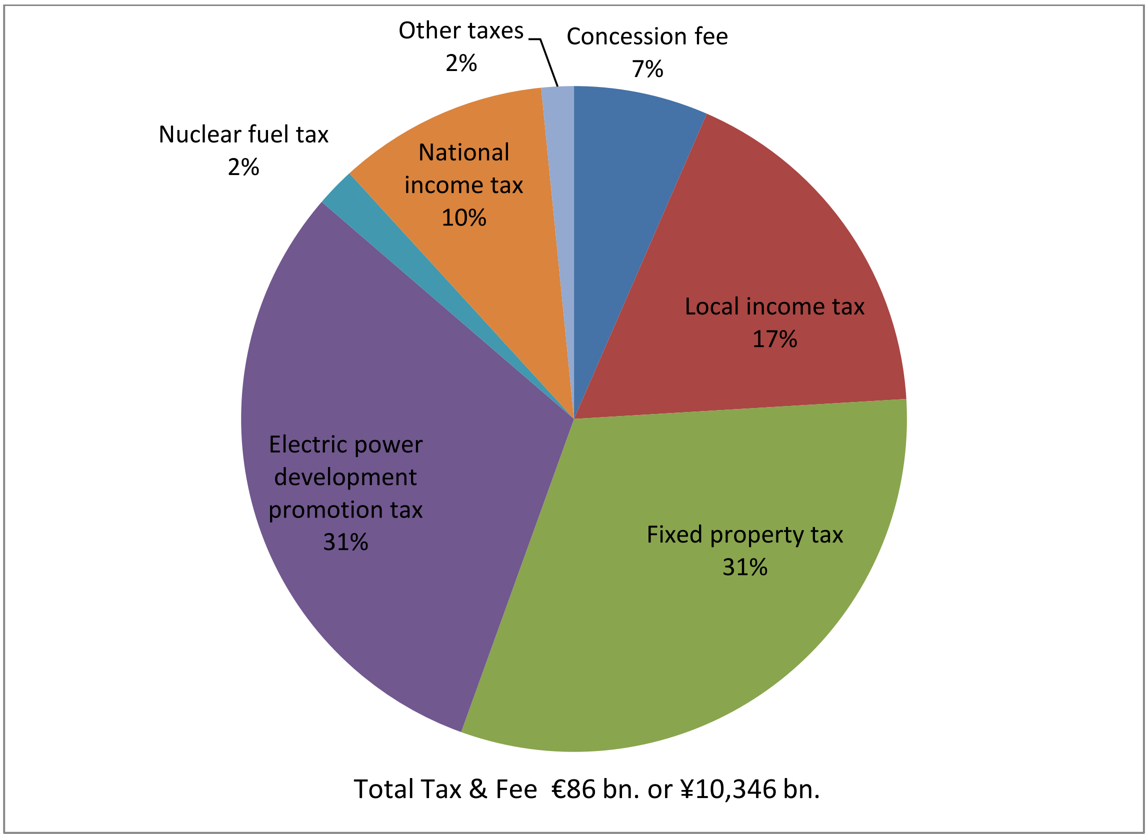
Table 25 Breakdown of Total Cost

Item	¥ or €/kWh	%
Labor	1.68 or 0.014	8
Fuel	6.26 or 0.052	30
Maintenance	2.55 or 0.021	12
Depreciation	2.95 or 0.024	14
Purchase Power	2.73 or 0.023	13
Tax and Fee	1.16 or 0.010	6
Nuclear Backend	0.16 or 0.001	1
others	3.36 or 0.028	16
Total Cost	20.85 or 0.173	100

Source: HEPCO 2017

For taxes there are two types. One is the general tax which is composed of the national corporate tax and the local corporate income tax, the fixed property tax and other taxes such as consumption tax (Figure 52). Another tax is the special tax for electricity business for the purpose of promoting electric power development and the tax for nuclear fuel. In addition, electric utilities have been also paying so-called oil/coal tax which can be categorized as the carbon tax. Furthermore, electric utilities have been expending concession fees like use of river and public domains.

Figure 52 Tax and free expenditure by 10 electric utilities in 2017



Source: FEPC 2016

10 Electric Utilities paid 1,028 billion yen as taxes and fees in 2017. This amount is equivalent to 5 % of total electricity supply revenue.

6.3.2 Germany

6.3.2.1 Rate structure

Final customer prices for electricity consist of a number of price components, some of them already mentioned in sections 6.1.2 and 6.2.2. Especially for household consumers, the share of price components which cannot be influenced by the supply company is quite high reaching around 70% (Leprich 2015, p. 52). The components of the average final consumer prices for households and standard industry consumer was already depicted in Figure 21 and Figure 22 in section 2.2.3.2.2. Price components for industry consumers benefiting from all exceptions are shown in Figure 53. The price data for the household and the standard industry consumer was taken from a statistic of the German association of energy and water industry (BDEW 2017). The data on possible industry exemptions in turn, was taken from the monitoring reports from the German regulatory office (BNetzA und BKartA 2014, pp. 154–155, 2015, pp. 196–198, 2016, pp. 201–203) as well as the transparency data of the German TSOs (50Hertz et al. 2017c). As the data basis for the industry consumers with exemptions deviates and the consumption is different, the values are not directly comparable but tendencies can be seen.

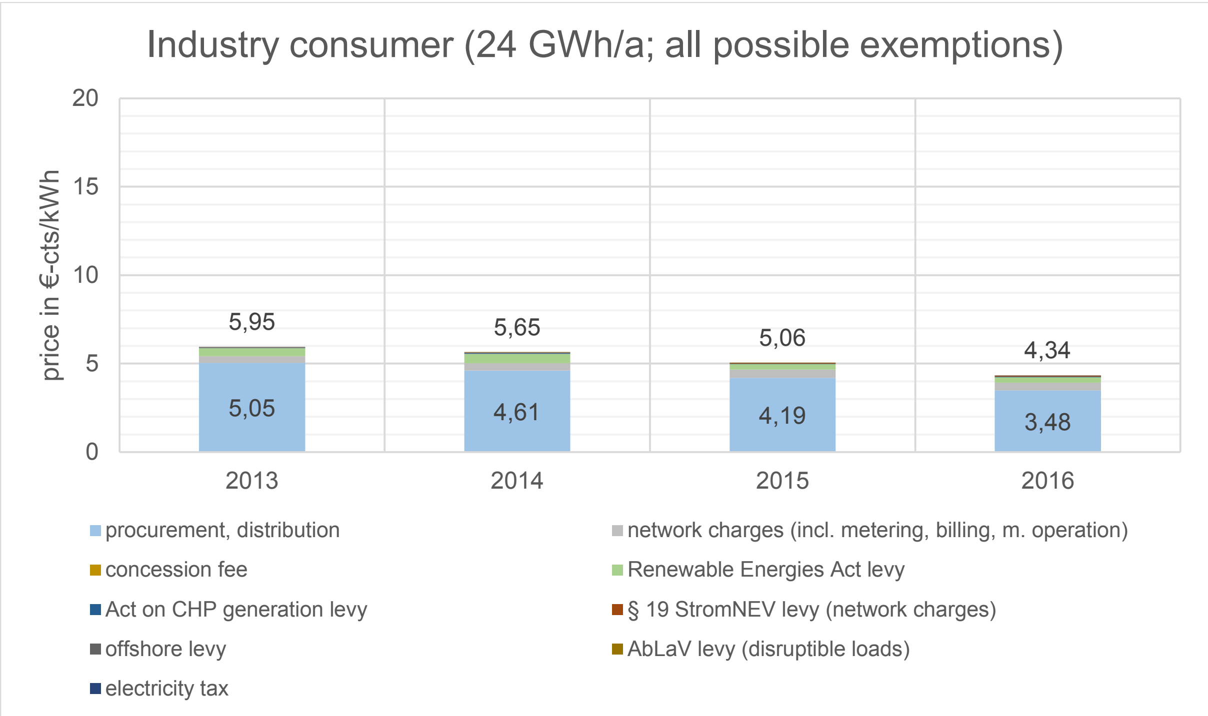
6.3.2.2 Components of prices

The respective price components may vary depending on the location of a consumer (network charges and concession fee), the supply company (distribution costs and margin) or the size and structure of a consumer and its energy demand (especially within the industry segment). For providing an overview on these price components, they are shortly described in the following:

- Procurement and distribution: The price for the procurement and distribution of electricity is the only price component that is competitively determined and is not by regulation. It contains the supply margin of a supply company. For industry consumers, this price component is not shown separately from the network charges in the statistic referred to (BDEW 2017, p. 25).
- Network charges: The network charges are paid by final consumers for the costs of the grid infrastructure. The costs for metering, billing and meter operation are included in the statistics.
- Value-added tax: A value-added tax of 19% is paid by final consumers on the total cost of electricity.
- Concession fee: The revenues from the concession fee serve as a compensation for municipalities for the right of the usage of public ways for network infrastructure.
- Renewable Energies Act levy: The Renewable Energy Act levy serves to recover the total costs (fixed and variable ones) of RES.
- Act on CHP generation levy: The levy from the Act on CHP generation levy compensates for part of the costs of CHP power plants.
- § 19 StromNEV levy: The levy from § 19 StromNEV serves to compensate for the lost revenue that results from deductions in network charges to final consumers who benefit from exceptions.
- Offshore levy: The offshore levy is paid to recover the costs occurring to the operators of offshore wind farms in case of a delayed network access.
- AbLaV levy: The AbLaV levy is paid for financing interruptible loads which are regulated under this ordinance.
- Electricity tax: The electricity tax is paid on a kWh basis due to the StromStG.

Figure 21 in section 2.2.3.2.2 depicted the average amount of the respective price components for a household consumer (connection to the low voltage grid) with an annual demand of 3,500 kWh. From there it can be seen that in 2017 the amount of “policy oriented” taxes and levies (i.e. without procurement & distribution, network charges, VAT) amounts to around 40% of the total electricity price. The prices for an industry consumer was depicted in Figure 22 in section 2.2.3.2.2 as well as Figure 53. The exemplary industry consumer in Figure 22 has an annual demand of 160,000 kWh up to 20 GWh and is connected to the medium voltage grid. The exemplary consumer in Figure 53 has an annual demand of 24 GWh and is connected to the medium voltage grid. Whereas the industry consumer in Figure 22 does not benefit from any exemptions, the industry consumer in Figure 53 does benefit from all possible exemptions.

Figure 53 Average electricity prices for industry consumer with a demand of 24 GWh/a and use of all possible exemption rules



Source: IZES / own depiction; data: BNetzA und BKartA 2014, pp. 154–155, 2015, 196–198, 2016, 201–203; 50Hertz et al. 2017c

This section illustrates the distributional mechanisms laid out in sections 6.1.2 and 6.2.2. Whereas large electricity consumers (Figure 53) are exempt from almost all levies, non-large industrial consumers (Figure 22) and households (Figure 21) are not. Furthermore, the large customers’ exemptions raise the levies of the latter two groups even further to compensate for the loss in revenue. Another effect is also shown in

Figure 53: Large electricity consumers usually buy electricity directly on the wholesale market. Therefore, in addition to the exemptions they also benefit from low electricity prices that are due to the merit-order effect (see section 4.1.2.1.2).

7 Sub-national entities, resource efficiency in cities

7.1 Japan

7.1.1 Status of subnational electric utilities

Historically, Kyoto City was the first public power entity which started hydro power generation in 1891. Since then, electric utilities owned by municipals such as prefectures and cities were established all over Japan.

During the World War II, all electric facilities were acquired by Japan Electric Generation and Transmission Company (JGTC) and nine distribution companies. After the War, JGTC and distribution companies were dissolved and nine vertically integrated investor-owned electric power companies were established. Public power was re-established to make up for lack of supply capability by electric power companies immediately after in early 1950's. In this regime, public power mainly involved developing river and engaged in selling wholesale power generated by hydro power plants to electric power companies. Nowadays, they also own wind and PV facilities.

As of April 2016, there are 26 public power utilities. They have been selling wholesale power to incumbents. They have in total 2,435 MW of generating capacity, of which about 95% is hydro power. Other power sources are refuse-fired, PV and wind power. Annual generation by these power sources is 8,860 GWh. Therefore, the share of public power generation in total generation in Japan is only 1%.

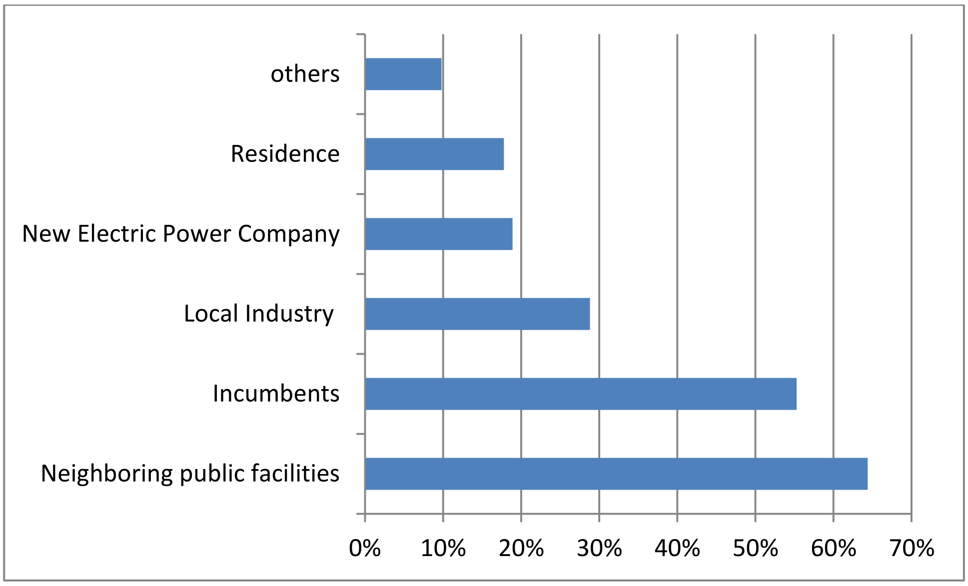
The number of public power entity has been, however, increasing as a result of the Great Earthquake along with the introduction of the FIT system and full liberalization of retail electricity and gas. According to investigation questionnaire in 2013 conducted by the Ministry of Environment, 264 municipalities have already embarked on forming their own energy policies[23]. Motives behind forming energy policies is to 1) tackle with global warming, 2) securing energy supply in emergency, 3) reducing energy costs, 4) securing employment opportunity by activating local economies and 5) creating new industries.

Among various energy sources, PV is most popular. 180 municipalities out of 264 assume it. Others in the order of popularity are woody biomass heat utilization, hydro power generation, woody biomass electricity generation, waste generation, wind generation, etc.

[23] Investigation questionnaire was sent to 1,789 municipalities which include prefectures, cities, town and 23 districts in Tokyo. 985 municipalities responded to the questionnaire.

Assumed purchasers of electricity generated are shown in Figure 54. More than half of municipalities assume supply to neighboring public facilities and selling electricity to incumbents.

Figure 54 Assumed Customers



Source: MoE 2015

7.1.2 Challenges confronting municipality

Energy policies formulated by municipalities have its own significance. They can contribute to solve local problems. However, since Japanese system has been centralized in terms of forming energy policies like METI's policies, there are a number of challenges for municipalities.

Table 26 shows such problems for the municipalities that have already embarked on implementing or initiating the various programs. There are diverse problems which include financial burden, difficulty of securing resources, project profitability and experts. These problems are found to manifest in the steps of preparatory, formulating and realizing a plan.

Table 26 Challenges Facing Municipalities

Challenges	%
Heavy burden of facility and equipment costs	39.4
Securing local resources/energy sources for stable supply is difficult	25
Connectivity with local economic activation and industry development	23.1
Inability to secure economics of the project	19.7
Lack of experts	17.8
Heavy financial burden for municipalities	15.5
Making conditions which enable local entities to enter easier is difficult	13.6
Heavy burden of the costs of infrastructure (own transmission lines, heat pipes)	12.1
uncertainty of entry feasibility	11.7
Efficient maintenance and administration is difficult	10.2
Low cost-effectiveness	9.8
Project management is difficult	9.8
Forming consensus with land lord and local people is difficult	9.8
Pertinent legal regulation	9.1
Role of municipality is not clear	6.8
Entity does not exist	6.8
Securing stable customers in the long-run is difficult	5.7
Demand corresponding to supply does not exist	4.9
Planning facilities efficiently is difficult	4.5
Designing efficient value-added service is difficult	3.8
Getting from support of central and prefectural governments is difficult	2.3

Source: MoE 2015

7.1.3 Citizen's involvement

The first citizens' power plant was born in Miyazaki-ken in 1993. Before FIT system was introduced, more than 390 renewable power units owned by citizens had been already operating. Thanking FIT, development of renewable energies funded by citizens gained momentum. The number of citizens' power units have reached 767 as of November, 2015 (Toyota 2016).

The first wind energy fund established by citizens was organized by Community Wind Power (CWP) in Sapporo, Hokkaido[24]. CWP's mother organization is Hokkaido Green Fund (HGF) which is a Non-Profit Organization (NPO) established in 1999. HGF introduced the "Green Electricity Tariff" program. About 1,000 participants in this program donated 5% of electricity bills every month and planned to build the wind power station. Yet, the procured fund was not sufficient to build the wind power plant which costed 200 million yen. However, private financial institutions were not inclined to finance

[24] http://www.cwp.co.jp/

NPOs. Eventually, they could raise the funds from an additional 200 citizens. With this fund by the citizen, the first wind power plant with the capacity of 999 kW was commissioned in 1999. Since then, 12 wind power units built by similar scheme have been operating.

However, most of developed renewable energy has been PV. This is because the gestation period is relatively shorter than other renewable energies. And financing is easier because business risk is also relatively lower than other renewable energies.

As FIT prices have been lowered over the years, economics of PV projects is deteriorating. Some entities are trying to overcome the difficulty by constructing large scale power plants which brings about lower costs due to economies of scale. Yet, revised FIT stipulates that competitive bidding is to be introduced for large-scale PV.

Typical financing is the above-mentioned anonymous partnership and commercial bank loan. There are other financing options including various bonds and stocks. There are also cases of partnering with municipalities. PV project in cooperation with Iida City in Nagano-ken is poster child of the cooperative project with municipalities.

7.2 Germany

7.2.1 Value creation from RE: more evenly distributed than from fossil fuels

The preceding chapter dealt with the distribution of the costs of the energy transition and focused on specific consumer groups and sector. This section deals with the effects of the energy transition in terms of structural change and takes a more regional perspective. More specifically, it reviews the implications on regional / communal development in terms of local development and value creation.

Hirschl et al. (2010) developed a model of value added and job effects of specific RE-technologies over their life cycle (WEBEE-Model), based on turnover per installed capacity kW. Meanwhile, the model includes value chains for more than 50 technologies (see also Heinbach et al. 2017, pp. 48–50). Focusing on the economic side (i.e. leaving away socio-ecological and institutional aspects) they define communal value added as “the creation of economic values on the communal level” (Hirschl et al. 2010, p. 1). It is composed of:

- Profits (after taxes) of the involved companies
- Net income of the involved employees
- Paid taxes based on the different steps of value-added

In terms of taxes it needs to be noted that in Germany different taxes are raised on the communal, provincial and federal level and tax revenues are split between the levels. For the communal value-added communal business tax and the communal share of income tax is most relevant.

The life cycle of the WEBEE-Model includes for main steps as laid out in Table 27. Summing up across all technologies the largest shares of value added result from the operation phase (operation & profits) of the capacities with 47%. These take place where the capacities are located. The single largest share is production with 39%. The model has been extended to include indirect effects, imports & exports and extrapolate the effects for the whole of Germany. In Germany in 2012 66% of the value added occurred on the communal level. So generally, due to the decentralized nature of RE technologies (especially onshore wind and solar PV) their value-added chains are more distributed than for conventional energies.

Table 27 Main steps and shares of life cycle of RE

Production/assemply of capacity (investments)	39%
Installation (investments, planning, mounting)	14%
Operation (running costs, interests)	24%
Profits (incl. taxes)	23%

Source: Aretz et al. 2013, Table 5.3, p. 33 (own calculation of percentages based on absolute values given)

The value-added approach is an important aspect for areas in Germany that have so far depended on lignite mining and where the energy transition implies structural change. A study for the lignite-mining area of Brandenburg shows that already today twice as many people are employed in the renewables-related businesses than in the lignite business and that this number may double until 2030 in the case of a high share renewable strategy. Here, too, due to the more decentralized nature more municipalities will benefit than it is the case now (Bost et al. 2012, p. 14). Similar results have been derived for the lignite area Rhine Land (Heinbach et al. 2017). Due to the German tax system, however, actors need to be locally based since the benefits from corporate & income taxes appear where the company is located. Furthermore, different assumptions can be made in terms of location of the businesses with regard to the remaining value added steps. Scenarios for the Rhine Land and Brandenburg reveal that both value added and job creation may be twice as high if capacity extension (wind and PV only; without production/assembly) is mainly managed by locally rooted businesses. (Heinbach et al. 2017, p. 9, 37). Therefore, it is important to actively steer RE capacity development (in dedicated areas) and to facilitate financial participation of local citizens (networks, citizen energy, local banks etc.) in order to raise local value added. Further local value added may be gained for a respective community, if they manage to attract production sites, for instance via the facilitation of industrial location of RE-firms and – clusters. (Hirschl 2014, pp. 56–58; Heinbach et al. 2017).

Based on the model an online tool has been developed so that communities themselves can calculate the value added effects from building up and operating RE-capacities. The model uses nation-wide average values for the different steps of value-added. More accurate values for a specific municipality would require case studies to take account of e.g. different taxes and wages levels, different shares of local firms in different regions etc. (AEE; AEE 2015).

7.2.2 Value Creation from Energy Efficiency: vital for emission reduction targets and local development

7.2.2.1 Energy efficiency in Buildings

As already mentioned in section 2.2.4 the energy transition is based on shifting electricity production to (V)RE on the one hand and on energy efficiency on the other. One of the most important segments in energy efficiency is the buildings sector. Therefore, all the above energy and climate change programs include actions on buildings:

- 2011: The energy concepts contains the goal of an “almost climate neutral building stock” by 2050, meaning an 80% reduction in primary energy requirements and covering the remaining energy needs mainly by Renewables (BMWi und BMUB 2011, p. 22)
- 2014: The “National Action Plan on Energy Efficiency” (NAPE) defines “instant measures” and “continuing measures” in three areas: i) efficiency in buildings, ii) efficiency as a business model and iii) raise own responsibility (BMWi 2014a)
- 2015: The strategy paper “Energy Efficiency Strategy on Buildings” establishes different scenarios to reach the climate neutral building stock in terms of combinations of efficiency levels of buildings and related RE-supply and discusses necessary measures (BMWi 2015c)
- 2016: The “Green Book Energy Efficiency” introduces the principle “efficiency first” (in all sectors) in order to shift the focus from supply-side to the demand-side, avoid oversizing of infrastructures and lowering overall system costs (BMWi 2016b, section 4.1)
- 2016: The above mentioned strategy paper “Electricity 2030” (see sections 4.1.2.1 and 4.1.2.2) specifies that the principle “efficiency first” is particularly vital for the local coverage of energy requirements in buildings so that only the remaining electricity requirements need to be produced elsewhere and transported to the buildings (BMWi 2016d, p. 5)
- 2016: An energy efficiency campaign for all sectors based on the 2014 green book’s principles, bundling existing programs and creating new ones (BMWi 12.5.16)

As different combinations of (variable renewable) energy supply and end-use efficiency are possible, the principle “efficiency first” aims at establishing a least-cost-planning approach to find the system-wide optimal level of end-use efficiency. This is particularly important (and complex) in times of increasing sector coupling, i.e. where electricity is also used for heating in the building sector. It therefore requires to estimate the overall system value of energy efficiency in buildings in comparison to other measures, in particular with regard to further extending VRE- and transport capacities. (Langenheld und Graichen 2017, pp. 6–7).

All of the different combinations between RE-supply and end-use efficiency imply an acceleration of the current rate of retrofitting. In the scenario with high efficiency the current rate of retrofit of around 1% per year of the total building stock needs to be doubled and retrofit efficiency also needs to rise (“deep renovations”) (BMWi 2015c, p. 34). Another study estimates an even higher rate of 2.2%/a in 2021-2030 and 2.5%/a in 2031-2050 since a market for retrofits needs to be scaled up in the first years (Bürger et al. 2016, pp. 172-3, Fig. 26).

Regulating the building sector, however, has been particularly difficult. Traditionally, policy has relied on a mix of efficiency-standards (for new buildings and for retrofits) and financial incentives for retrofits. For years the Government could not augment financial incentives to the planned level because the federal government and the Länder could not agree on the distribution of costs. (Allé 2015). Also, attempts to merge the laws on efficiency standards for buildings and on renewable heat use in buildings have recently failed. It would have raised the efficiency standards for public buildings and eased planning processes due to better coordination. (dena 30.3.17; Tartler 2017).

A new approach is to focus on quarters instead on single buildings. The idea is to save costs by increasing the flexibility of the efficiency standards in the sense that it could be fulfilled within a quarter as a whole instead of by every single building. Furthermore, it may be possible to plan the quarter’s own decentralized electricity & heat supply in an integrated approach. (AG Energie 2016, chapter 8; BMUB).

As shown above, all scenarios go along with increasing rates of buildings retrofit. That is, apart from climate change mitigation, energy security and costs savings (see SRU 2008, section 3.4.1), increasing the rate of retrofit also increases local value creation. The methodology on supply chain analysis for renewable energies (see section 7.1) has also been applied to the refurbishments of buildings to determine related municipal value added and job creation. These occur mainly at local crafts involved and their necessary local inputs. And again, the municipality also profits from additional taxes (Weiß et al. 2014). Here, local job creation is estimated to be even higher than from renewable energies since it is more labor-intensive. A detailed analysis for a smaller area within the Lausitz-Region has been scaled up for the whole Lausitz-Region and leads to estimates of 1.4-1.9 times the amounts of jobs that result from the job effects of the capacity increases[25] (Heinbach et al. 2017, p. 9, 40)

7.2.2.2 Energy efficiency in Industry and households

Rising energy efficiency in industry and households can be achieved by introducing more efficient energy consuming equipment. In household these are refrigerators, washing machines, dryers, lightening etc. ("white ware") and consumer electronics ("brown ware") (SRU 2008, section 3.4.5).

In industry cross-cutting technologies (air pressure systems, electric motors etc.) are of particular importance (cf. Hesselbach 2012, pp. 139–281). There is an overlap to buildings as some of these installations concern also building infrastructure (air conditioning, heating, cooling etc.). There still remain some obstacles and energy efficiency measures have not been taken up to the degree necessary (and beneficial for consumers). These obstacles can be summarized as:

- Usually investments concerning the ordinary production task –such as investments for quality improvements – form a conflict with energy efficiency investments as financial capacities of a company are scarce and the core business has priority over other investments (Gege und Heib 2012, p. 231). In addition to that, it may be that companies are simply lacking the financial capacities for further energy efficiency investments (Thamling et al. 2010, p. 27).
- The payback periods of energy efficiency investment measures are usually quite long and can range up to more than 10 years. On the other hand, companies usually demand short time frames of around three or four years for amortization for their investment projects which brings up a conflict (Nissen 2014, pp. 4–5).
- In some cases, companies are not aware of their saving potential that is connected with energy efficiency measures (Brüggemann 2005, pp. 24–25).

To mend these problems, the above mentioned energy efficiency campaign of 2016 was introduced. To implement the 2014 NAPE's principles the campaign builds on the three corners stones of financial incentives, advisory services and information and received additional resources. (BMWi 12.5.16). It aims at establishing business models for energy efficiency services in order to enable a specialized sector with sustained market dynamics (see section 5.2.2.13). Consistent with the campaign the main business areas are seen in information, consulting, energy management and contracting (BMWi 2016b, p. 23).

[25] Positive job effects from renewable energies in the Lausitz-Region are estimated between 400 and 820 full time equivalents, depending on scenario whereas from energy efficiency they are estimated to be between 750 and 1150 full time equivalents.

7.2.3 Green & regional electricity products

As mentioned in section 5.2.2 (supply companies) electricity may be marketed as “green” to create a differentiated product in order to win customers and/or to increase the margin. With the latest revision of the feed-in tariff law in 2017 a new system of proof of origin from specific capacities has been introduced: whereas the previous “green certificates” simply certified that demand from renewable electricity has been created anywhere in Europe, the new system ties certificates to specific installations. So on top of being “green” electricity may be sold as “regional” if supplied customer are within a 50km-range of the capacity (§79a EEG 2017). If a marketer opts for this regulation, it foresees a lower market premium from feed-in since the marketer can get additional revenue (potentially higher than the difference) from customers. By introducing a regional component in green capacities costumers may buy electricity from within the region, i.e. from “their” capacities.

The financial meaning and dimension, however, is not yet clear. The business case for the capacities should be secured by the feed-in tariff in general. If this is not the case anymore due to decreasing tariffs, regional green electricity products may provide a solution. However, this requires an additional willingness to pay of the customers (i.e. above market price). Regional electricity products may enhance acceptance of local capacities though if the local population is able to buy electricity from “their” wind park or PV-system. Sector coupling: going beyond electricity sector

While the idea of sector coupling was first mainly an approach to create new flexibility options to level out the varying feed-in from wind and solar energy, it derives into the solution to decarbonize the transportation and parts of the heating sector (cf. BMWi 2017c, S. 7). This is boosted by the insight that national sustainable biomass potentials developed to be more limited and sufficient import is not an serious option (Repenning et al. 2015, S. 454ff). This leads to additional renewable electricity demands. In case of the indirect electricity usage via electricity derived fuels for transportation, it is assumed that these new fuels will mainly originate from foreign countries (Zimmer et al. 2016, S. 261ff). Securing adequate RES or RES derived fuels imports will be an additional challenge for Germany.

The current system of energy taxes and levies provides a serious barrier for sector coupling. A general overhaul is therefore necessary to set the right incentives or sector coupling will not succeed. There is no level playing field for different energy sources across sectors (Agora Energiewende 2017d, S. 17). Taxes and levies mainly derive from historical evolution. They are neither determined on the comparable basis of energy content nor CO_2-emissions. Due to its complexity and diverging interests this process is still at the beginning. Currently, it is mostly levied on electricity so that electricity is not competitive for heating. One of the largest open question in this context, however, may be the impact of prosumerism (i.e. own production) and related questions on the degree of (de)centrality of the future energy system, their implications for financing infrastructures and market design. This is among the most difficult and most contentiously discussed questions. Still, the future system of fees levies and grid charges needs to accommodate these trends and enable a level-playing field for all flexibility options across all sectors.

So far measures by the government mainly aim at adding flexibility to the electricity system. The development of the grid charge system, in particular for DSM as well as the target model for these and state-induced price components still require more research (BMWi 2015b). The target model aims at a better connection between wholesale and retail market (see section 2.2.2.3) so that final consumers better react to the price signals of the wholesale market. This shall enable better competition of flexibility options, system serving prosumerism, efficient sector coupling, efficient grid use / extension and energy efficiency. Further it aims at fair and transparent distribution of costs (see also section 6).

7.2.4 Smarter infrastructures for coordination and flexibility

With rising decentralized RES- and CHP-plants a more active role of the distribution networks appears necessary (cf. Frey et al. 2008, S. 12ff). Apart from a proactive role by the DSOs in integrating and coordinating RES and CHP, interaction with demand by efficiency measures and DSM was included. Network regulation rules on the other hand still favor capital expenditures, which led so far to a limited adoption of smart grid solutions (see sections 2.2.2.2 and 5.2.2.7). With the current focus on the electricity system, a smarter grid infrastructure and networked electricity production and demand are still the main focus to enhance coordination, flexibility and to reduce system costs.

As a prerequisite to improve the data basis and enable new business cases, the “Law on the Digitization of Energy transition” has been passed (Gesetz zur Digitalisierung der Energiewende). The core is a new “law on the operation of meters” (MsbG) but it also contains relevant changes in the law of energy business, the CHP-law, the feed-in-tariff-law and several ordinances. The law on the operation of meters lays out a gradual smart meter roll-out for consumers as well as RES- and CHP-producers. Consumers between 10,000 and 100,000 kWh/a need to install smart meters until 2025 and the law defines varying cost caps (the smaller the consumer, the lower the cap). Up to today only final customers with a consumption of more than 6,000 kWh per year are obliged to use a smart meter (§§ 29-32 MsbG). Consumer of more than 100,000 kWh per year are individually measured already and need to install smart meters until 2033. RES- and CHP-capacities of 7-100 kW also need to install smart meters until 2025, again with varying cost caps (for RES-capacities of <100 kW cost need to be “adequate”). The installation for smart meters for interruptible loads need to be conducted as of 2017 and is regulated in (§ 14a EnWG).

On a national scale “Smart Energy Showcases – Digital Agenda for the Energy Transition” (SINTEG) in five model regions are funded to innovate technologies and procedures and the digitization of the energy sector (BMWi 2016c). Each region has a specific focus and should serve as a blueprint for a wider implementation across Germany. More than 200 partners committed themselves to working together as part of several agendas, including companies, research institutes, municipalities, local districts and the German states.

In terms of grids smarter technologies should reduce grid expansion and create new flexibilities (BMWi 2017c, S. 26f). This includes new approaches in coordination between transmission and distribution networks. Here again the question on the degree of decentralization steps in. Delays in grid expansion and the issue of missing acceptance for new transmission lines open desires to trade information and communication technologies (ICT) for classic “copper wiring” or at least time-delaying the need for expansion. For distribution grids, however, the abilities of so-called smart technologies to avoid grid extension appears to be overrated (Matschoss et al. 2017, section 4.4).

With new electricity demand from different sectors (transportation, heating), like electric mobility or electric boilers, a smart integration for further future flexibility options is pursued. Electric cars should load their batteries depending on RES availability represented by varying price signals (BMWi 2015b, S. 69). The new role of decentralized CHP together with flexible district heating grids plays an important role in integrating rising shares of renewable energies as it was already laid out in section 4.1.2.2).

7.2.5 Financial participation as a means to increase acceptance

The energy transition is one of the largest restructuring efforts that, in fact, goes beyond mere restructuring of infrastructure but changes the way we produce, consume and live with energy. Denominations like “generation project” or “man-on-the-moon-project” shall illustrate the scale of the task. The Ethics Commission for a Save Energy Supply of 2011 that was mandated by Chancellor Angela Merkel in the aftermath of Fukushima described the energy transition as collective project (“Gemeinschaftswerk”). (Ethics Commission for a Safe Energy Supply 2011). This shows that acceptance of the general public of the energy transition project is indispensable. Acceptance can be reach through participation in the collective project. There are various ways to reach participation (e.g. participation in planning processes) but this report focuses on financial participation[26].

As shown above it is vital for the municipalities that companies are locally rooted in order to gain a significant share of the renewable capacities' value chain. In the case where a wind park is mainly built, operated and financed by the local population who in turn receive the revenues (community project) there is a higher benefit of the local population. Furthermore, the wind park is perceived as one's own contribution to the energy transition leading to a better acceptance of the infrastructure. In the opposite case where the wind park is mainly built with financial inflow from outside (investor project) and where only a small share of the benefit reaches the local community the wind park may be perceived as alien leading to less acceptance. In Germany investor's projects have been quite common in the area of Brandenburg where acceptance problems have been much larger than in the area of Northern Friesland where community projects have been more common (Hirschl 2014, p. 52).

7.2.6 Cities and municipal utilities are the key

Around 70 % of Germanys population lives in cities (BMWi 2011, S. 34). Apart from the concentration of buildings with incorporating energy infrastructures (electricity, natural gas, district heating) further urbanization is expected in the future. While the congested areas in Northern and Southern Germany experience population growth, the Eastern parts of Germany, apart from Berlin, have a declining population. This leads to different challenges for building RE-capacities, energy efficiency and development of pipeline- or grid-bound infrastructures.

Since the 1980s a multitude of federal support programs for municipal energy strategies took place with measurable results in energy savings and CO_2 reduction (BMWi 2011, S. 35ff). But the results have been still too low to reach the set climate goals. The moderate success is caused by complexity of municipal structures, lean financial background and methodical deficits. German cities contain very heterogeneous structures with quarters of different aged building structures, historically different conceptions of town planning, differing energy supplies (naturals gas, district heating), mixed commercial, residential or industrial areas, varying layers of ownership and governance. As mentioned in section 7.2.2.1 the future focus is on the development of solutions for city quarters. This contains holistic approaches (usage of existing infrastructures, decentral extensions, e-mobility, preservation of historic buildings, stakeholder

[26] For other forms of participation please refer to GJETC-study strategic topic 2: Strategic frameworks and socio-cultural aspects of the energy transition

integration and knowledge management) as well as improvement of decentral and district heating technologies (waste heat usage, solar heat, storage).

Municipal utilities often own and manage the existing energy infrastructures across the sectors (electricity, heat, gas). That is, in the energy sector they generally maintain most steps of the value chain (see 4.2.2). Often they also organize public transport and public pools. Some of them even started their own telecommunication branch (DNK 2017, S. 12). Due to their wide range of businesses and deep roots in city infrastructures, municipal utilities should play a key role in the topic of sector coupling in the future energy system.

8 Mutual Comments

The following Table 28 reproduces Table 1 of the summary in chapter 1. It gives a comparison of facts between the energy systems and energy transitions in Japan and Germany.

Table 28 Comparison of facts on the energy system between Japan and Germany

Germany	Japan
Chapter 2	
Liberalization	
Energy markets are fully liberalized; guaranteed network access and transparent network pricing without possibility to cross-subsidize is key; switching trends have increased over the years but are lower in households than in businesses, nevertheless concentration measures are low	liberalization is only now gaining thrust; incumbents still have a dominant position; switching rates are low, esp. in low voltage segment (picture somewhat similar to early stages of liberalization in Germany)
Energy transition policy / long-term plan	
Long-term strategy reaching to 2050; energy transition based on VRE and energy efficiency; long-term goals for GHG reduction, RE-shares and efficiency; RE have reached system relevance	Basic energy plan reaching to 2030 (under revision); future role of nuclear power and RES not yet clear; voluntary GHG goals; RE-shares comparatively low but significant rise in PV-capacities since 2012
Structure of generation systems	
Constant buildup of RES-capacities since 1990's; compensate for start of controlled nuclear phase-out; high shares of coal	Sudden drop of nuclear production due to Fukushima-accident; equal increase from fossil fuels (mainly nat. gas), low RE-capacities
Chapter 3	
Efficient dispatch – Energy market setup	
Exchange model – free trade regardless of network congestions ('illusion of copper plate')	Incumbent's self-supply based on the merit-order still dominating the market; Regulatory instruments to activate the market being introduced.
Comparatively high product variety and trade volumes as well as more players at market (longer history of liberalization)	Market not yet developed; comparatively low product variety and trade volumes
Part of EU market integration effort; but common market zone with Austria will be split in 2018	Regular market splits along former monopoly areas (too low transmission / converter capacities)
Clean dispatch (conventional): CO_2-intensity	
More or less constant decrease between 1990-2015 from 760 to 540 g/kWh	1990-1998 sinking; 1998-2007 rising beyond original value; 2008-2010 steep fall (to around '98 value); 2011-2013 steep rise (all time high) 2013-2015 sinking again but still higher than 1990
Clean dispatch (conventional): instruments changing merit order	
EU ETS: raises marginal costs according to CO_2-intensity (GER as part of EU system) FIT: introduces new capacities at "far left" of merit-order CHP: fix premium per kWh from CHP lowers marginal costs	Depending principally on voluntary efforts by utilities FIT: introduces new capacity at "far left" of merit-order
Chapter 4	
Financing firm capacities	

Focus on increasing system's and market's flexibility to serve VRE (firm capacity as one option within a menu of flexibility options) No introduction of capacity market due to focus on flexibility; instead creation of level playing field for flexibility options through sufficient flexible energy-only market (make them economically worthwhile); various instruments for flexibility	Focus on baseload: open access of existing baseload to newcomers, new incentives for new baseload capacities Various instruments for baseload incl. capacity market as of 2020; obligation for retailers to secure all energy and submit ten-year demand and supply plan annually
Financing variable capacities	
1990: first version of FIT, adapted ever since (capacity shares 2015 of PV 19% and wind 20%, significant biomass); current switch to auctioning hotly debated as it is feared that it may disadvantage small stakeholders	2012: FIT (before: portfolio standard, net metering) 2012-2015: significant increase of PV (capacity share 2015: 7%) but low wind and other REs; now switching to auctioning for the large-scale PV
Management of networks	
Part of European effort to integrate electricity system (see chapter 3) and increase interconnector capacity	Relatively weak network, interconnector management important, therefore included in market design (see chapter 3)
Priority access for RE as part of FIT	No real priority access for RE; concept of "connectable amount"; amount has dropped to zero in some areas
Despite difference to Japan (Germany is hub within Europe): opportunity to increase efficiency by increasing interconnections between countries	Despite difference to Germany (Japan is an island): opportunity to increase efficiency by increasing interconnections within the country
Chapter 5	
Business models: generation	
In General: IPP; with regard to energy transition: RE-investors and/or –operators	Before 2011 some specialized power producers supplied specific regions but with low share; after 2011 market entries increased somewhat but concentration stays high due to integration measures of incumbents (see above)
Business models: wholesale	
Rise of green electricity products since direct market sales are mandatory Direct marketers act as agents for RE-capacity owners who do not market themselves Aggregators bundle flexible loads (DSM) and focus on ancillary services	Various measures including Gross Bidding being introduced to activate the wholesale market
Business models: retail / supply	
Green electricity products used for product differentiation (guarantee of origin since 2017) sector coupling: number of new likely business models (after reform of charges and levies); first incentives in latest FIT-reform (usage of excess electricity in congested areas); municipal utilities seem well-positioned going along with a trend of remunicipalization Prosumerism: new in private households, increasing also for quarters; raises issues for grid planning and finance	A number of new market entries, business models get more diverse; incumbents still own 90% market share

Specialized industries: energy service companies (ESCOs, energy efficiency) once relevant markets are established Non-specialized industries: new possibilities to lower electricity purchase costs as flexibility and efficiency receive remunerations	
Business models: networks	
4 TSO and 875 DSO; incentive regulation scheme; grid connections with EU-neighbors & part of EU-integration effort, incentive regulation, priority access for RES	10 network (T&D) operators and one privately operated T line dedicated to collect wind energy; Regulation based on cost-of-service; long-term fixed power sources (nuclear, etc.) prioritized; access by first-come first-serve basis and inflexible connectable amount
Chapter 6	
General distributional mechanisms	
Efficient dispatch & market price: costs and risks are a matter of market outcome (influenced, in turn, by regulation) Efficient dispatch & charges and levies: almost all other cost (EU ETS, CHP, FIT) are levied on electricity consumption and large consumers are exempt	Efficient dispatch: risks may change due to liberalization for incumbents and IPP alike, raising financing costs
Clean dispatch: as above, costs levied on electricity consumption and large industries are exempt	Clean dispatch: Rising FIT levy due to rising RE-capacities: costs are levied on electricity consumption and large industries are exempt
Specific distributional mechanisms	
Network charges & electricity tax: same principle as general mechanism – levy on electricity consumption and exempt large consumers	Network charges & electricity tax: Focus on challenges of future network pricing under changing conditions; smart grid enable new financing models
Large consumers buy electricity directly at wholesale market, benefit from low prices	
Final customer prices (price components)	
Reiterates points of previous sections: private households and non-energy-intensive business are levied, energy-intensive business are not	Three block rate system for regulated rates: rising unit prices as consumption increases to enhance energy savings
Chapter 7	
New establishment of business models (subsumed under chapter 5)	Business models getting more diverse as diverse companies entering the market (see also chapter 5); Some new municipal utilities have been established but face particular challenges due to centralized nature;
Value creation from RE: more evenly distributed than from fossil fuels (but also depends on tax system and firm structure) Job creation from RE: more evenly distributed than from fossil fuels Resource efficiency in cities: High local level of value creation, in particular for efficiency investments (refurbishments of buildings) Cities as agglomerations of infrastructures that need to be modernized in the course of transition; smarter infrastructures needed for better intra- and cross-sectoral coordination (smart grids and technologies)	

Due to scale of task ('man-on-the-moon-project') it goes beyond mere restructuring; participation is vital and municipal utilities are key

Source: own depiction

In the following sections select topics will be discussed that are either named in Table 28 or follow from there. That is, the above topics are not discussed one-by-one but the topics that follow from the overall analysis and are considered of particular importance to one of the partners for the energy transitions of the respective other. This may lead to the situation that for some topics only one partner has a comment. After that, each partner has the opportunity to react to the others' comment, if deemed appropriate. For a general chapter-by-chapter summary of the report the reader may refer to chapter 1.

8.1 Liberalization and energy transition

8.1.1 Comments from Japanese Partner

Some differences of preconditions for electricity liberalization

To understand various electricity market models adopted in the world, we need to take into consideration the historical background of the electricity supply system. In Japan, the electric utilities had played the role of more than mere profit-making public enterprise. The electric power industry is a typically capital-intensive industry. In 1988, for example, when Japan was growing very rapidly, total net investment in the electric power industry amounted to about 3.5 trillion yen or 27 billion euros, about 10% of the total net domestic investment which demonstrates the fundamental importance of the electric power industry in the national economy. On account of this, MITI (METI) sometimes guided electric utilities administratively to adjust implementation of their investment plans to prevailing economic conditions (Iinuma 1991). Still, incumbents in areas other than three metropolitan areas have been seemingly playing the role of a leading company which has a mission to contribute to local economic development.

In the meantime, a vast number of predominantly municipality-owned Stadtwerke own and operate distribution networks in Germany, which is very different from Japanese electricity supply system. The role of municipality has been very limited in Japan though electric power companies affiliated with municipality are emerging just recently. The fact that there are many small distribution utilities without generating sources seems to be a very important factor in assessing in advance if the wholesale market would work effectively or not. Success of private markets like EEX or organized market overseas seems to be partly depend on the experience of transactions between market participants before the artificial wholesale market is established.

Steps to full-fledged competitive market

Germany opened all retail markets simultaneously in 1998. Meanwhile, Japan at first liberalized the generating sector in 1990 and then opened a class of extra-high voltage sector in the retail market in 2000. It took more than 15 years to liberalize all classes of customers.

There is similarity between Japan and Germany in terms of liberalization. That is, both countries embarked on electricity liberalization without unbundling vertically integrated electric utilities. It is recalled that there was an argument in Japan to negate necessity of unbundling by pointing out that Germany did not unbundle incumbents at the start of liberalization.

However, the history of liberalization is the history of efforts to secure open access to incumbents' transmission lines by new entrants in the market. To secure open access, EU adopted in principle ownership unbundling which is most stringent. Japan adopted legal unbundling. As Japan's incumbents are investor-owned utilities, ownership unbundling is likely to impeach the property right of electric utilities.

Germany is a part of the interconnected power system in Europe which is fundamentally different from the Japanese power system. Though the capacities of interconnectors linking with neighboring power systems may not be sufficient, much larger power system and a single electricity market formed by market coupling are effective for attaining economic efficiency of electricity supply. A deep and wide market can afford to absorb disturbances comparing with relatively shallow and narrow market and isolated power system in Japan.

8.1.2 Comments from German Partner

Liberalization, barriers and market access

Undiscriminatory access to wholesale and retail markets as well as transparent regulation of network fees are prerequisites for electricity market liberalization. Liberalization of the wholesale market in Japan already has a bit longer history but liberalization of retail, in particular for low voltage / households, is still new. Therefore, it may not be surprising that concentrations in the various geographical market areas, inherited from the times of monopoly, are still high (Figure 10) and the low traded volumes at the Japanese Electric Power Exchange (JEPX) show the immaturity of the Japanese market and the early stage of liberalization (section 3.1.1.1). The share of new retailers kept rising though (Figure 11). However, since summer 2016 the share in the extra high voltage segment gets lower again.

Still, some conditions seem to remain unfavorable for new retailers. As retail markets have been liberalized before the transmission / distribution sector, it may be that incumbents are still able to cross-subsidize as it used to be the case in the early days of the German liberalization (see section 2.2.2). This may be one of the reasons why incumbents often win the bids against newcomers in offering competitive electricity prices in the high and extra high voltage segment (section 3.1.1.1). Other reasons are mentioned in the text and refer to the lack of access to baseload capacity for newcomers. This advantage in ownership for incumbents results in lower bids because baseload capacities have (i) low marginal costs and (ii) may represent capacities that are written of, whereas new retailers building new capacities would have to include capital service in their bids. It shows, that it is difficult to create a level playing field between incumbents and newcomers in the event of an unequal structure in ownership.

The large advantage of the incumbent was confirmed by the fact that voluntary measures of the past to let newcomers participate have not succeeded and mandatory measures are now considered necessary as is noted in the text (section 4.1.1.1.1). However, as this is about better access to existing capacities it should not be mingled with the issue of burden sharing of nuclear power, in particular with the costs of the Fukushima accident. Burdening newcomers with the costs of previous accidents not only creates problems of justice, it also constitutes a significant barrier to market entry. Furthermore, the issue of how to distribute existing baseload capacity in order to enable market access for newcomers should be kept separately from the long-term question of what role baseload should play in the future.

An important barrier for newcomers to enter the market seems to be set by the regulation that retailers are obligated to secure energy for 10 years ahead (section 4.1.1.1.3). As newcomers may neither have the financial resource nor the market information of incumbents, this regulation seems to be particularly difficult for enabling market entries. Apart from that it sets incentives similar to capacity mechanisms without having formally decided for capacity mechanisms.

Furthermore, pre-liberalization rates are guaranteed to consumers until 2020 (section 2.1.2) as a means of consumer protection. In other countries rates where subsidized before liberalization and have therefore risen afterwards. Internalization of costs or new investment needs may also lead to rising prices. Therefore, as long as pre-liberalization rates are guaranteed they constitute a price cap. That is, there may be a trade-off between the goals of consumer protection and new market entries.

Liberalization and energy transition: The starting point

Today, Japan is revising its energy system in a time where the world has long engaged in climate negotiations and finally agreed on the Paris-Agreement. Therefore, in terms of long-term planning two major difference between Germany and Japan can be identified: First, when energy market liberalization was planned in the 1990’s and 2000’s in Europe and Germany, the policy and research community alike where largely unaware of the energy transition's implications for market design. That is, energy market liberalization back then and energy transition today were two distinct issues, now requiring another wave of market design reforms to tailor for the latter. Secondly, high payments to operators of renewable capacities in Germany were necessary in the 1990's and 2000's to enable niche applications whose economic outlook was not that clear at that time. In other words, technologies had to be develop first (whose learning curve is being paid off today), before the energy transition could gain pace.

For Japan, the situation appears quite different. Firstly, carbon reduction requirements and consequences for the energy sector are nowadays well-known as the Paris Agreement lays out the scale of necessary structural change in the generation segment. Secondly, significant cost reductions in variable renewable energies (PV and onshore wind, offshore wind to some degree) and storage technologies in recent years allow for much clearer strategic decisions within the portfolio of low carbon technologies. Taken together, energy market design reform in Japan has the opportunity to take these factors into account during the process of liberalization. In other words, this provides a significant opportunity to tailor the electricity market design to the needs of liberalization *and* to a low carbon energy system at once. Furthermore, variable renewable energies (VRE) have broadened the set of available technological options.

8.1.3 Reactions to comments

8.1.3.1 Reactions from Japanese partner

For the country where vertically integrated investor-owned electric utilities were reginal monopolies, it is formidable task to create the equal-footing markets for new entrants. Break-up is one way but it is likely to impeach the property right of investors. Therefore, regulators cannot help introducing various instruments to make the market work. Yet, liberalization originally started to aim at reducing the cost of regulation and replacing with dysfunctional regulation with competition. In reality, however, competition has not matured to the extent of replacing regulation. It is the fact that regulator's role appears to continue to make new regulations to get the imperfect market work.

As pointed out, conditions facing new entrants remain unfavorable in both wholesale and retail markets from the standpoint of contestability. Retail companies are mandated to secure supply sources through own generating plants, bilateral contracts and purchase through JEPX. This requirement appears to indicate the risk-averse attitude of the regulator toward the retailers in terms of securing adequate supply.

In the meantime, various measures such as gross bidding and capacity demerger are being introduced to remove barriers for new entrants as stated in sections 3.1 and 4.1.

The regulated retail rate is the transitory measure until 2020 by which workable competition is expected to be realized. However, there is no definite metric to determine whether competition is working or not. For example, the switching rate is used to evaluate the performance of retail competition. Yet, it is only one of many elements in gauging the degree of success for retail competition.

It is true that liberalization and energy transition are different things. The Partner's comment suggests that Japan is in a good position to do two things at the same time. However, we are yet to have a clear vision for the future.

8.1.3.2 Reactions from German partner

In terms of preconditions for liberalization maybe they are not so fundamentally different in Germany. Maybe the difference is more in timing since in Germany liberalization took place 20 years before the energy transition and in Japan both needs to be done at once, as was pointed out before. There are similarities, too, as in Germany "true" liberalization was an arduous task as well that had to be pushed through against much political resistance. In particular, this was true for the integration of RES resulting in specific regulations granting priority access to these sources. The great chance for Japan is now, as was pointed out, that the needs of energy transition may be taken into account right away.

In terms of the different conditions between Germany and Japan (hub in the middle of Europe vs. island state) it may be true that Germany has additional options to integrate VRE. However, as pointed out in section 8.6.1 below, it appears that Japan may gain from the enforcement of its networks and Germany, too, had made the experience that the scope for integration is usually greater than previously thought.

8.2 Long-term energy planning and systemic issues

8.2.1 Comments from Japanese Partner

Direction of long-term energy policy

In Japan's energy policy, nuclear has been most important core energy in the portfolio of generating plants. Japan is not endowed with energy resources so that energy self-sufficiency is extremely low, 9% in 2015 including nuclear. Therefore, security awareness always has been laid in the center of energy policy-making.

Japan does not have a clear long-term energy vision now. This is mainly because the role of nuclear power in generation mix remains uncertain. The government's energy plan does not indicate that the weight of nuclear power in generation mix is decreasing nor that the share of renewable energies is increasing significantly to such level comparable to German's plan.

Germany has a definite plan to phase out nuclear power triggered by the Fukushima's nuclear incidence and has determined to pursue variable renewable energy (VRE) development. VRE is expected to be a dominant energy like oil in the post-war era in the history of the energy economy. The role of conventional power sources is therefore to be changed and expected to serve renewable energies, which is very different from Japanese system at least for the foreseeable future.

To move to the new supply system, however, significant costs are likely to arise. VRE meets the requirements of energy policy that are economics, environment, energy security and safety. VRE has been literally becoming qualified energy to meet the requirement as economics has improved significantly recently. Yet economics tends to neglect externalities. As emissions by fossil-fuel power plants and the cost of nuclear accidents imposed on society, VRE-based energy system also entails externality. Variable cost of VRE may be free of charge but strong infrastructure is needed to sustain VRE. To build such infrastructure, huge costs are called for with the consent of the public which is sometimes severe hurdle for utilities.

Constraints of the synchronized system

Germany's target for renewable energies in 2050 is 80% while Japan's target in 2030 is just above 20%. Technically, given low capacity factors for VRE, required installed capacity will be huge for Germany. Given also the power system being interconnected with neighboring countries, huge amount of electricity generated by wind at night or PV in the daytime may flow into other systems. If the share of renewable energies in total electricity generation exceed certain threshold, 20% to 30% for example, thermal units are frequently required to ramp up and down for balancing the system. Germany's situation now is in such situation. However, if the share reaches such high level as 80%, then absorption of excess generation would be daunting task for not only Germany also for the other systems interconnected.

Suppose that the maximum electricity demand is 80GW and load factor is 60%. Then, annual electricity consumption will be 420 TWh. If the share of wind is 80%, then wind will have to supply 336 TWh. Assuming that capacity factor is 20%, the wind capacity needed will be 191GW. If all wind units generate simultaneously, then excess generation would be 111GW assuming electricity demand is 80GW. Suppose also that there is sufficient capacity of interconnector between Germany and France. As the peak demand in France is about 90. It is impossible to export such excess generation into French system. France cannot absorb technically such excess generation in Germany (Abe 2016).

8.2.2 Comments from German Partner

Long-term planning and emission reductions

Investments in the energy sector are typically long-term, in particular for large generation units. Therefore, the basic energy plan needs to give clear guidance on the carbon reduction requirements in order to avoid stranded assets. This is particularly important as the framework is now fundamentally changing in the course of liberalization where investors are supposed to take over the risks and benefits of their own investment projects.

The Fukushima accident led to a significant rise in share in generation from fossil capacities from 63 to 82% in the period 2010-2015 (section 2.3). It therefore also poses a particular challenges in terms of energy and climate policy planning (apart from the fact of a threefold catastrophe of an earth quake, a Tsunami and the nuclear accident). As investment decisions on new capacities are now particularly urgent, it makes it all the more necessary to define targets and timetables for emission reductions that translate the Paris-Agreement into the conventional segment of the energy sector to provide the necessary framework conditions for investments. So far the current basic energy plan does not seem to do that. Therefore, the current revision of the basic energy plan should provide for long-term goals.

So far, the industry (including utilities) agreed to a voluntary intensity target that corresponds to the long-term industry outlook. However, this reaches only to 2030 and is clearly less ambitious than the Paris-Agreement. It could be investigated whether the Japanese carbon tax could be raised to the necessary levels. Alternatively, it could be investigated whether the local Japanese emission trading schemes could be scaled up to a national scheme and whether it could be designed in a way to provide timely and sufficient investment signals (section 3.2.1). So far, the European emissions trading scheme has not succeeded in doing so (section 3.2.2.1).

Long-term planning and the role of Nuclear

The large question in Japanese energy policy is whether or not to pursue the nuclear path. Clear guidance is of utmost importance here in order to avoid stranded assets since nuclear energy requires the largest and most long-term investments. The current basic energy plan, however, leaves this unanswered. Instead, the current 2030-goal for low-carbon energy includes renewable energy and nuclear interchangeably. Decisions on the future role of nuclear also touch upon the future role of other energy source, in particular VRE, and give rise to a number of questions, in particular to system compatibility of VRE and nuclear energy. Other questions are dealt with below.

At first sight, the self-evident answer to the question on whether to follow the nuclear or the VRE path is to do both. However, baseload and VRE require different energy systems in the long run. Therefore, rising shares of nuclear and VRE in the same system lead to incompatibilities at one point. Whether a system is based on baseload or VRE is not a given but rather a matter of strategic choice. Germany is currently changing from a baseload to a VRE-based system. However, there are path dependencies and Investment cycles matter to avoid stranded assets. The current high investment needs in Japan would provide an opportunity for a similar shift if Japanese policy wishes to do so. Also, Japan has high shares of gas and pumped hydro capacities (Figure 7) providing a valuable source of flexibility. That is, the energy system appears to be well-suited for high VRE-shares. In any case, clear direction from the long-term plan would be decisive in order to provide investment security.

Furthermore, the German experience shows that “possible” VRE-shares have been higher than previously thought and have been integrated without compromising energy security. This was due, in part, to a necessary learning process in terms of grid operation as well as changes in market design. The other part may have been due to skepticism of the (previously) integrated network operators towards new technologies and stakeholders (see section 4.2.2). However, the rising flexibility requirements led to the point where adaptations of the energy system became necessary that required an overall assessment of necessary changes in market and system design. As one outcome, there is a need for firm – but not baseload – capacity. Firm capacity is just one among a number of flexibility options to accommodate VRE and needs to be highly flexible. (section 4.1.2.1).

In the Japanese system, a strategic decision needs to be taken as investment needs are currently high. Then, specific instruments can be decided upon. So far, however, there is no such decision in the basic energy plan but a number of specific instruments are planned or have been decided upon to accommodate baseload capacities. Among the instruments under consideration there is a baseload market (to be established in 2019) and a capacity market (to be established in 2020). In a non-fossil value market (to be established in 2019) all non-fossil power sources (i.e. RE and nuclear) may be used for the fulfilment of the 2030-target interchangeably (section 2.1.4). In addition, there is the above mentioned obligation for all retailers to secure energy for the next ten years. The latter in itself has the impact of a capacity mechanism. As it was mentioned before, it is unclear whether these instruments just serve to better distribute existing baseload capacity for better market access of newcomers or whether this already predetermines a continued focus on a baseload system. If it is the latter, the introduction of specific instruments prior to a clear decision on the future role of baseload in the system incurs the risk of possible technology lock-ins, path dependency and stranded investments.

Long-term planning and the role of renewable energies

As for nuclear energy, a vision for the future role of renewable energies is necessary. For the reason of compatibility mentioned above, this is particularly true for VRE. Germany did not have a spelled out vision at that time but the techno-economic outlooks and the systemic consequences where less clear at that time.

Since 2012 Japan was able to increase its growth rate of installed PV capacity by introducing a feed-in tariff. However, there are no comparable growth rates for onshore wind energy so far even though it is the lowest cost renewable energy. Several factors are mentioned such as lack of transmission lines, low level of FIT-rates and environmental impact assessments (section 4.2.1).

In terms of renewable energy potentials there is hardly any mentioning of geothermal and installed capacities have been low throughout the years even though Japan seems to have high potentials of this energy source. Furthermore, other sources like wave and tidal energy may be options for Japan although these technologies are still in an early stage.

Japan has successfully introduced an FIT-system but is now introducing auctioning in order to save costs. When changing the instrument, it is important not to compromise growth rates of installed capacity unless this is an explicit goal. If it is an explicit goal it should be stated as such in the basic energy plan. Therefore, instrument design is important. For the issue of cost comparisons between VRE and other technologies – namely nuclear – the reader may refer to section 8.4. Furthermore, it needs to be noted that an FIT is designed to cover the full costs whereas the contribution margin in an energy-only market depends on the scarcity situation of capacities in the market (this may be different between Germany and Japan as there are conventional overcapacities in Germany). For details on the German discussion for cost saving and market integration, see sections 4.2.2.2.5 and 4.2.2.2.6.

The issue of limited compatibility between baseload and VRE-capacities also raises the question whether the interchangeable treatment of renewable and nuclear energy as low carbon energy for the 2030 goal is appropriate. Despite the different system requirements laid out above, the retailers' requirement to provide 44% of low carbon energy in their portfolio by 2030 may be fulfilled by nuclear *or* renewable capacities, i.e. by the *sum* of both. The same interchangeability issue applies to the planned market for environmental values where the low-carbon-property of both shall be traded. (sections 2.1.4 and 4.1.1.1.3).

8.2.3 Reactions to comments

8.2.3.1 Reaction from Japanese Partner

Japanese energy system is not necessarily market-based but rather the type of command and control. The basic energy plan shows direction of our energy system that investors take into consideration in planning the future. Current ambiguous and uncertain picture of energy future is risky for investors, which is likely to hinder investment decisions necessary to maintain existing facilities and building new ones. Even though it is politically sensitive, the key is nuclear power. The role of nuclear power generation must be clarified in order to find the path to the future. There are already huge sunk costs for nuclear power including reprocessing plants and even more if the decision is delayed.

Regarding CO_2 reduction, discussion is going on at the government level. The carbon tax and emission trading are on the agenda. Increasing the tax level and expanding the emission trading are major options to tackle with climate changes. Yet, simple comparison of carbon pricing with other countries will be misleading. This is because implicit costs have been already imposed on emitters in Japan. The voluntary efforts of electric utilities (see section 3.2) is an example.

It is definitely correct that rising shares of nuclear and VRE in the system lead to incompatibilities at one time. However, it seems that we are not moving to either nuclear or renewable energies. Rather, we are moving to the balanced generation mix without relying too much on the specific energy source.

As pointed out for renewable energies, the growth rates for wind and other renewables were low comparing to PV. Therefore, the government revised the renewable policies. For example, development of geothermal energies is now allowed in the national park by relaxing the environmental regulation.

8.2.3.2 Reaction from German partner

In terms of external and infrastructure costs of (V)RE it is true that they require the buildup of some new infrastructures. However, in Germany some replacement of grid infrastructures is required anyway within the normal investment cycle and some others are required due to the common European electricity market. That is, there are multiple benefits to new infrastructures and when trying to determine the integration costs of (V)RE, it needs to be distinguished which of these costs are originally triggered by (V)RE themselves and which investments would have taken place anyway or in a similar form due to the common electricity market or the normal investment cycle.

Furthermore, the amount of infrastructure costs also depend on the *mix* of a given amount of VRE-capacity. The PV-led capacity increases of the last years in Japan imply comparatively high simultaneity and variability of electricity flows compared to a situation with a broader mix between wind and PV. A broader mix implies greater complementarity (i.e. the wind blows when the sun is not shining and vice versa) and therefore fewer needs for networks and flexibility options for a given overall VRE-capacity. Put differently, integration costs per kW of VRE installed capacity would be lower if it was more evenly distributed among the technologies.

In terms of cross-border electricity flows from VRE, raising flexibility of the system through various flexibility options is at the core of the current reform efforts in Germany (see sections 4.1.2.1.1). The very simplified calculation ignores that. The idea of e.g. sector coupling, storage etc. is to absorb of what currently appears as “excess” electricity and to lower cross-border electricity flows. Flexibility is key. Furthermore, as Germany is part of the European integration effort the amount of cross-border flows depend on the scarcities in various countries and not just one neighbor. The issue of increased variability and associated electricity flows is well-known in the European research community and a number of large-scale research efforts using scenario approaches and sophisticated modeling tools deal with the issue (e-Highway2050 2013; Weyant et al. 2013; Knopf et al. 2013; Holz und Hirschhausen 2013; Capros et al. 2013). None of the results of these projects, however, support the above numbers.

8.3 Role of energy-only market

8.3.1 Comments from Japanese partner

Is energy-only market effective for adequacy?

In moving from the traditional electricity supply system to market-based competitive system, there are many challenges. Whether price signal would work effectively or not in terms of securing adequate capacity is one of major concerns. Some ISO/RTOs in the US introduced capacity markets while there are some entities which adopted energy-only market. ERCOT in Texas with a little modification, Nord Pool and Germany are those which adopted energy-only wholesale market. After all, either short-term marginal cost pricing or long-term marginal cost pricing is the unresolved issue in economics.

In Germany, the power system dependent on VRE is requiring flexible capacities including flexibility on the demand side. Therefore, there is no role model as the capacity market fitting Germany since there is no such precedent. This is one of reasons why Germany sticks to energy-only market and adopted strategic reserve (4.1.2.). Germany’s decision is a lesson for other countries in which the share of VRE is increasing or is expected to increase. Existing wholesale market did not assume large quantity of VRE flowing into the market.

As the share of renewable energies with zero marginal cost increases, the wholesale price is likely to decrease further given electricity demand. Then, even investors in renewable energies may not be able to recover the fixed cost since producer's surplus is likely to shrink. Therefore, even missing money problem for renewable energies could be given rise to.

For investors, energy-only market is risky because of unpredictability of recovering investment. And it may be too late when recognizing necessity of securing capacities at the time price spikes. It will be also a challenge to monetize the value of flexibility of power sources in the exchange market.

In Japan, we are yet to establish some capacity mechanism starting in 2020. Policy-making tends to be conservative in Japan due to risk-averse nature. For example, there are two options for the case of the capacity market. One is centralized and another being decentralized. Generally, the network entity procures capacities in the centralized system while each retail supply company is required to secure capacity individually in case of decentralized system. From the standpoint of security, policy-maker would think that centralized one appears to be more secured. This is particularly so in such a country like Japan where socio-economic system is highly centralized.

8.3.2 Reactions to comments

8.3.2.1 Reaction from German partner

In terms of energy-only market and firm capacities, section 4.1.2.1.2 shows that the German conventional segment is characterized by inflexible overcapacities and a need for structural change. Since firm capacities need to be flexible and since these are just one option from a whole menu of flexibility options (demand side integration, storage, regional and sectoral integration – see section 4.1.2.1.1) the primary goal is to level the playing field for all these options. The concern for German policy makers is that capacity markets have a conserving effect and therefore may be a hindrance to that. The European Commission had similar concerns (as well as on the grounds of state aid) and offered a compromise proposal (see section 4.1.2.1.2.2).

In terms of energy-only market and flexible capacities and VRE there are two reactions. One is that the measures of the previous paragraph (phase out conventional overcapacities, encourage all flexibility options) reduce price drops in times of high VRE supply and enhance financial sustainability. This enhances financing for all technologies (VRE and flexibility options) on the energy-only market. Secondly, VRE as capital intensive technologies do require different financing models than a purely marginal cost-based system (as the energy-only market provides) in order to allow bankability (see section 4.2.2.1). This is particularly true as the remaining framework and structures are still skewed towards the conventional system (insufficient carbon pricing, high must-run etc.).

8.4 Costs and risks of nuclear energy in liberalized energy markets

8.4.1 Comments from German Partner

The issue of costs of nuclear energy is not mentioned very prominently in the report. However, the denomination as a low cost energy vis-à-vis renewable energies as well as the changing regulatory environment due to liberalization requires some comments from the viewpoint of the German partner. These refer to questions of accounting for the costs and risks of nuclear and who bears these costs and risks in a liberalized electricity market.

On the issue of *how* to account for costs of nuclear energy, policy makers generally aim at minimizing cost. If fossil and nuclear energies are meant to play a role in the energy transition and if renewable energies shall compete against those technologies using economic instruments, than the basis of economic comparison becomes relevant.

Levelized cost of energy for 2014 and 2030 are shown in Table 10. For 2014 the table shows lower costs for fossil fuels than for renewable energies and even lower costs for nuclear energy. However, learning curves (i.e. cost reductions) are the highest for VRE, significantly reducing the gap in 2030 (according to the text, a CO_2-price of $35/ton was assumed to internalize external costs). The costs of nuclear, on the other hand, are estimated to rise for 2030 as they include the government's 2015-estimate for the costs of the Fukushima accident of ca. 9 trillion yen (ca. 67 billion euros). Meanwhile, however, the government has more than doubled its own estimate to 21 trillion yen (ca. 174 billion euros). Therefore, an updated LCOE would be necessary to judge whether nuclear can really be judged to be the cheapest source of energy. On top, other sources calculate the costs of Fukushima to be 50-70 trillion yen (414-580 billion euros) (japan times 2017). Another source claims that TEPCO itself has voiced that it is not able to estimate the total cost (Spiegel Online 2017). In addition, the costs of "normal" dismantling and nuclear waste disposal need to be added to the costs of the accident (or any future accident, weighed with its likelihood of realization) as well. These can said to be equally uncertain. Taken together, it shows that there are costs attached to this technology that are particularly uncertain and potentially large. It also makes comparisons on an LCOE-basis difficult. At least some more LCOE-estimates from other sources (also for the other technologies) should be used for comparison.

The second issue is *who* bears the costs / risks of nuclear energy in liberalized energy markets. The previous paragraph has shown the specific cost risks that surround nuclear energy investments, in particular with regard to long-term risks. The next question is whether private investors are able to bear those cost risk in a liberalized energy market – as they theoretically should. Despite being built before liberalization, the "big four" utilities in Germany where required to build reserve funds for dismantling and nuclear waste disposal. However, part of the funds have been handed over to the Government together with the responsibility for nuclear waste disposal. If those costs turn out to be higher, they will be paid by the tax payer. As no disposal site has been chosen yet, the costs are largely unknown. One may argue that historically, these additional costs of nuclear are taken over by the state because most nuclear capacities have been built and operated in pre-liberalization times (in fact, the utilities did argue that way). In a liberalized market, however, private investors would have to bear these risks or use distribution mechanisms like insurances.

For Japan, Table 25 does include cost for "nuclear backend". However, given the discussion on cost estimates above it appears that these are also outdated numbers leading to the question whether or not all long-term costs are included. Therefore, the issue raises the broader question of how to account for and treat the costs of nuclear energy in liberalized energy markets.

8.4.2 Reactions to comments

8.4.2.1 Reactions from Japanese partner

The cost estimates for generation technologies always involve many parameters and assumptions. Therefore, it seems that the estimates are merely rough numbers. Given uncertain costs related to Fukushima's decommissioning costs and compensation costs and unopened reprocessing plants, the cost of nuclear power generation is full of uncertainty. The numbers cited in the text was made in 2014. Relative price among generation technologies changed greatly recently. Revising LCOE is called for to evaluate each generating technology.

Who bears the cost of nuclear is a critical question. If it is simply one of the generating technologies, then investors should bear all costs in the competitive market. Yet if it is public goods from the standpoint of energy security and owned by the nation, then the public must bear the costs. Yet, the nuclear power plants have been owned and operated by investor-owned electric utilities in Japan. It can be said that utilities have been playing the role of public enterprise for the country.

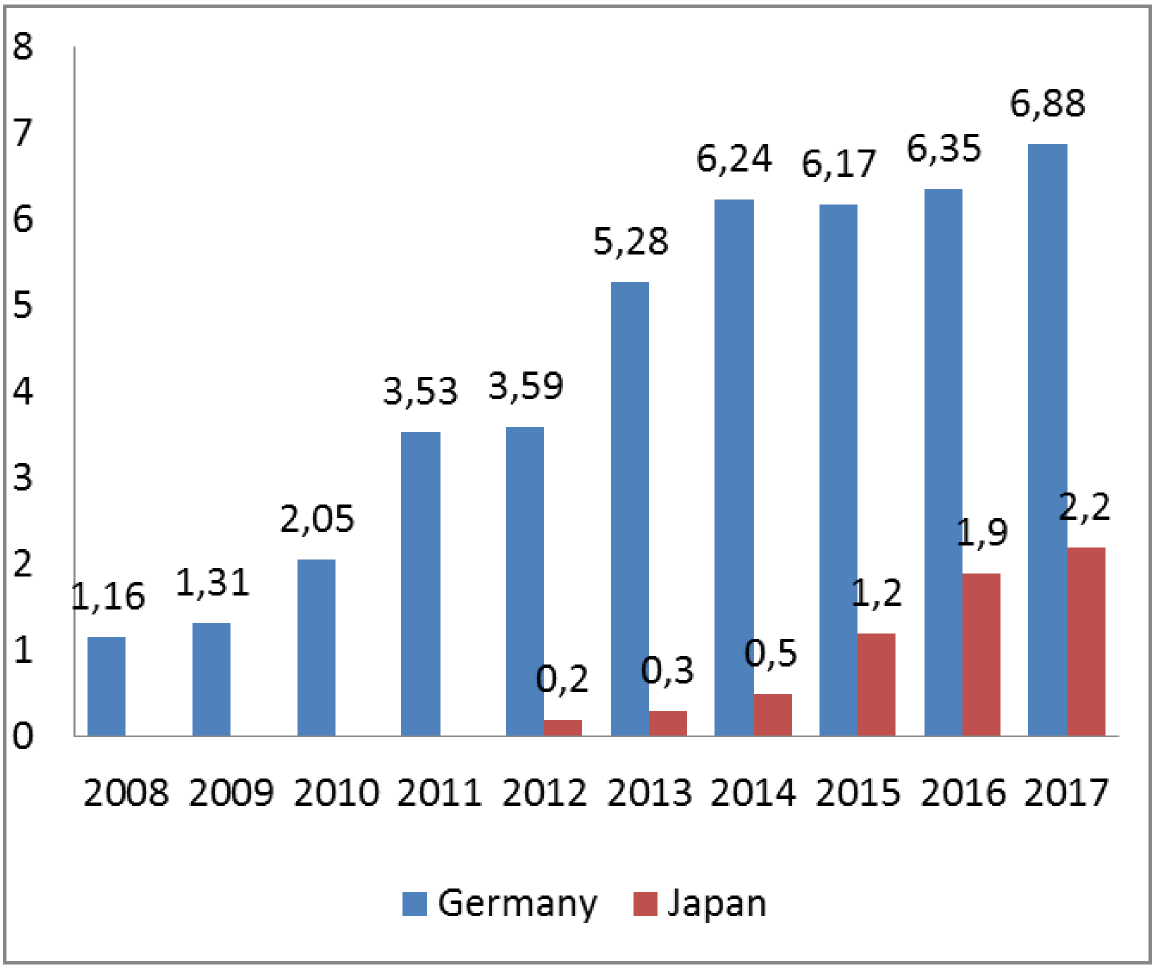
8.5 Financing variable capacities and public acceptance

8.5.1 Comments from Japanese partner

Public acceptance of surcharges associated with renewable energies

Remarkable increase in renewable capacities in wind and solar led to soaring renewable surcharges in Germany. The Surcharge in Japan has also started to accelerate recently though the level of surcharges is about one-third of German's surcharges (Figure 55). In 2017, the surcharge in Germany accounts for about 23% of average unit price of 29.16 cents (Figure 21).

Figure 55 FIT-Surcharges in Germany and Japan (€ ct/kWh)



Source: Table 22, Figure 21

Annual subsidy level in Germany is 20 billion euros in 2015. This amount corresponds to the level of the subsidy in Japan in recent years. According to BDEW's forecast, annual subsidies is reaching 30 billion in 2020 due to increased off-shore wind capacities (BDEW 2016). 30 billion euro is also the annual subsidy level in 2030 in Japan (ANRE 2017e).

To justify these costs to promote renewable energies in Germany and Japan where electricity prices are relatively high internationally, consent of the public and positive net social benefit which is very difficult to quantify are necessary conditions for supporting energy transition.

8.5.2 Reactions to comments

8.5.2.1 Reactions from German partner

As shown in section 4.2.2.2.4 the overall level of payments (i.e. the absolute amount) in Germany is determined by the principle of differential costs. This overall level has been rising due to a number of reasons. One is rising capacities. Another is decreasing electricity prices at the spot market since the overall amount to be paid is the difference between the level of payments to the capacity owner and the revenue from the renewable electricity sold at the spot market. That is, differential costs may rise over the years due to sinking spot market prices despite lower payments to capacity owners. Furthermore, as older capacities indeed receive higher payments this may be looked at as technology development costs (for other technologies – namely nuclear – this has been paid via taxes instead of the electricity price). When dividing these absolute overall costs among the consumers via a surcharge on the electricity rate (displayed in Figure 55) a distributional aspect comes in: energy intensive industries are usually exempt on the grounds of international competitiveness, further raising the levies for the non-privileged consumers (see sections 6.1.2.5, 6.2.2.3 and 6.3.2). Meanwhile, reform options are discussed, e.g. to refinance the technology development part via a fund in order to lower the surcharge and to have a more equal burden sharing between different consumer groups (Matschoss und Töpfer 2015a, 2015b) as well as other models (Agora Energiewende 2017d).

8.6 Strategic role of electricity networks

8.6.1 Comments from German partner

Strategic role of electricity networks

The main problem with the network system in Japan seems to be its weak interconnections across the former monopoly areas. In addition it has inherited a two-frequency-system (50 and 60 Hz) posing an additional bottleneck (section 4.3.1.1). This is also mirrored in the market place at JEPX where markets are regularly split into different price zones along the previous monopoly areas in order to manage scarce interconnector capacities. Splitting between certain Islands as well as between the two frequency zones occur particularly often (section 3.1.1.2). On the one hand, this strong fragmentation hinders flexibility for e.g. integration of renewable energies. On the other hand it highlights the high potentials of regional integration despite being an island. Whereas Germany can increase its efficiency by increasing interconnector capacity with its neighbors, Japan may be able to do so by increasing transmission capacity *within* the country. Increasing network and interconnector capacity should have high priority in the basic energy plan.

Naturally, the two-frequency system (section 4.3.1.1) appears to make flexibility particularly difficult. However, as it appears, increasing converter capacity was mentioned as the cheaper option rather than switching to one of the two systems.

With regard to RES-capacities the current concept of “connectable amount” constitutes an important bottle neck for expanding RES-capacities (section 4.3.1.6). Since there is no dedicated priority grid access for RES-capacities, the first-come-first-serve-principle creates a bias towards the incumbents. Furthermore, the determination of connectable capacity only once per year results in time lags and appears to determine the growth path of new capacities, regardless of the height of the feed-in tariff. As mentioned above, the German experience shows that networks can usually absorb considerably more variable capacity than was previously thought. This, however, requires also changes in the energy markets (e.g. more short-term trade) and organizational changes on the level of the grid operator (different handling of networks). Taken together, the level of connectable amount should be determined according to the priority of VRE that is decided in the basic energy plan. This, in turn, should determine the necessary grid extension and not vice versa. Another aspect is the distribution between the technologies in order to use the complementary and lessen the need for networks and flexibility options, thereby lowering integration costs per kW installed as it is pointed out in section 8.2.3.2.

Further, as mentioned in the beginning, non-discriminatory market access and pricing of grid use are vital for the functioning of liberalization. There needs to be an independent authority to have oversight over the Transmission and distribution grid operators. It is therefore an open question whether the current institutional arrangement is able to achieve that (section 4.3.1.6).

Going beyond electricity – inclusion of heat, cold and synfuels

Another means to ease RES-integration and to increase efficiency is to increase the connectedness not just between regions but also between the sector, known as sector coupling. Using “excess” electricity, especially from VRE, for power-to-heat also in district heating and –cooling), power-to-gas etc. in a manner closer to the area of electricity production may be a means to lessen necessary network extensions (or bridge the time until extensions are in place). That is, the energy system as a whole needs to be re-optimized, not just the electricity part.

8.6.2 Reactions to comments

8.6.2.1 Reactions from Japanese partner

It is true that “connectable amount” have been forcing utilities to operate the network inefficiently and hinders the diffusion of renewable energies. Therefore, discussion is going on at the government committee in charge of the network. As a result of deliberation, the rule of connectable amount will be amended and “connect and manage” adopted in UK will be likely to be introduced.

We acknowledge the importance of sector coupling. After the direction of future generation mix is determined, sector coupling will a major theme.

8.7 Dependency in imports and specific resources

8.7.1 Comments from German partner

Renewable energies and import dependency

An energy transition strategy that builds on increasing RE-shares also raises the share of domestic energy thereby decreasing the dependency on energy imports. This reinforces the point made in section 8.2.2 that also other renewable potentials should be considered and developed. It also adds another dimension to the discussion on costs: When the reduction of import dependency is considered an additional benefit, it needs to be taken into account into the cost-benefit-analysis of these technologies.

How dependent is Japan on Nuclear?

Lastly, two points are striking: Despite Japan’s traditional reliance on nuclear energy the generation share was usually around 25% (the maximum share was 29% in 2000) but it was not in the range of e.g. 50% or more as one may expect. Furthermore, in 2015 peak demand (160 GW) is well below (i) total capacity (315 GW) and still well below non-nuclear dispatchable capacity (195 GW combustible and 50 GW hydro – the latter would require a deeper analysis of the shares of run of river, water reservoir/seasonal and pumped storage but Figure 7 shows high shares of pumped hydro). That is, the problems the Fukushima accident caused (again: just from an energy system point of view) like rolling blackouts in the first weeks in the TEPCO-Area seem to be related more to scarcities of transmission network and interconnector capacities rather than to scarcity of generation capacities per se. Naturally, the suddenness of the outage created an unprecedented challenge and Japan could not revert to the long-term built-up of renewable capacities (resulting, in turn, in an increase in emissions and import reliance). On the other hand, the necessary technologies for a renewables-based transition are now available if policy wishes to take the decision.

8.7.2 Reactions to comments

8.7.2.1 Reactions from Japanese partner

Energy policy in Japan has been formulated based on three E's (Economics, Environment, Energy Security) and S (safety). In light of recent declining costs of renewable energies, in particular VRE, renewable energies can meet the requirement for all elements comprising the energy policy in Japan. Yet, the cost of renewable energies is not necessarily comparable to other countries. For example, the PV cost is about two times higher than in Germany. The cost of module does not differ so much. But the soft costs do. The soft cost accounts for more than 50% in Japan. Reducing this cost is a mandate for developers (Gallagher 2017).

As correctly pointed out by the partner, an attribute as an indigenous energy should be taken into account as positive external economies of renewable energies.

9 Common conclusions and recommendations

9.1 Common conclusions

Both countries are at different stages of liberalization and at different stages of energy transition. Germany's liberalization has been implemented for a number of years. Meanwhile, Germany has also decided to phase out nuclear energy and has continuously built up renewable energies. Over time, VRE have turned out to be the lowest cost renewable energy sources. Germany has reached the point where VRE are gaining system relevance. This requires modifications to the energy systems technically as well as in terms of market design, requiring a second set of market design reforms after liberalization. Germany has developed a long-term framework for the transition.

Japan is still at an earlier stage of energy transition. It is also still in a process of market liberalization. Therefore, when modifying the system it may accommodate both – energy transition and liberalization – at once. Further, there is a broad menu of low-carbon options available today. However, Japan does not have a long-term plan yet. In particular, the future role of nuclear is yet unclear.

Both countries are committed to the Paris agreement. Since investments in the energy sector are typically long-term, any framework setting needs to translate the Paris agreement into the right investment signals in order to avoid stranded investments. Both countries still have high generation shares from fossil capacities and need to decarbonize their energy sectors. Both countries have to decrease the use of fossil fuels; in particular Germany has to decrease the use of lignite. Japan still has low shares of renewable energy sources. Both countries are committed to raising energy efficiency.

Increasing network capacity is beneficial for any kind of energy transition. Both countries could increase the efficiency of use of their generation capacities by increasing network and interconnector capacities: Germany may increase interconnections with its European neighbors and Japan may increase interconnections within the country. In particular, increasing network capacity gets of strategic importance with rising shares of VRE in order to raise flexibility. A balanced distribution among the VRE, however, lowers variability and the need for flexibility options for any given amount of VRE-capacity. Increasing network capacity also includes new functionalities like sector coupling (heat, mobility) and storage. Therefore, from an infrastructure perspective an energy transition goes beyond mere enhancement of electricity grids and also involves district heating and gas grids. That is, an energy-transition-related re-optimization includes the whole energy system going beyond the electricity sector.

The most controversial point between Japan and Germany is the role of nuclear energy. Japan has regarded nuclear power as a means to reduce import dependency. This has always been a key issue for an Island nation that is endowed with hardly any resources. Before the Fukushima accident, nuclear power was regarded as a source of clean and safe power. Now this is under re-consideration and therefore the basic energy plan has not yet defined its future role. The nuclear power industry has been also a strategic industry rather than mere energy industry for Japan. For many people and policy makers in Germany, on the other hand, the risks of this energy source are not acceptable and costs are not competitive either, which becomes particularly obvious in a liberalized market setting. In particular, costs of accidents and nuclear waste disposal appear to be potentially very large and their uncertainties are huge and therefore unacceptable from the German point of view.

A controversial issue on the use of renewable energy is the rising FIT surcharge: In Germany the rising FIT surcharge result mainly from (i) high FIT-rates to early installations (mainly PV) when the technology was immature (i.e. financing the learning curve), (ii) low prices on the wholesale market as the FIT-system finances the differential costs between revenues and the sum of all payments to installations and (iii) exceptions for energy-intensive industries from the FIT that need to be cross-subsidized by households and non-energy-intensive industries. Nevertheless, alternative finance mechanisms are currently discussed (e.g. via taxes, funds etc.) for various parts of the surcharge (learning curve investments, industry exemptions or the surcharge as a whole). Furthermore auctioning is currently been introduced. In Japan the surcharge has risen due to high growth rates at high FIT-rates since 2012 and partial exemptions for electricity-intensive industries from the surcharge. Auctioning is also being introduced.

For both countries, an energy transition based on renewable energies would also be beneficial in terms of reduced import dependency as renewable energies represent “domestic” energies. Therefore, this aspect should be taken into account when discussing the costs of renewable energies. It follows from that that both countries should make best use of their potentials for renewable energies and try to access potentials that have not been used so far.

Furthermore, apart from technicalities the energy transition based on VRE in Germany was always also driven by people who organized themselves in cooperatives and similar organizations. This was enabled by the FIT allowing for easy-to-handle business models and shielding them from the power of the regional monopolies. Beyond mere decentralization this has therefore been coined ‘collective effort’ (*Gemeinschaftswerk*) or ‘democratizing energy’ and shows that there was always a further dimension to the issue of energy transition.

9.2 Recommendations

- Both countries need to create a market design that translates the Paris agreement into their energy markets by setting incentives for the decarbonization of their energy systems. This, in turn, requires long-term guidance from the governments of both countries as the energy sectors involve long investment cycles and possibly associated sunk costs. The creation of this new market design partly results in different challenges for both countries though.

- A common challenge is the reduction of the use of fossil fuels: Despite the existence of its long-term plan, Germany needs to reduce the use of coal, in particular of lignite. Japan, too, needs to reduce the use of fossil fuels, in particular, if nuclear as an abatement option fails, Japan needs to reduce fossil fuel use by other measures. Both countries need to increase energy efficiency.
- Japan needs to establish a long-term plan. In particular, this plan needs to include clear guidance on the future role of nuclear energy in order to avoid (more) stranded investments. Japan also needs to increase its renewable energy share, in particular as most of those energy sources are also beneficial from an energy security point of view.
- Both countries need to make use of their renewable energy source endowments. Since there is a whole range of low-cost options available nowadays (incl. wind, PV and geothermal) both countries shall aim at a balanced distribution between technologies as this lowers integration costs.
- Reinforcement of the grid is of strategic importance for both countries and both countries do have the possibility to do so. Germany can further increase interconnections with its European neighbors. Japan needs to further increase interconnections within the country (between the former monopoly areas), i.e. of using the grid integration options that it has despite being an island country.
- Both countries need to set the framework for (more) sector coupling, i.e. for the inclusion of heat (and cold) and mobility. As a prerequisite, electricity grids need to be enhanced with new functionalities (smart grids) to enable the coordination between the sectors – technically and in terms of market incentives. That is, both countries need to carry the transition further and re-optimize the whole energy system including all infrastructures.
- Both countries should examine the current scheme to refinance the FIT-surcharge. New capacity additions are often low cost. That is, the rising surcharge is often due to old installations (i.e. due to technological learning) or due to exemptions to large industrial consumers. A number of ideas exist for alternative concepts.
- There is a necessity for further research on how to create sufficient incentives for the various flexibility options necessary to integrate variable renewable energies (VRE). There is more than one way to create sufficient incentives and implications may differ between Japan and Germany. Therefore, a thorough analysis is necessary of what incentives do the different market forms like an energy-only-market and various forms of capacity mechanisms create in the Japanese and German settings. Further research questions include their implications for efficiency, distribution and structural change towards a low-carbon economy.

- There is also necessity for research in instrument design for financing renewable energies. Even though there is a range of low cost technologies available, it is not always clear whether regional cost differences (i.e. between Japan and Germany) may be attributed to the circumstances or to differences in instrument design. Finding the regionally/nationally tailored instrument mix that is low cost, open to innovations without creating new lock-in effects is a research challenge that goes beyond the discussion of technology-neutral vs. technology-specific instruments.
- Further, there is a necessity for research on the integration of VRE and the integration cost as these are energy system specific.
- Furthermore, economic barriers to sector coupling need to be removed, leading to the research question of a new distribution of taxes and levies that accommodates various goals such as increasing flexibility (better transmissions of scarcity / surplus situation signals in the grid), emission reduction needs and distributional issues.
- Finally, another issue for research is the above-mentioned modification of a partly alternate refinanced FIT-system.

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Appendix A

The German Renewable Energies Act 2012 obliged generators to directly market their power production and shifted the remuneration mechanism to a floating market premium which compensates for differences between the levelized costs of energy (LCOE) which are approximated by the so-called “value applied” for each RES technology and the spot market revenues. The difference is not determined for every price and time step. Instead, the monthly average market value of every form of RES is determined ex post separately. The market value of wind energy for instance is defined as:

$$MW \frac{\sum_{t=1}^{n} p_{EPEX\ Spot,t} \cdot x_{Wind,t}}{\sum_{i=1}^{n} x_{Wind,t}}$$

With:

MW: (relative) market value of specific month

n: number of hours of specific month

$p_{EPEX\ Spot,t}$: average price of hourly contracts at EPEX Spot Day-ahead market in hour t

$x_{Wind,t}$: wind energy production in hour t (TSO extrapolation)

The “value applied” (corresponds to the LCOE) in turn are given by the amount administratively determined in the German Renewable Energies Act or set by tendering procedures (see sections 4.2.2.2.5 and 4.2.2.2.6). So the floating market premium is calculated as follows:

$$MP \ = VA - MW$$

With:

MP: market premium for the specific month

VA: “value applied”

MW: (relative) market value of specific month

The revenue a power plant operator resp. a direct marketer achieves for every hour consists of the market premium which is fixed for one month and the revenue that can be achieved at wholesale power markets, i.e. usually spot markets, for that hour:

$$RT_t \ = MP + Spot_t \approx VA$$

With:

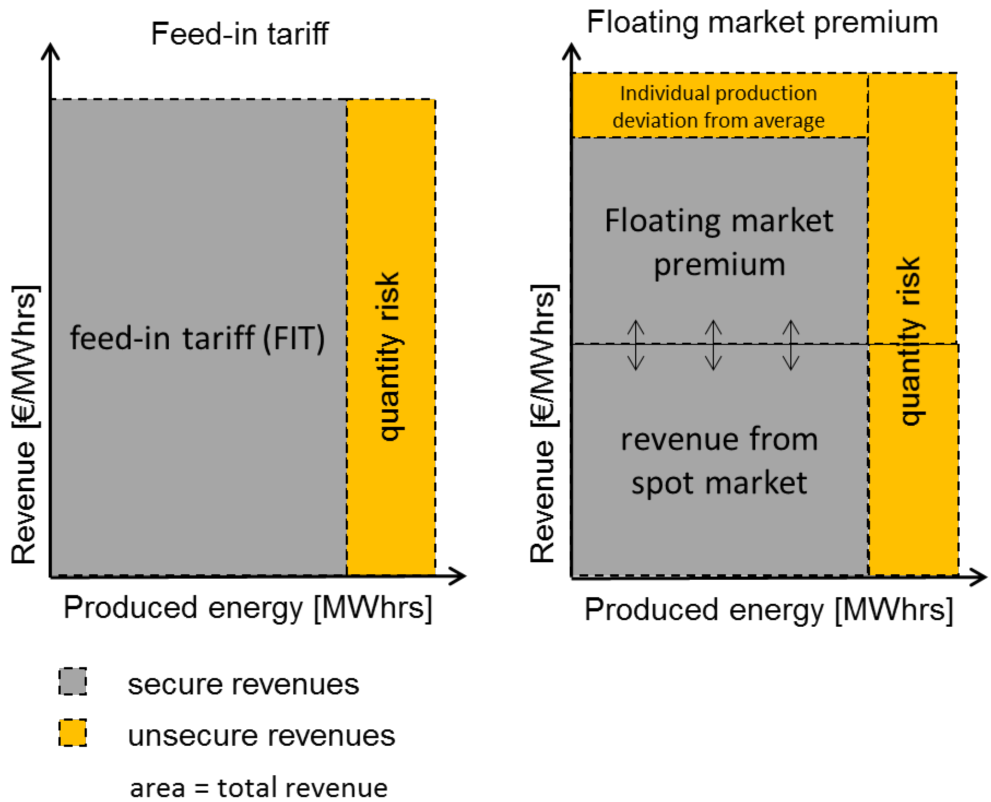
RT_t: total revenue in hour t

$Spot_t$: spot market price (revenue) in hour t

If the generation-characteristic of the plant considered for every time step equals the average of power plants of that RES source (in theory), the achieved revenue equals the "value applied" for that technology for every time step. Of course, this is a theoretical assumption. But on average, for most power plants the revenue that can be achieved more or less equals the value applied so that the LCOE are more or less compensated for.

Figure 56 compares the system of the floating market premium to the feed-in tariff: Whilst feed-in tariffs only place the quantity risk to RES power plant operators, a floating market premium shifts part of the market price risk from the society as a whole to RES power plant operators. From a microeconomic point of view, this in turn opens up a possibility for production resp. portfolio optimization (see paragraph "direct marketers").

Figure 56 Comparison of feed-in tariff and floating market premium



Source: IZES / own depiction

Appendix B

The market premium model incentivizes to reduce the power infeed if the absolute value of negative prices is high enough. This is due to the relationship between contribution margin and spot market price as can be described as follows:

$$CM_t = RT_t - OC = MP + Spot_t - OC$$

In order to earn a profit and to recover fixed costs the contribution margin must be greater than zero at any time:

$$CM_t > 0$$

i.e.

$$MP + Spot_t - OC > 0$$

Since operational costs as well as the market premium are fixed for the time step considered, the spot market price remains as only variable. Solving the inequality above for $Spot_t$ leads to the following expression:

$$Spot_t < -MP + OC$$

Because the operational costs of the variable RES considered are near zero, they can as well be neglected for a general understanding:

$$Spot_t < -MP$$

So the rational strategy is to curtail variable RES generation in cases the spot market price falls below the negative value of the market premium (plus operational costs). Furthermore, a regulation in the German Renewable Energies Act that was introduced in 2014 determines that no market premium is paid if the spot market price is negative six hours in a row (§ 51 subsection 1 EEG 2017). This affects the microeconomic rational of direct marketer.