MASTER's THESIS – RENEWABLE ENERGY MANAGEMENT

Cologne University of Applied Science - Institute for Technology and Resources Management in the Tropics and Subtropics

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DEVELOPMENT OF A PYTHON MODEL FOR ELECTRICITY RETAIL PRICES IN GERMANY UNDER PRESENT REGULATORY FRAMEWORK AND FUTURE EXPECTATIONS OF HIGH RE PENETRATIONS

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“*DEVELOPMENT OF A PYTHON MODEL FOR ELECTRICITY RETAIL PRICES IN GERMANY UNDER PRESENT REGULATORY FRAMEWORK AND FUTURE EXPECTATIONS OF HIGH RE PENETRATIONS*”

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ABSTRACT

This thesis presents the perspective and basis for modeling of retail electricity price components in Germany. Detailed Python models are developed to provide predictions for yearly development of average network charges, EEG, StromNEV-19 and KWK surcharges for the period 2015-2035. For network charges and EEG surcharge, scenario-B (2035) from NEP2015 has been chosen as the model scenario. For KWK surcharge, the 2025 KWK share target, set by KWKG-2016, has been chosen as the model scenario. Individual component model results are validated against available academic literature and institutional reports. Model results for EEG surcharge, indicate an increasing yearly EEG costs till 2024, after which the expiring EEG plants of past will unburden the related high costs and EEG surcharge will drop but still be around 99% of 2015 level in 2035. Model results for network charges indicate a consistently increasing yearly trend owing to high grid investments needed for reaching the target RE share of 57%. KWK model results also indicate a growing KWK surcharge until 2020 which then would remain stagnant at that level onwards. All model results are collected under three consumption categories, namely, households, privileged and nonprivileged industries. The final results indicate that the average German household will face an overall increase of around 3.37 Cents/kWh in retail electricity prices (excluding VAT) till 2028, after which the retail prices will drop a little due to dropping EEG surcharge. The similar but slightly reduced trend can be seen for nonprivileged industrial consumption. The increment effect, however, is only minute for privileged industrial consumption due to high exemptions in EEG & KWK surcharges and reduced individual network charges.

1 INTRODUCTION

Wuppertal Institute of Climate, Energy and Environment holds a strong research focus into German Energiewende and maintains several computer models relating to prediction of whole sale electricity prices and feed in from RE technologies. Furthermore, they have developed well researched future scenarios for RE development, policy directions etc. There was a need for in-house development of a model that can translate whole sale price predictions to retail price level with the help of existing model results and future scenarios. This master thesis has been executed in coordination with the institute to lay the ground work for a python model that would serve the above stated purpose.

This thesis is divided into six sections. This section provides introduction to German retail electricity sector and latest electricity retail price statistics. Sections 2,3 and 4 provide perspective, model description and model calculation results for the retail price components modelled in python. Perspective part provides overview of historical developments, evolving mechanisms and context with renewable energy growth. The part of model description states the adopted modelling approach for the respective price component from year 2015 to 2035. In the subsequent sub-sections, calculation results are presented along with validations from external literatures. Section-3 relates to EEG surcharge. Section-4 relates to network charges and associated additional surcharges while section-4 relates to KWK surcharge. Section-5 provides the collective model results segregated across three consumer classes. Section-6 relates the model concluded results to current social, political and technical affairs encircling electricity sector of Germany and Europe in general. A brief outlook on research gaps and possible future research opportunities linked to the model are also presented in section-6.

1.1 Electricity Retail Sector of Germany

Germany has a vertically unbundled market based electricity supply chain. There are many market participants on electricity retail side. The retail market enjoys a low concentration with Herfindahl-Hirschmaasd Index (HHI) well below 1000, which is generally considered as an indication of a competitive market (Bayer, 2015). In 2016, BNetz’s monitoring report (BNetzA, 2016a) surveyed around 1,238 retail suppliers to get an average estimate of electricity price components charged to various consumer classes. According to that report, around 54.8% of network areas had above 100 operating retail suppliers.

In Germany, small consumers, including households and small to medium businesses, are generally metered on non-interval basis. A two-part tariff structure is commonly used consisting of fixed base price and working price/kWh. Base price usually covers consumption independent costs of metering, billing, demand based part of grid charges per KW and retail supplier’s fixed costs. Working price contains all other energy dependent components.

Consumer class with yearly consumption above 100MWh generally employ interval metering (BNetzA, 2016a). Such consumer can have time of use tariff. The key differences in this regard is that the consumer on interval metering tariff can be charged the time-based electricity procurement costs and the time of consumer's load peak occurrence relative to system peak can significantly affect the peak charges (cents/KW) and consumer's eligibility to exemptions in overall network charges. Other tariff methodologies are also employed in Germany but are rare (BNetzA, 2016a).

For any consumer class, retail electricity price usually comprises of at least ten distinct components. Almost all components are not constant but vary depending on consumer class, supply area, eligible legal exemptions and time frame. They also differ with respect to nature of supply contract. Retail suppliers generally control less than one third portion of total retail electricity price which mainly comprise of energy procurement costs, delivery costs and profit margins. These costs are hereafter referred as 'supply costs'. Some components, mainly network charges, billing/metering costs and concession fees, are regionally dependent based on regulated costs of regional Transmission System Operators (TSOs) & Distribution System Operators (DSOs), municipality taxation policies and meter operator costs. Other components comprising of surcharges and federal levies are calculated as per several legislative instruments and uniformly applied at the state level. Table 1.1 indicates the various retail electricity price components and their major controlling factors.

Table 1.1 Electricity retail price components and major control factors

Sr. No	Price component	Major Controlling Factors
1	Network Charges	Regionally based TSO & DSO regulated costs, Municipality based taxes
2	Concession Fees	
3	Billing, Metering and Metering Operations	
4	EEG Surcharge	State controlled mechanism of calculation at state level
5	KWKG Surcharge	
6	19-StromNEV Surcharge	
7	Offshore Liability Surcharge	
8	Interruptible Loads Surcharge	
9	Electricity Duty	
10	VAT	
11	Electricity Procurement Cost	Retail Supplier controlled buisness operations
12	Supply Costs	
13	Supplier Margin	

1.2 Latest Electricity Price Statistics

To estimate the average retail electricity prices and components per kWh, BNetzA executes a yearly survey of retail supply industry where the retail suppliers are required to provide all types of retail costs on per kWh basis representing average of different tariff products based on regions, consumer types and contract types. The retail components are generally inquired against multiple consumer classes. This classification is mainly based on gross yearly consumption along with assumptions for peak load, full load hours and grid voltage level to which the consumer is connected. (BNetzA, 2016a) provided these statistical estimates using two non-household consumer classes and four household consumer classes. Non-household classes consisted of customers that consume annually above 24GWh (industry) and 50MWh (big businesses). Household classes consisted of customers having annual consumptions in ranges covering from below 1,000kWh to above till 10,000kWh.

(BNetzA, 2016a) states that at industry level, specifically for 24GWh class (C-24GWh), the retail tariffs are frequently tailor made to suit the respective consumer needs. Price portion controlled by the retail supplier vary significantly based on contract nature which may cover full scale retail services or mere the service of balance responsibility at wholesale market level. Often the retail prices are indexed with wholesale price. Many times, the retail company is an affiliation of the consuming enterprise. Another characteristic of this consumption class is that many industries are eligible to wide range of exemptions on multiple regulated price components.

Consumers with annual consumption at 50MWh or above (C-50MWh) usually represent medium to large business entities. In this category, (BNetzA, 2016a) states that the consumers are usually non-interval metered and presumably a standard load profile is frequently used. Contractual arrangements play less significant part here and standard rates are easier to estimate.

At the household level many different tariffs exist, although not very divergent in cents per component, owing to two main parameters; annual consumption and supply contract type. As stated earlier, (BNetzA, 2016a) surveyed for four different consumption classes. It also categorized the supply contracts in three distinct types and explained the coverage nature of each type. The types of contracts are:

1. Default supply contract
2. Special supply contract with default supplier
3. Contract with other supplier who is not the local default supplier

Consumers usually switch from default contracts to special contracts or contracts with other non-local suppliers for reasons such as lower tariffs and security features like price stability guarantee etc. Analyzing the data available in (BNetzA, 2016a), it can be easily observed that special contracts or contracts with non-local suppliers make lower tariffs by reducing supply costs thus overcompensating slight increases in costs of billing/metering and network charges. It can also be observed that electricity tariffs decrease from low to high consumption. The prime decrease occurs in tariff components such as supply costs, network charges and billing/metering. Figure 1.1 shows the average values of several price components for all four household consumer classes as of 1st April-2016. Only the components that vary across classes are displayed. It can be observed that total price decreases to 66.5% as we go from lowest consumption class to highest.

Table 1.2 depicts the retail price components, as of 1st April-2016, for the two stated non-household classes and a household class with consumption range of 2,500kWh – 5,000kWh. Values listed for 24GWh class are based on assumption of zero exemptions granted. Values listed for household class are volume weighted averages across all three supply contract types.

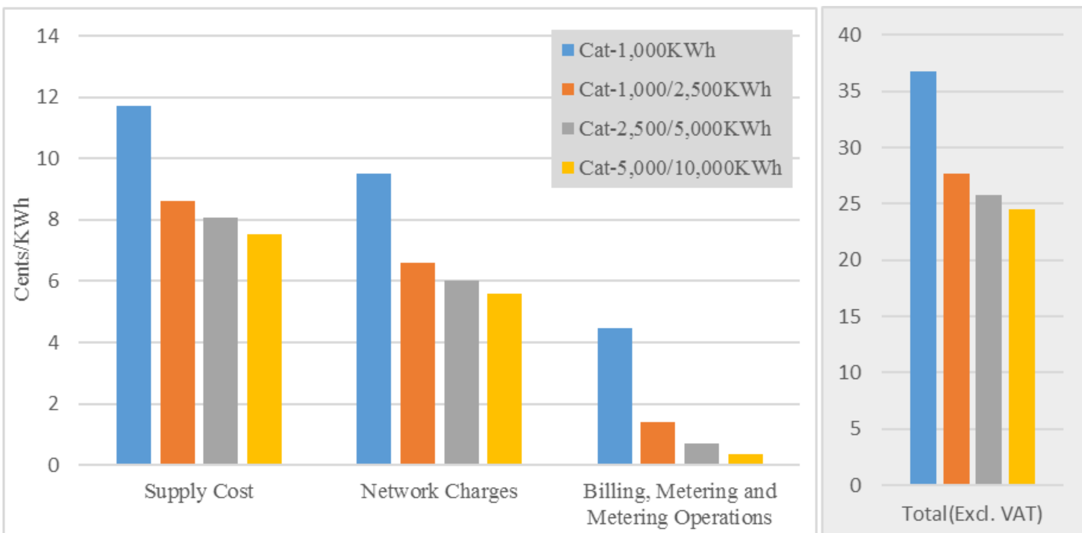

Figure 1.1 Variable price components for default supply contracts across four household consumer classes on 1st April-2016 [Source: (BNetzA, 2016a)]

The Figure 1.2 gives a comparative status of those price components across three consumer classes that are significant in value and vary across the classes. It can be observed that the total retail electricity price falls as we go from household class to industry class (around 56.6%). The prime decrease occurs in network charges, concession fees and supply costs. Network charges become low because industries often have asymmetric peak demand and are connected to high voltage networks which avoids downstream network costs. Concession fees are also less at transmission grid level owing to less territorial spread of the grid network. Supply costs decrease mainly due to bulk purchasing, consuming more during off peak periods and flexible contracts.

Table 1.2 Average retail price components across three consumer classes on 1st April-2016 [Source: (BNetzA, 2016a)]

Price Component	C-2500/5000kWh	C-50MWh	C-24GWh
Network Charges	6.11	5.5	2.03
Concession Fees	1.65	0.35	0.03
Billing, Metering and Metering Operations	0.68	0.93	0.11
EEG Surcharge	6.35	6.35	6.35
KWKG Surcharge	0.45	0.44	0.06
19-StromNEV Surcharge	0.38	0.38	0.06
Offshore Liability Surcharge	0.04	0.04	0.03
Electricity Duty	2.05	2.05	2.05
Supply Costs	7.35	5.15	3.48
Total(Excl. VAT)	25.06	21.19	14.2

In addition to the important variations in price components across consumer classes as shown in Figure 1.2, exemptions in certain price components applicable to energy intense industries can significantly change the overall electricity price for such consumers. For full eligibility cases, electricity duty and concession fees are fully exempted, while EEG surcharge, network charge and other surcharges can reduce by 92%, 80% and 44% respectively (BNetzA, 2016a).

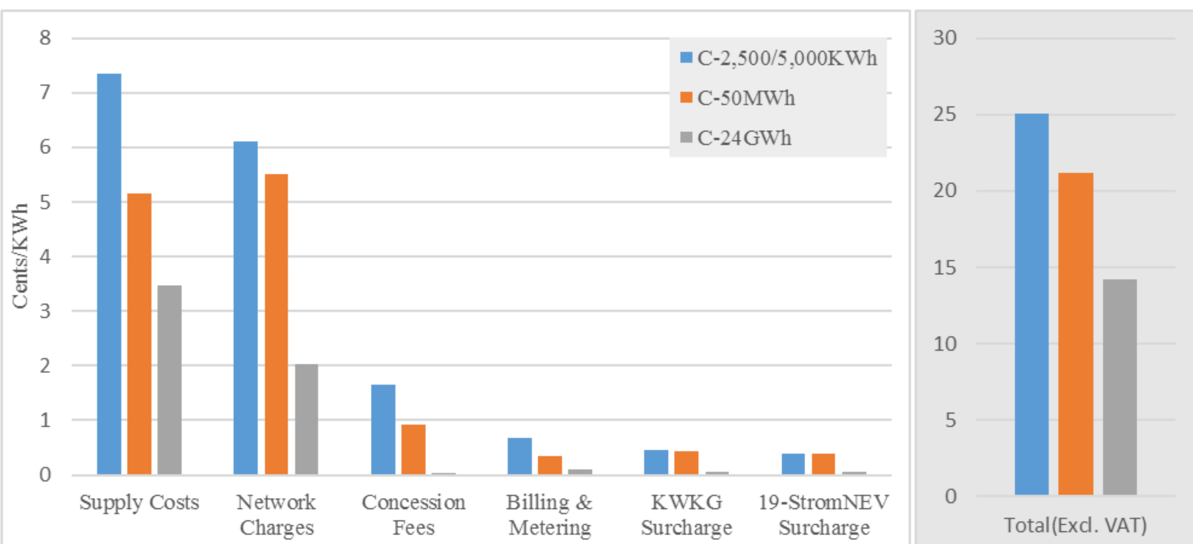

Figure 1.2 Significant electricity price components across three consumer classes on 1st April-2016 [Source: (BNetzA, 2016a)]

2 EEG-SURCHARGE

2.1 Perspective

EEG surcharge or EEG-Umlage was first introduced as a component of retail electricity price in Germany in 2000, consequent to coming in force of Renewable Energy Sources (RES) Act or Erneuerbare Energien Gesetz (EEG) in 2000. (Gründinger, 2017) gave a comprehensive overview and context about historical EEG developments in Germany, often citing other references to explain the changes in EEG with time. Features of each EEG Act relevant to thesis scope are briefly highlighted in following text. The said source is consulted and referred as needed to understand the special features of each EEG version.

2.1.1 Electricity Feed-In Act

Before 2000, there was no EEG surcharge, however, the RE support scheme was still present under Electricity Feed-In Act (STrEG) of 1991. The law came in context to obstructing traditional grid companies and insufficient tariffs granted to RE plants based on averted costs (Gründinger, 2017). The author states that for the first time, STrEG-1991 enforced three pioneer market regulations mainly compulsory connection, priority feed in and guaranteed payments to RE power plants for 20 years. As per STrEG-1991, the payments were coupled with retail price of electricity, primarily setting the remunerations of wind and solar plants as at least 90% and other RE sources as 80% of average retail price of the year of commissioning. Compensation scheme required the local grid company to pay for the RE feed and recover it from its consumers. (Gründinger, 2017) states that STrEG-1991 brought a small but steady RE growth and laid the basis of several institutional structures. However, the remunerations under STrEG-1991 were still insufficient to cover actual costs and too volatile to ensure investment security. Additionally, the compensation scheme caused regionally unequal distribution of costs among grid companies even after a later enforced 5% cap which limited the maximum RE feed in obligations for grid companies.

2.1.2 EEG-2000

Extending the above stated three pioneer market regulations, EEG-2000 brought along some fundamental changes in tariff structures with strong focus on covering costs of operation of RE plants. Some of the highlighted changes were:

1. An absolute feed in tariff differentiated across technologies, sizes and yields. Technology categories eligible for compensation were solar, onshore and offshore wind, biomass, geothermal and gas power plants using mine, sewage or landfill gas. Tariffs for biomass, geothermal and gas plants were linked to effective rather than nominal capacity.

2. An annual digression scheme that would decrease allowed feed in rates with time to incentivize cost reducing innovations.

3. A country level equal distribution of EEG costs through a mechanism whereby regional grid companies would pay compensations to RE plant operators and equalize their costs among each other which would ultimately be recovered through EEG surcharge from consumers.

4. A 51cents/kWh tariff for solar installations and supplementing low interest loan scheme, while putting a maximum solar deployment cap of 350MW and feed in eligibility limit of up to 100KW per installation. These limitations were removed later in 2003 in an amendment, where by tariff was differentiated w.r.t size and type of systems i.e. tariff for freestanding and rooftop installations and a bonus for building facade based solar installations.

5. Tariff for wind was in two steps: initial high tariff and lower base tariff. Default period of initial tariff for onshore and offshore plants were 5 years and 9 years respectively. To encourage installations in low yielding onshore areas, provisions for extension of initial tariff period were added linked with the gap of plant yield with a reference yield.

6. An amendment in 2003 allowed a special equalization scheme whereby energy intense industries with consumption above 100GWh/annum were allowed to pay reduced EEG surcharge of 0.05cents/kWh in concern to their declining competitiveness in global markets, however under several eligibility conditions.

EEG-2000 started an unprecedented growth in RE deployment and the overall share rose from 6.2% in 2000 to 9.3% in 2004, although the original EEG target was doubling the share till 2010 (Gründinger, 2017).

2.1.3 EEG-2004

After the founding structure laid down by EEG-2000, the revised version extended the previous provisions with increased tariff differentiations with respect to plant sizes and increased conditions. Some new additions that are relevant to modeling of EEG costs are stated below:

1. Wind plants that replaced previous installations or expiring stock within same municipalities, now called ‘repowering’, were allowed higher extension periods in initial tariff then allowed for normal onshore wind plants that lagged the reference yield stated above. Offshore plants also enjoyed such extensions where it was based on distance from shore. Default initial tariff period for offshore plants was also revised to 12 years.

2. New bonus system was introduced for all biomass plants that consisted of

    a. *Fuel bonus differentiated with respect to plant size and fuel type to encourage use of crop residues and special energy crops over the then status quo old wood and cheaper organic waste* (Gründinger, 2017). *Since, biomass plants can usually operate on multiple fuel type, the individual fuel bonus was applied only to portion of generation resulted from that specific fuel consumption.*

    b. *Cogeneration bonus of 2cents/kWh for production amount in combined heat and power mode.*

    c. *Technology bonus of 2 cents/kWh for innovative technologies like fuel cells, organic Rankine cycle etc.*

3. Funding period for small hydropower plants up to 5MW was limited to 30 years. For bigger plants till 150MW, eligibility of support was only allowed for any increased capacity because of modernization for 15 years of period and differentiated with respect to increased capacity classes.

4. Plants generating electricity using pipeline natural gas and replacing the same at some other grid point were included under EEG gas plant tariff schemes. There were further bonuses if the replaced natural gas was pre-processed or the generation plants are based on innovative technologies like Rankine cycle, fuel cells etc.

2.1.4 EEG-2009

By 2009, RE growth reached 16.3% of total generation and EEG costs more than doubled from 0.54 to 1.33cents/kWh (as per reference stated in (Gründinger, 2017)). These developments brought the focus of EEG revision to challenges of cost efficiency and grid integration. Some highlighted aspects of EEG-2009 were:

1. Solar tariffs were reduced and digression rates were tightened and linked to yearly growth corridors, all in context to falling PV costs, rapid solar boom and high operator profits. A unique regulation was added that gave fixed 25.01 cents/kWh to solar plant operators for self-consumed electricity. This clause incentivized self-consumption until reaching of socket grid parity before next revision period of RES act in 2012, after which it was discontinued. Although it was a step toward futuristic self-reliant energy systems with less grid burden, some bodies strongly opposed because of negative effects of lesser grid cost recoveries, tax collection and disturbance in load profile planning (Gründinger, 2017).

2. Wind onshore tariff was slightly increased in context to rising raw material costs but a gigantic leap from 4 to 13 cents/kWh was taken for offshore wind along with bonus of

2 cents if the plant came before 1st January-2016. A system services bonus of 0.5 cents/kWh was allowed for onshore wind plants coming before 2015. It was meant for those plants that could maintain frequencies, reestablish supplies etc. Repowering onshore wind plants were give same amount bonus as well.

3. Hydropower tariffs were significantly increased but the remuneration period was shortened from 30 to 20 years.

4. Geothermal plants were allowed for cogeneration bonus and bonus for using petro-thermal technology.

5. An option for direct marketing was introduced where the plant owners could monthly inform the grid operators if they wanted to get feed in tariffs or do direct marketing. However, there was no incentive given for direct marketing.

6. Grid operators were allowed RE curtailment for better grid management accompanied with equivalent financial compensation for the losses.

(Gründinger, 2017) states that by 2009 - 2010, global solar prices had fallen rapidly and Germany was experiencing a solar boom and there were high profit margins enjoyed by solar producers. The resulting burden of EEG costs on consumers was also rising. At the same time, German solar industry had been facing financial troubles as the imported PV panels were outcompeting even the biggest of European solar panel manufacturers. In context to counter pulling concerns of avoiding huge EEG related costs and promoting solar industry to save jobs, PV act, 2010 came into force. It decreased the solar tariffs, however, enhanced the incentive for self-consumption, therefore the relief on EEG costs were not significant.

2.1.5 EEG-2012

This revision of EEG act came at a time when several important happenings were changing the energy course altogether. Fukushima accident of 2011 had made German government to reverse its nuclear power prolonging plans. Solar boom led to a quite significant rise in EEG costs where the situation came to a point that solar energy accounted around 56% of EEG costs but a mere 20% share in total EEG supply. Merit order effect, now much increased due to solar expansion, squeezed the profit margins of conventional generators and endangered the economic viability of gas power plants which depended on peak load times to earn revenues. EEG-2012 enhanced cost efficiency features and reduced complexity by embedding several bonuses to base rates. Some highlighted provisions as per (Gründinger, 2017) were:

1. For accelerated growth of offshore wind power plants, a provision of increased initial tariff for only 8 instead of the default 12 years was introduced. Any plant operator could claim it from gird operator before plant commissioning.

2. Biomass bonuses were reduced in count and proportional remuneration was allowed for mixed fuel use. Conditions for eligibility of compensation were put that required a mandatory cogeneration or slurry use or direct marketing.

3. Consumers who used grid electricity for storage to be later fed back to grid again, were exempted for EEG surcharge. Industrial consumers who consumed energy purchased via grid produced from own generating plant situated in spatial proximity were also exempted from EEG surcharge.

4. For first time, a cost coverage mechanism was provided for direct marketing via market premium and management premium. Market premium was set as the difference between eligible EEG remuneration and average spot market price for corresponding month. Management premium was a top up given to compensate administrative costs of marketing and to cover market risk factor. In addition, direct selling biogas plants were given flexibility premium for ten years to be applied only to additional capacity offered for executing demand oriented operation. In this regard, additional capacity was required to be at least 0.2 times and considered only up to 0.5 times of the declared additional installed capacity. Flexibility premium was an incentive to increase demand flexibility of biomass plants through biogas storage development (Gründinger, 2017).

5. As an incentive to consider grid situation at the plant installation location, it was provisioned to compensate RE plants till 95% monthly losses owing to RE curtailment.

6. Solar tariffs were already reduced in the act but in context to rampant solar boom and EEG costs, an amendment act came to force which apart from further reductions and monthly digressions, also changed some fundamental structure for payment. Size classification was revised. Fixed entitlement of self-consumption was removed as the grid parity was already achieved. For market integration, solar plants from 10 to 100KW were allowed EEG remuneration only till 90% of annual generation. Moreover, an absolute cap of 52GW was set above which no further solar capacity was to be remunerated.

2.1.6 EEG-2014

Revision of EEG-2014, came into force on 1st Jully-2014, brought some fundamental changes to RE support framework. Apart from regular decrease in allowed compensation rates, digression rates for biomass, onshore and offshore wind technologies were linked to yearly expansion targets as was done previously for solar technology. Some highlighted changes were:

1. In contrast to previous default feed in support, direct marketing was set obligatory for all plants. Direct marking would enable plants to get market premium, which was in

fact the difference between average spot price and the fixed remunerations eligible to plants. Previously introduced management premium was merged into fixed remunerations. Small plants, without direct marketing, could enjoy fixed remunerations with little reductions on basis that no management costs were need for direct marketing. Other plants, in case of no direct selling, could also enjoy fixed remunerations but at 20% less rate. Therefore, there was a clear incentive to sell directly into the market and other option could be used for exceptional cases like insolvency etc. (Geipel, 2014).

2. EEG act 2014 indicated that from 2017 onwards EEG remunerations would be decided based on competition through a tendering mechanism. Furthermore, it provisioned the mechanism of tendering for determining remunerations for freestanding PV plants which would also serve a learning experience in future.

3. Self-suppliers that consumed electricity from own production without grid usage were subjected to percentage of EEG surcharge differentiated with respect to date and type of power plant. This provision was not applicable in several situations such as the self-supplier is off grid, or generator existed before new EEG regime or generator is below 10KW etc.

2.1.7 EEG-2017

As indicated in previous version of RES act, this revision extended the auctioning methodology onto biomass, onshore & offshore wind and all solar technologies. Some highlighted features, as per (BMWi, 2016a), are:

1. Fixed gross capacities, preset by law, will be auctioned every year for solar, wind and biomass plants. Through auctions, fixed remunerations for above 750KW solar and wind plants will be determined. For biomass, the limit will be above 150KW. Rest of the plants will continue with remunerations prefixed by law as usual. The targeted yearly RE capacity under auctions will make around 80% of total annual capacities expected to be installed. All plants will continue with default market premium model as incorporated previously with minor changes.

2. For geothermal, gas and hydropower technologies, there will be no auctioning schemes because of too little expected capacity expansion to suit competition. Therefore, there are no annual capacity caps as well (Agora, 2016).

3. Grid status is strongly integrated with support mechanism. For example, in grid bottleneck areas, onshore wind newbuild will be restricted to 58% of average newbuild between 2013 and 2015. Serval expansion limits differentiated on yearly and regional basis are introduced for controlling and steering offshore wind expansion.

4. Existing biomass installations will be allowed for an additional follow up 10 years funding under auctions provided they fulfil the requirements of flexible and demand oriented generation capabilities.

2.1.8 EEG surcharge exemptions

After the introduction of special equalization scheme, mentioned in 2.1.2, the scheme has been amended several times. As per latest EEG-2017, following reductions are allowed in payable EEG surcharges:

1. For two types of industries listed in annexure-4 of EEG-2017, reductions of EEG surcharge to either 15% or 20% is allowed in several cases. For eligibility, industry's electricity cost intensity must be at least 14% or 15% for respective types. In all these cases, reductions apply above one GWh consumption while reduced surcharge must not be lower than 0.1 Cents/kWh with exception that few industries can get as low as 0.05 Cents/kWh. Electricity cost intensity is defined as the ratio of means of electricity cost and gross value added for last three years.

2. For railway consumers which consume over 2GWh, get 80% surcharge reductions on all consumption.

2.1.9 Historical development of EEG surcharge

Figure 2.1 and Figure 2.2 show the yearly installed EEG capacities and energy production from 2003 till 2015. During this period, the overall installed capacity and energy arose more than 5 times. A particularly rapid increase in solar capacity started from 2009.

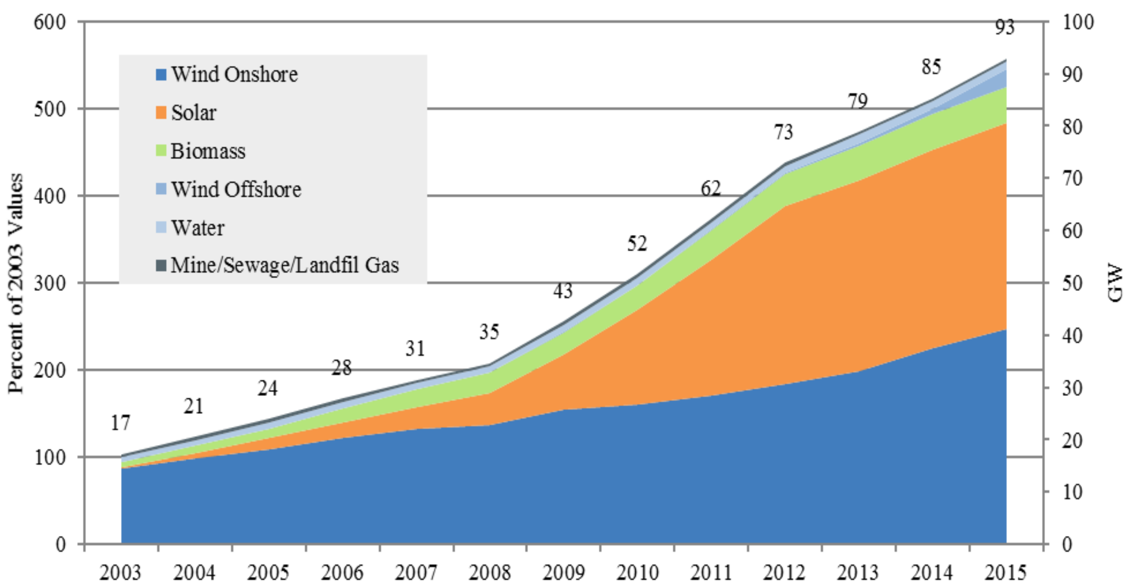

Figure 2.1 Yearly installed capacities under EEG support [Source: (BNetzA, 2016b)]

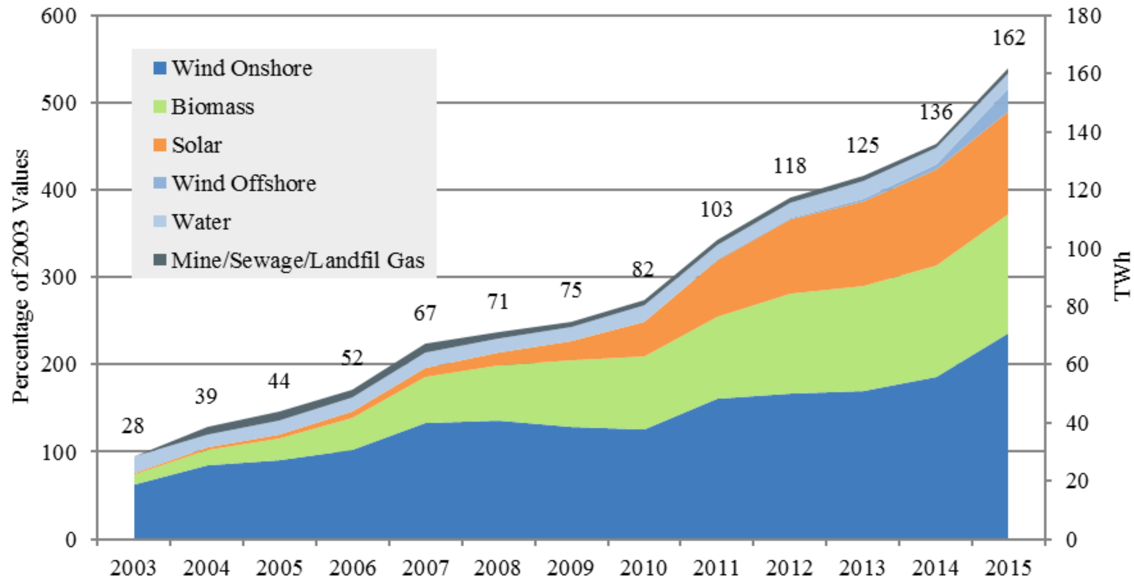

Figure 2.2 Yearly electricity generation under EEG support [Source: (BNetzA, 2016b)]

Figure 2.3 shows the yearly EEG costs per technology from year 2006 to 2015. During this period, the overall costs increased more than 3.5 times. It can be observed that the proportional share of solar costs in overall costs is much higher then as in energy generation.

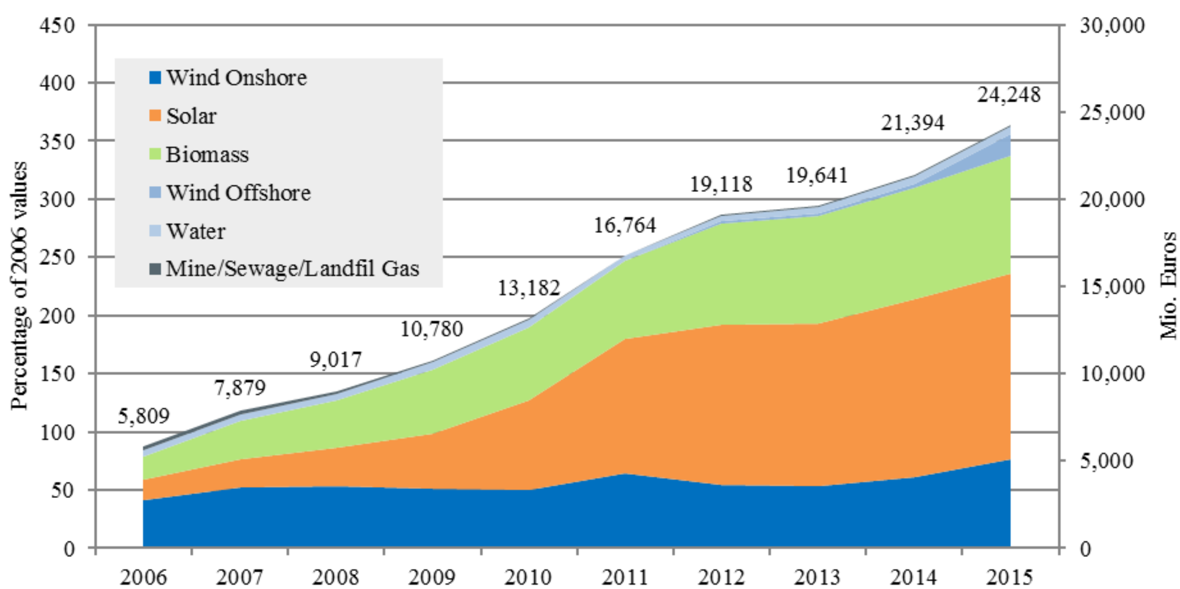

Figure 2.3 Yearly total EEG costs per technology [Source: (BNetzA, 2016b)]

2.2 Model Description

As per exemptions mentioned in section 2.1.8, the developed model determines the base EEG surcharge for unprivileged consumers and privileged EEG surcharges for 15/20% categories for a target year by following relations:

$$EEG_{baseSurcharge} = \frac{C_{DF-EEG} \times f_{cost}}{Con \times f_{unprv}} \quad \textbf{(1)}$$

$$\boldsymbol{EEG_{15\%Surcharge} = Max(\frac{C_{DF-EEG} \times 0.15}{Con}, 0.1)} \quad \textbf{(2)}$$

$$\boldsymbol{EEG_{20\%Surcharge} = Max(\frac{C_{DF-EEG} \times 0.20}{Con}, 0.1)} \quad \textbf{(3)}$$

Where:

C_{DF-EEG} = Total EEG difference costs

Con= Consumption in target year (assumed same for all years as of 2015)

f_{cost}= Factor to determine amount of C_{DF-EEG} left after excluding revenues from privileged consumers

f_{unprv}=Factor to determine amount of Con left after excluding privileged consumption and including equivalent portion of self-consumption subject to full base surcharge

(f_{cost} and f_{unprv} are determined as 0.993 and 0.703 using 2017 prognose (TSOs, 2016a) while *Con is set to 488TWh as of 2015. All parameters are assumed non-variable for calculations of future years)*

Yearly EEG difference costs are modelled by following relation:

$$C_{DF-EEG} = C_{EEG} - R_{market} - R_{Avoided-NC} + RC_{others} \quad \textbf{(4)}$$

Where:

C_{EEG} =Revenues generated by RE plant owners with remunerations defined by applicable EEG Acts.

R_{market}= Total revenue generated by sale of EEG generation in wholesale market

$R_{Avoided-NC}$= Total avoided network costs for energy generated by the decentralized EEG generators as described in 3.1.4. This amount is not paid by DSOs to RE plant owners but to TSOs.

RC_{others}= Other components consist of account balance from previous year's EEG account and an additional 6% liquidity reserve costs which is needed by TSOs for paying EEG remunerations.

Based on data in (BMWi, 2016b) for years 2015, 2016 and 2017 it is observed that previous year's account balance and liquidity costs have a canceling effect. Since, balance account is not modelled, RC_{others} is assumed to be zero. $R_{Avoided-NC}$ depends on the upstream voltage network rates and the energy produced by EEG plants. Due to model limitations, no data is available on upstream network costs. Further, no big change is anticipated in $R_{Avoided-NC}$ as per model results available in (Oeko-Institut, 2016). Therefore, based on stated insignificance, $R_{Avoided-NC}$ is not modeled but locked at the level as of 2015 using data from (BMWi, 2016b).

For calculation of C_{EEG} and R_{market} detailed modeling is carried out. A database of EEG power plants installed in Germany till 2015, originally available from (Energymap, 2017), updated by Wuppertal Institute is used. Data base provides information about applicable technologies, sub categories as per EEG for individual technologies and regional locations in terms of NUTS3 codes. In addition, hourly power curves for all technologies, developed by Wuppertal institute have been used. For Wind and Solar, these power curves are available for several regional coordinates based on regional weather data taken from Merra-NASA (*Merra2 Dataset*). A separate data table that links Nuts3 locations with ids as per Merra data was also used. An exception was hit with wind offshore plants which needed special regional description which was not possible under NUTS3 ids. All such offshore plants were allocated applicable ids of Merra data based on a separate data set provided by the institute and specific park characteristics to which the plants belonged. C_{EEG} and R_{market} for a target year are determined by following equations:

$$C_{EEG} = \sum_{i}\sum_{j}\left(\sum_{yr}\overline{Cap}_{ijyr}\times[(1-\overline{MF}_{P-NM})\times\bar{T}_{P-NM}+\overline{MF}_{P-NM}\times\bar{T}_{P-M}+KF\times\bar{I}_{P-KWK}]\times\overline{CE}_{P-fctr}\right)\times\sum_{hr}\overline{PC}_{ijhr} \quad \textbf{(5)}$$

$$R_{market} = \sum_{i}\sum_{j}\sum_{year}\sum_{hour}\overline{Cap}_{ijyear}\times\overline{PC}_{ijhour}\times\overline{WSP}_{hour} \quad \textbf{(6)}$$

Where:

i: technologies [Wind onshore, Wind offshore, Solar, Geothermal, Biomass, Gas, Hydro]

j: Respective id of Merra data yr: years from 1950 to target year hr: hours in a year

$\overline{Cap}_{ijyear}$ = *Vector with all plant capacities of i-technology, j-region and eligible for EEG support*

$\overline{MF}_{P-NM}$ = *Vector containing plant marketing factors*

$\bar{T}_{P-NM}$ = *Vector containing applicable plant tariffs to be paid for non-direct marketed electricity*

$\bar{T}_{P-M}$ = *Vector containing applicable plant tariffs to be paid for direct marketed electricity*

$\bar{I}_{P-KWK}$ = *Vector containing applicable increments for cogeneration based electricity (only biomass)*

KF= Factor to exclude non-cogeneration related plant capacity (only biomass)

$\overline{CE}_{P-fctr}$= *Vector with factors to decrease plant energy yield, commissioning or expiring in target year*

$\overline{PC}_{ijhour}$= *Vector containing hourly capacity factors for i-technology and j-location*

$\overline{WSP}_{hour}$= *Vector containing hourly whole sale price of electricity*

--All vectors with subscript-P have parameters that correspond to plant capacities available in vector $\overline{Cap}_{ijyear}$ *in same serial order*

--Python model can take as input the vectors of $\overline{PC}_{ijhour}$ *and* $\overline{WSP}_{hour}$ *based on years 2015, 2020, 2025, 2030 and 2035. Yearly calculations are executed using respective vector from nearest year*

2.2.1 Development of plant tariffs

As it is described in section 2.1, ever evolving EEG mechanisms gave diverse number of tariff schemes to EEG plants. The biggest challenge to work with plant data base was therefore, to determine tariff applicable to the individual power plants. Many entries in the plant data base came along with multiple EEG-keys. An EEG-key provides information to unique tariff level applicable to certain portion of electricity, certain technology and/or sub-category, EEG regime and bonus/non-bonus type. All such data was available as excel file from (Netztransparenz, 2016), which contained around 4300 unique EEG-keys. Except wind tariffs, all technologies have tariff levels differentiated against capacity portions. The average default tariff per kWh is therefore determined. Following example gives a simplistic understanding of calculation of average default plant tariff.

A solar plant installed on a building roof with capacity of 40KW in 2004

Applicable tariffs:
Tariff-1=T1=57.4 cents/kWh for 0-30KW with EEG-key=SoK111------04
Tariff-2=T2=54.6 cents/kWh for 30-100KW with EEG-key=SoK112------04

Calculations:

Share-1 of installed capacity in 0-30KW=S1=$\frac{\mathbf{30}}{\mathbf{40}}$*=0.75*

Share-2 of installed capacity in 30-100KW=S2=$\frac{\mathbf{10}}{\mathbf{40}} = \mathbf{0.25}$

Average Default Tariff in Cents/kWh= $\boldsymbol{S1 \times T1 + S2 \times T2 = 56.70}$

In above example, installed capacity is used for solar case. However, for non-solar cases, effective capacity must be used.

Python program was developed to determine average default tariff for each plant in the plant data base. Effective capacity is determined by dividing generation of 2015 (available with data base) by 8760 hours. Since, generation data for all plants was not available, capacity factors of applicable technology for year 2015 available from (BNetzA, 2016b) were used. By essence of above stated methodology, the higher is the plant capacity, lower is the plant tariff. Figure 2.4 to Figure 2.10 show the results of the default tariff calculation model along with brief highlights of each illustration. Figures have limited horizontal axis (years) range and zoomed vertical axes to allow better visibility.

For solar plants installed in years 2007 and 2008, two divisions between free standing and building solar plants can be clearly observed with former having lower tariff and no capacity dependence. Building solar plants show declining tariffs with increasing capacities. Subsequent years show complex interplay of increased digression rates mentioned in 2.1.5.

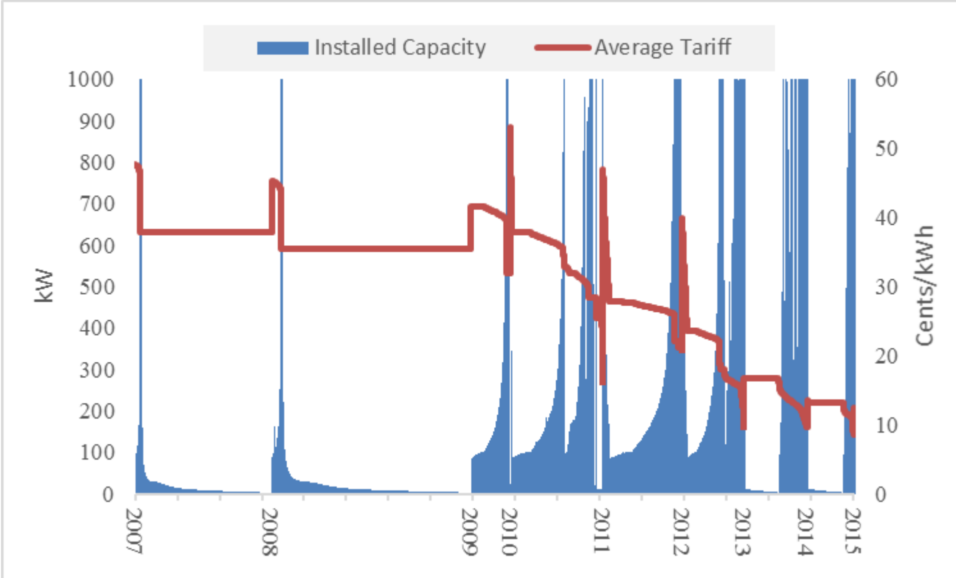

Figure 2.4 Solar plant tariffs (right) and installed capacities (left) ordered in ascending order of installation years and descending tariffs (zoomed vertical axis)

For biomass plants, the results appear more complex due to interplay of several bonuses mentioned in 2.1.3. However, in each installation year, a clear division can be observed. The division is due to a fact that many biomass plants, available in data base, provided no EEG-keys and basic tariff was allocated to these plants. Other biomass plants mostly contained keys corresponding to certain bonuses and got higher tariffs. Average default tariff for biomass plants with multiple bonus keys was determined using equal weightage to each bonus.

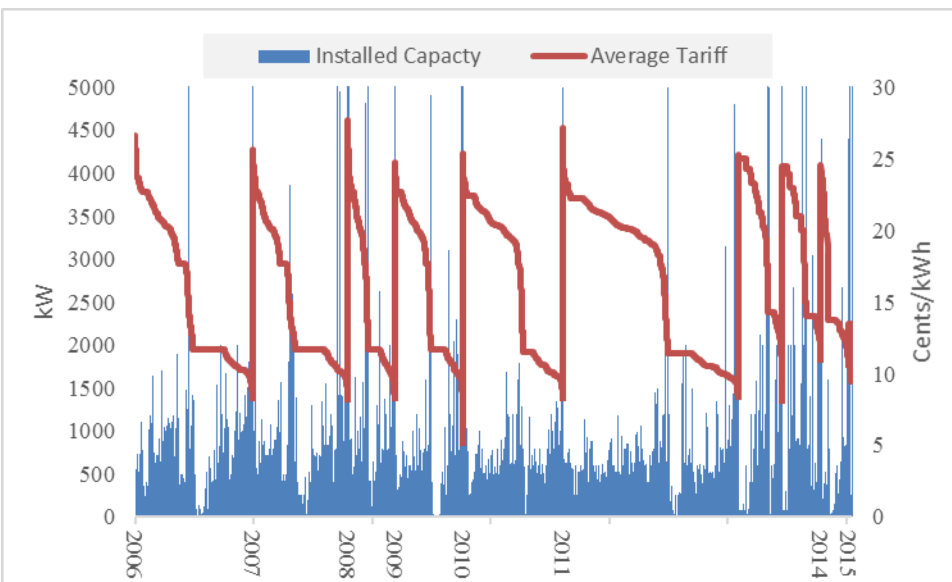

Figure 2.5 Biomass plant tariffs (right) and installed capacities (left) ordered in ascending order of installation years and descending tariffs (zoomed vertical axis)

For gas plants, installed in years before 2004, no bonuses were provisioned and the capacity dependence effect can be observed only. From 2004 onwards, gas plants were allowed technology bonuses mentioned in 2.1.3. The effect of bonuses can be observed in terms of divisions in tariffs observable in years 2004 to 2010.

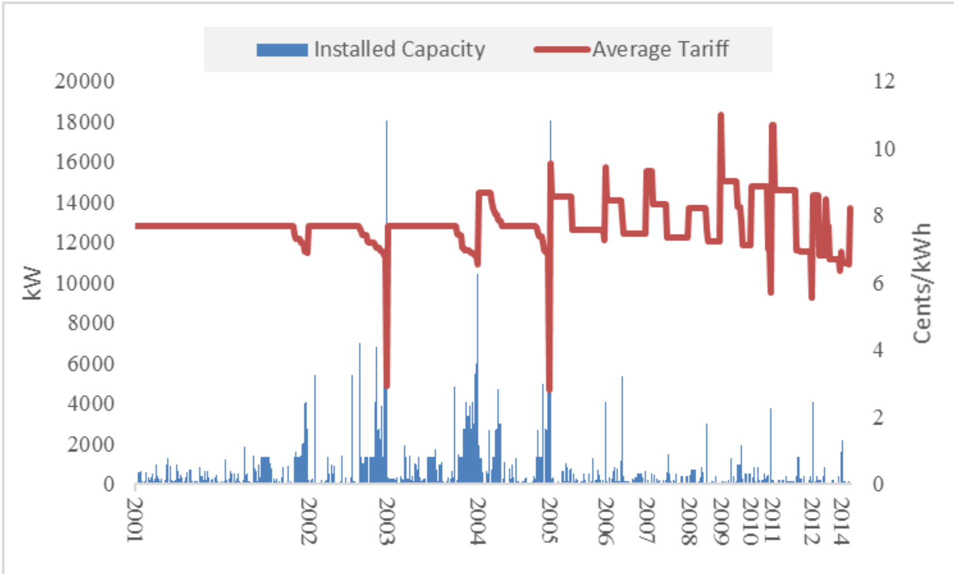

Figure 2.6 Gas plant tariffs (right) and installed capacities (left) ordered in ascending order of installation years and descending tariffs

For hydropower plants, simple tariff schemes are available. Capacity dependence effect and tariff divisions between new and modernized plants can be observed clearly. A particular aspect is that the average tariff falls significantly for few above 7MW power plants.

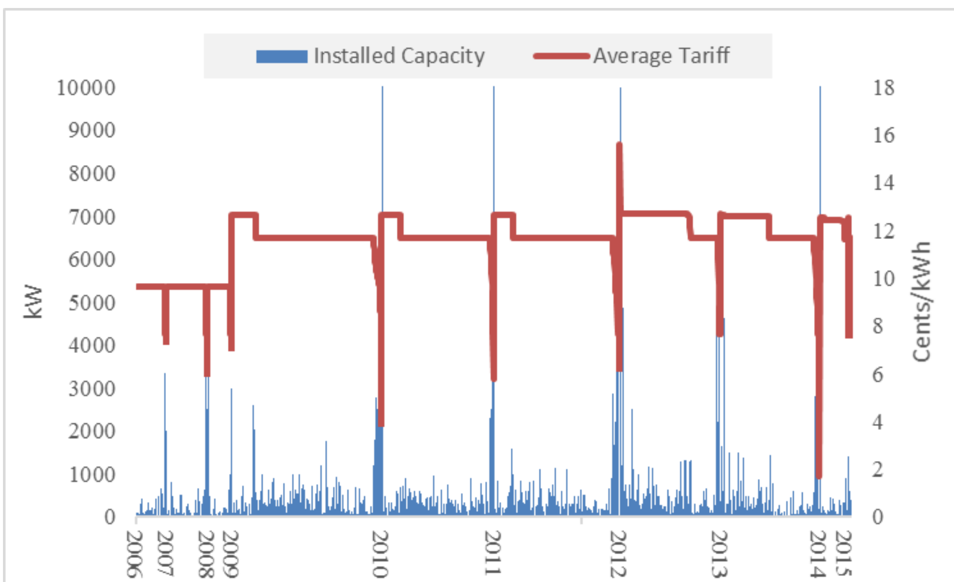

Figure 2.7 Water plant tariffs (right) and installed capacities (left) ordered in ascending order of installation years and descending tariffs (zoomed vertical axis)

A stepped increase can be observed in geothermal plants with introduction of bonuses in 2009 with implementation on plants installed after 2004, mentioned in section 2.1.5 and general tariff increase after 2012 as per EEG-2012.

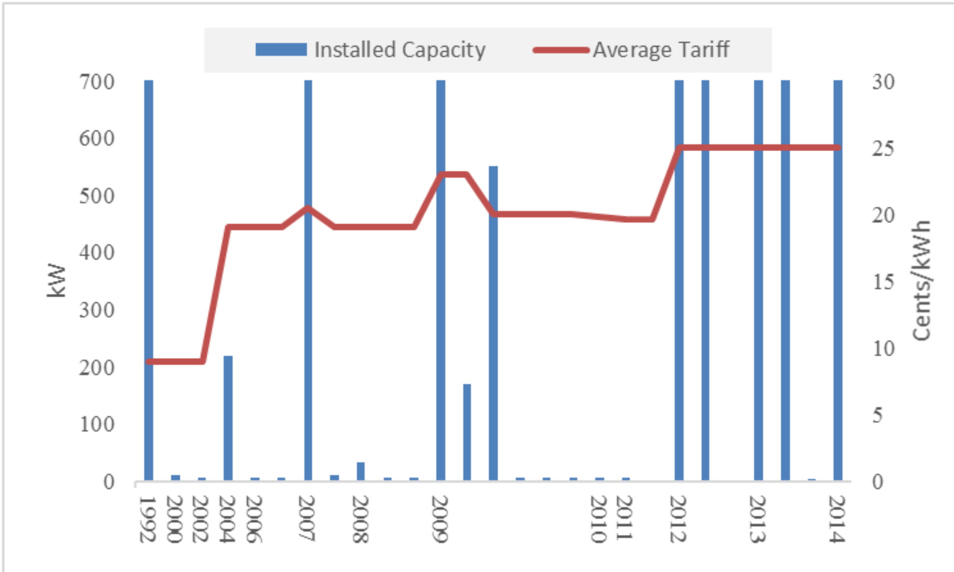

Figure 2.8 Geothermal plant tariffs (right) and installed capacities (left) ordered in ascending order of installation years and descending tariffs (zoomed vertical axis)

For wind offshore plants, two step tariffs show a very simple trend. The peaks indicating higher tariffs correspond to plants carrying EEG-keys for higher starting tariff with reduced number of initial years as mentioned in 2.1.5.

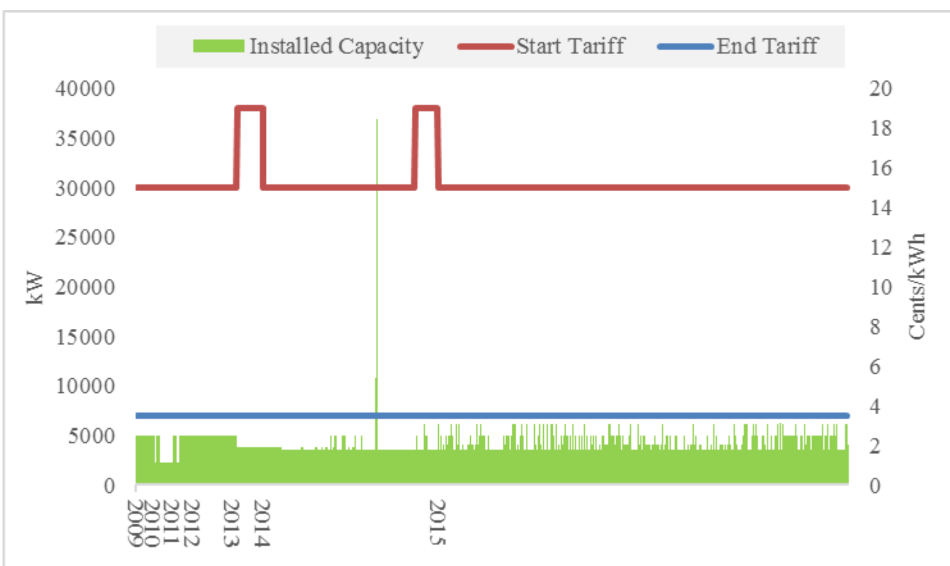

Figure 2.9 Wind-Offshore plant tariffs (right) and installed capacities (left) ordered in ascending order of installation years and descending tariffs

Two step tariffs for wind onshore plants also show a relatively simple pattern. Peaks visible in starting and end tariffs from years 2001 to 2008 are owing to plants with EEG-keys corresponding to system services bonus mentioned in 2.1.4. Three tariff divisions can be observed in start tariff curve after 2009 attributable to repowering, normal plants and plants with system services bonus. However, no such divisions can be observed in end tariff due to end of such provisions as per EEG-2009. Yearly digression in tariffs can be observed while a step increase in starting tariff curve in year 2009, brought by EEG-2009 is also visible.

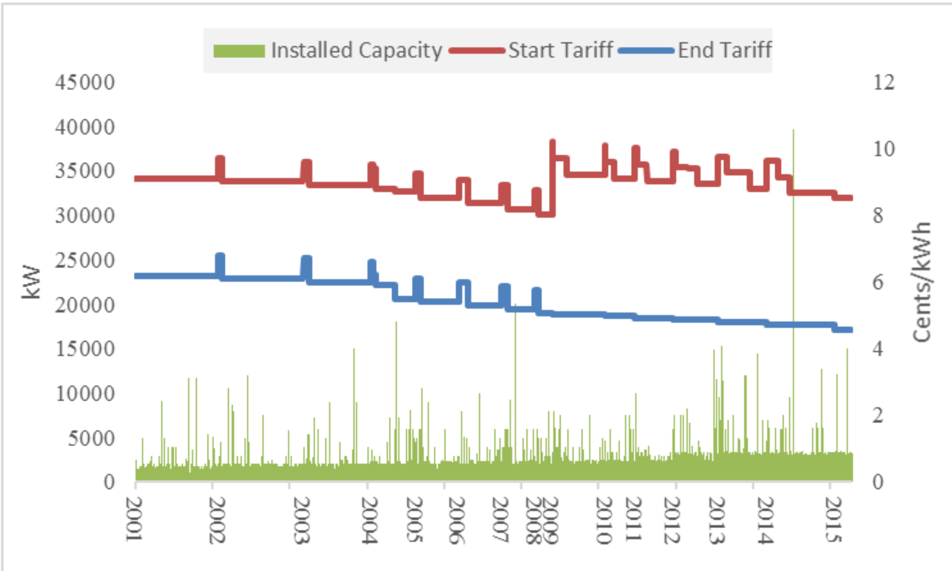

Figure 2.10 Wind-Onshore plant tariffs (right) and installed capacities (left) ordered in ascending order of installation years and descending tariffs

2.2.2 Estimating revenues of RE plant owners C_{EEG}

After the determination of default average tariff for individual RE plants stated above, a python program is developed that implements the model described by equation (5). Methodology regarding estimation of elements of each vector is described below:

Non-direct marketing tariff ***($\overline{T}_{P-NM}$)***: This vector, in general, gets the values of default average tariffs displayed in previous section. However, slight modifications are done for plants coming after year 2014. The default average tariffs are reduced in line with provisions of EEG-2009 mentioned in 2.1.6. These include fixed amount reduction in tariffs for plants falling under category of small plants and 20% reduction for remaining plants. Applicable tariff for wind plants is selected as either start or end tariff based on plant’s installation date and starting tariff period.

During the process of validation of final calculations of above stated model with data available for year 2015 as per (BMWi, 2016b), it was observed that the default average tariffs, described in section 2.2.1, were highly under estimated for biomass, wind onshore and offshore plants as shown in top section of Figure 2.11. For biomass, investigations showed that the average default tariffs, for plants with no EEG-keys but falling under similar installation periods with plants with EEG-keys, were significantly low. The obvious reason was the absence of EEG-keys which led respective plants to get basic tariffs with no bonuses. For biomass, significant bonuses remained applicable from year 2001 to 2012. To get rid of the underestimation in results, an equalization methodology was applied where by the difference of mean of informative plants (with EEG keys) and non-informative plants (without EEG-keys) was added to later mentioned plants.

For wind onshore plants, major cause of under estimation occurred because of the assumption that all wind plants would get an equal start tariff period of 5 years. As per EEG provisions mentioned in 2.1.2, the wind onshore plants get initial tariff periods based on their yield comparison with a reference plant yield. Onshore plants can get an initial tariff period from 16.25 years to 5 years based on land’s wind resource quality from 60% to 150% respectively. However, no such data was available in the (Energymap, 2017). Therefore, a simply approach was adopted. Percentage shares of wind onshore plants installed between 2009 and 2011 against land portions with different wind resource quality were taken from (Agora, 2014). Assuming same shares for all years, a weighted average extension of initial tariff periods was determined that came out as 9 years.

For wind offshore plants, major cause of underestimation was due to many plants missing the EEG-keys for increased start tariff model. The clue was derived from the fact that average tariff paid to offshore plants in 2015 as per (BMWi, 2016b) was 18.4 cents/kWh which indicated that most of the offshore plants must have chosen the increased start tariff provision. To get rid of underestimation, therefore, all offshore plants above 3.6MW were allocated increased start tariff model based on their biggest share in whole offshore plant data base (Energymap, 2017).

Direct marketing tariff $\boldsymbol{\overline{T}_{P-M}}$: This vector is created by adding management premiums of eligible plants into vector $\overline{T}_{P-NM}$ in line with provisions of EEG-2012 mentioned in 2.1.5. Management premiums are applicable to plants constructed from 2012 to 2014 as per EEG-2012. Management premiums for wind and solar plants are set at 0.4 cents/kWh while rest of the plants get 0.2 cents/kWh from 2015 onwards as per §100 of EEG-2014.

Market Factor $\boldsymbol{\overline{MF}_{P-NM}}$: Although direct marketing affects non-significantly on overall costs for EEG eligible plants installed till 2015, the provision of reduced fixed remunerations for non-direct marketed electricity as per EEG-2014 will impact the overall costs arising from future power plants. Therefore, marketing factor is incorporated in the python model and is available for scenario creation. For the scope of this study, average direct marketing factors for each technology have been taken from data of 2015 as per (BNetzA, 2016b) and are assumed to remain same till 2035. These are listed in Table 2.1. During the process of validation of cost results from the model with reference cost data of 2015 as per (BNetzA, 2016b), significant divergences of costs, linked with direct or in-direct marketing, were observed. The obvious reason was the use of same average marketing factor from smallest to biggest plant capacity. It was earlier shown in section 2.2.1, the default tariffs generally decrease slightly with increasing capacities. Since, larger plants are often direct marketed more than smaller plants, as also visible in the depiction provided by (Götz, et al., 2013), the above stated approach led to overestimation of direct marketing costs and underestimation of non-direct marketed energy costs as shown in middle section of Figure 2.11. To get rid of the said error, a simple strategy was adopted. Capacity threshold was defined for each technology based on interpretations conceived from (Götz, et al., 2013) and divergence from reference cost data. All plants with capacities above the threshold (cleavage point), get marketing factor higher than average level while the lower capacities get lower marketing factor such that overall average marketing factor remains unaltered. Deviation factor from average marketing level is determined based on condition that any plant's marketing factor must not rise above 1 or become negative. Deviation factor therefore, depend on total capacity of plants included in $\overline{Cap}_{ijyear}$ and are listed in Table 2.1.

Table 2.1 Average marketing factor and cleavage point per technology to distribute higher and lower marketing factors among higher and lower capacity plants [Source: Self, (BNetzA, 2016b)]

Technology	Average Marketing Factor (%)	Cleavage Point (% of $\sum \overline{\boldsymbol{Cap}}_{\boldsymbol{ijyear}}$)
Wind Onshore	90.5	Not applied
Wind Offshore	99.7	Not applied
Solar	18.6	26.0
Biomass	72.5	33.3
Gas	62.6	Not applied
Geothermal	39.8	85.0
Hydro	53.9	33.3

Other Additions: Two additional revenue components are added to calculated C_{EEG} as per equation (5). One corresponds to payments eligible to self-consumption of building based solar power plants constructed from 2009 to 2012 as per provisions of EEG-2009 mentioned in 2.1.4. Using solar self-consumption and related costs of 2017, predicted by (TSOs, 2016a), average remuneration for self-consumption is determined. A self-consumption factor of 0.3 is multiplied with total plant generation (excluding self-consumption) to determine the yearly self-consumption of the eligible power plants. The self-consumption factor is set in such a way that the model calculated self-consumption revenue of 2017 match with the revenues predicted by (TSOs, 2016a). The other revenue component corresponds to flexibility premiums given to biomass plants mentioned in 2.1.5. The amount of flexibility premiums is set at the level as of 2015 and is assumed to remain constant for future years based on its flat trends in recent past years (BMWi, 2016b).

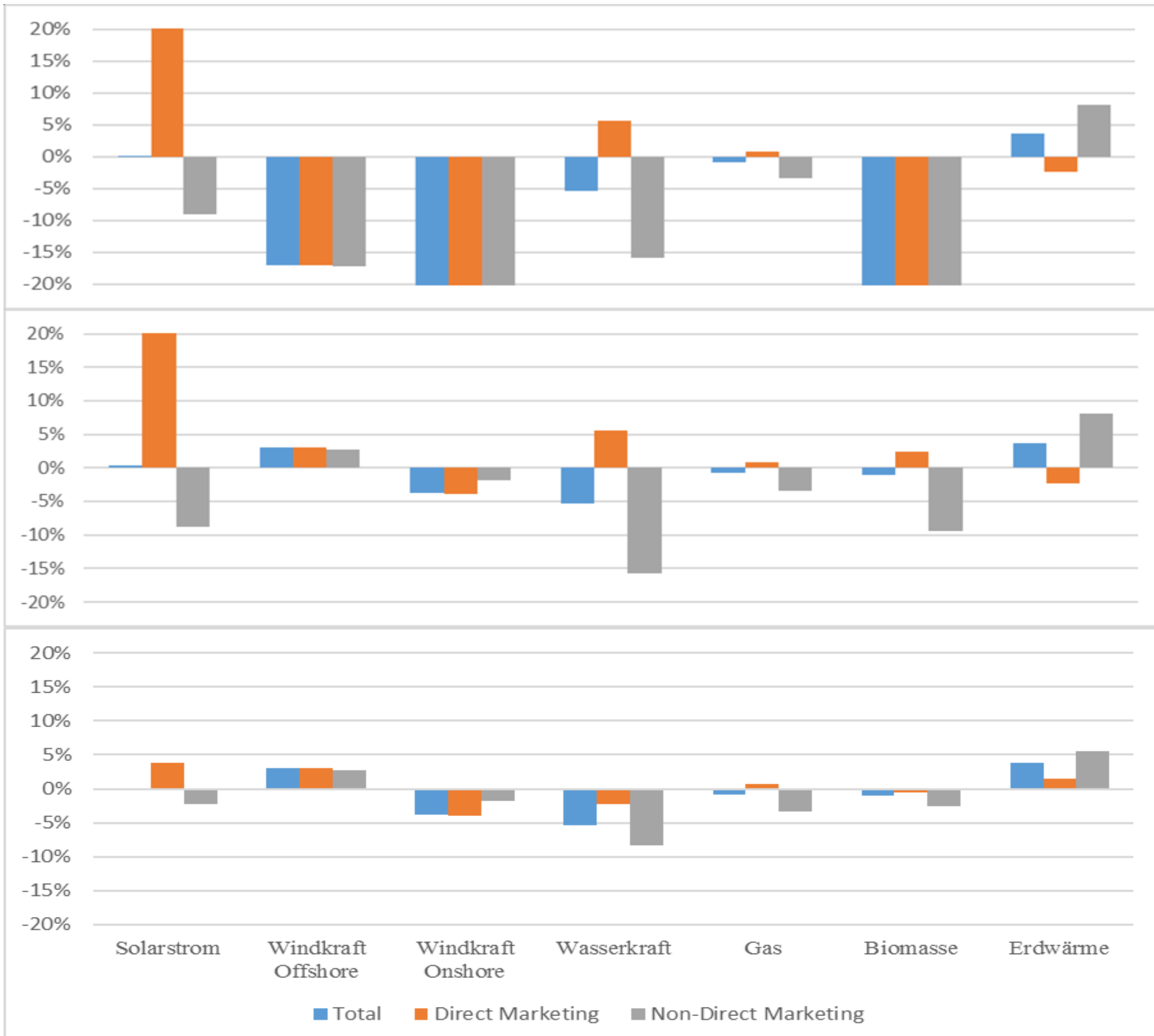

Figure 2.11 Percentage variation of model calculations for EEG revenues of plant owners with respect to reference revenues of 2015 from (BNetzA, 2016b): Without corrections (Top), With non-market related corrections (Middle), With all corrections (Bottom)

2.2.3 Scenario for EEG plants development

A python program is developed that extends the plant based data base (Energymap, 2017) using five yearly scenarios of installed capacities per technology per German province for years 2020, 2025, 2030 and 2035. For the scope of this study, a 2035B scenario for installed capacities per province has been taken from (NEP2030, 2017). Remaining five yearly scenarios are developed based on linear plotting of installed capacities from status quo capacities of 2015 till 2035. Sub-provincial (NUTS3) resolution is utilized in planning the future installations. For each period of 5 years, the declining volume of status quo capacities are compared with target capacities of scenario year on provincial level. If the future scenario demands installation of capacities in a province with no prior installed capacity, the demanded capacity is set in terms of plants put in all NUTS3 regions of the province in equal shares at randomly selected months throughout the five-year period. In case of existence of prior installed capacities, the scenario demanded capacity is translated to NUTS3 regions using share factors as of 2015 as existed in status quo plant data base. The sub-provincial capacity levels of declining status quo plants are then compared with scenario demanded sub-provincial capacities. NUTS3 regions with positive difference are set with new plants as per prior said procedure. NUTS3 region with negative difference are ignored. During calculation of capacity differences, the accumulated new capacities as per previous scenario years is also deducted from future scenario demands. Figure 2.12 give the model scenario results. Yearly total capacities per technology are listed in Appendix Table A.1.

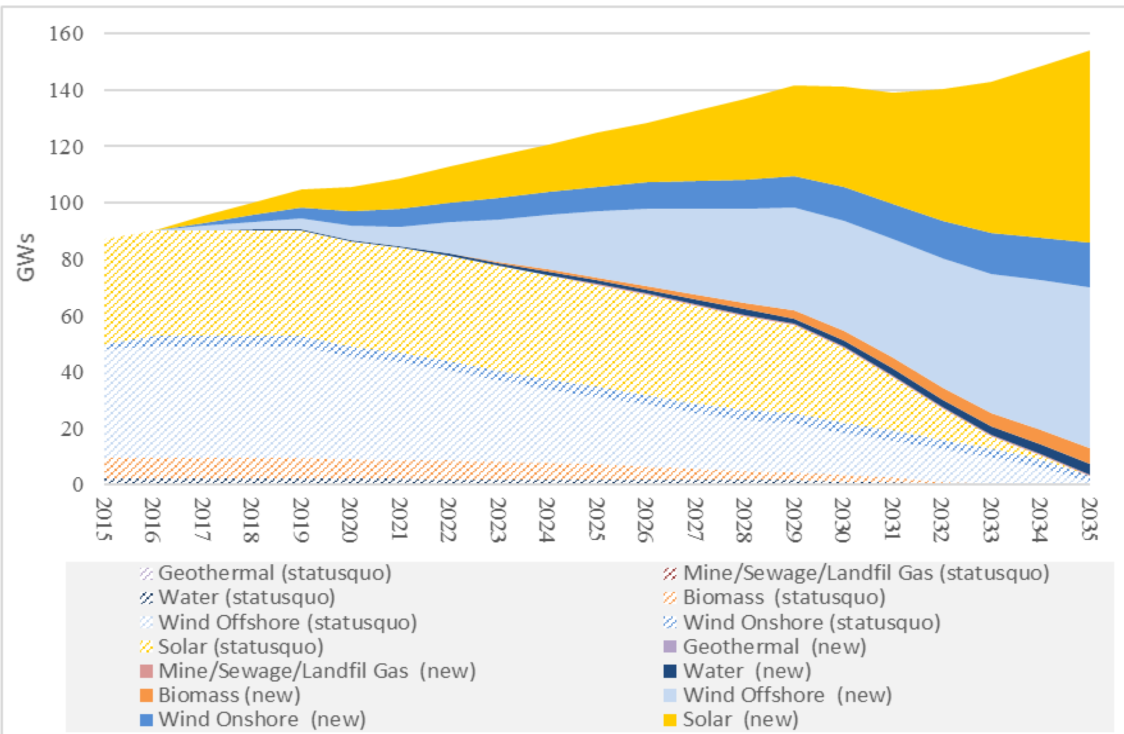

Figure 2.12 Model Scenario: Start year EEG capacities from 2015 to 2035

Estimating the future developments of average default tariffs for EEG technologies is tedious task that requires extensive research around several aspects such as learning curve effects, technical improvements, social acceptance etc. Under limited time constraint, this thesis addresses the future tariff developments in a simpler way. The average default tariff for 2015, 2025 and 2035 are taken from assumptions adopted by (Oeko-Institut, 2016). The tariffs for all other years are simply determined by linear plotting. Figure 2.13 shows the future yearly tariffs as per described methodology. These are also listed in Appendix Table A.2.

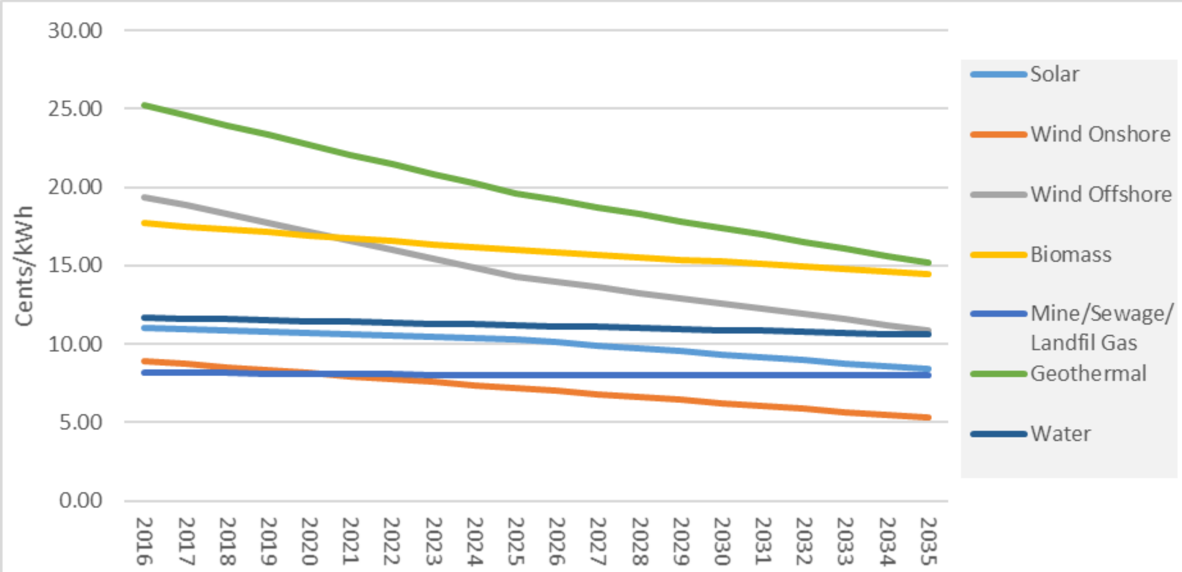

Figure 2.13 Model Scenario: Future development of average default tariffs for each EEG technology [Source: (Oeko-Institut, 2016)]

2.2.4 Scenario of EEG generation

For the scope of the study, the hourly capacity factors for the EEG eligible technologies are assumed same as of 2015, through data obtained from Wuppertal Institute. Figure 2.14 shows the yearly development of EEG generation from 2015 to 2035. EEG generation would rise from 168TWh in 2015 to 268TWh in 2035. In 2035, the proportional shares of biomass, solar, wind onshore and wind offshore energy productions will be 12, 25, 34 and 24% respectively. Yearly total EEG generations per technology are listed in Appendix Table A.3.

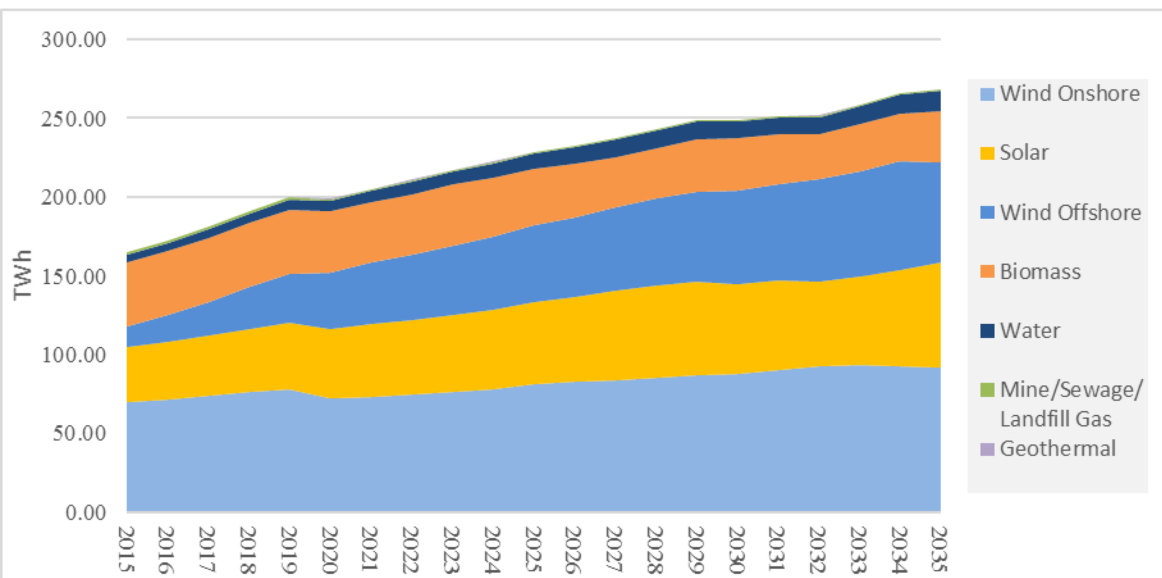

Figure 2.14 Model Scenario: Yearly generation from EEG eligible plants from 2015 to 2035

2.3 Model Results and Validation

Figure 2.15 shows the model results for yearly C_{EEG} plotted against the reference figures for 2015-2017 obtained from (BMWi, 2016b). The model results align well with the reference data. The total costs increase roughly 24% from 2015 to 2024 after which the costs decrease sharply due to expiring high cost power plants. In 2035, C_{EEG} stands 99% of 2015 value.

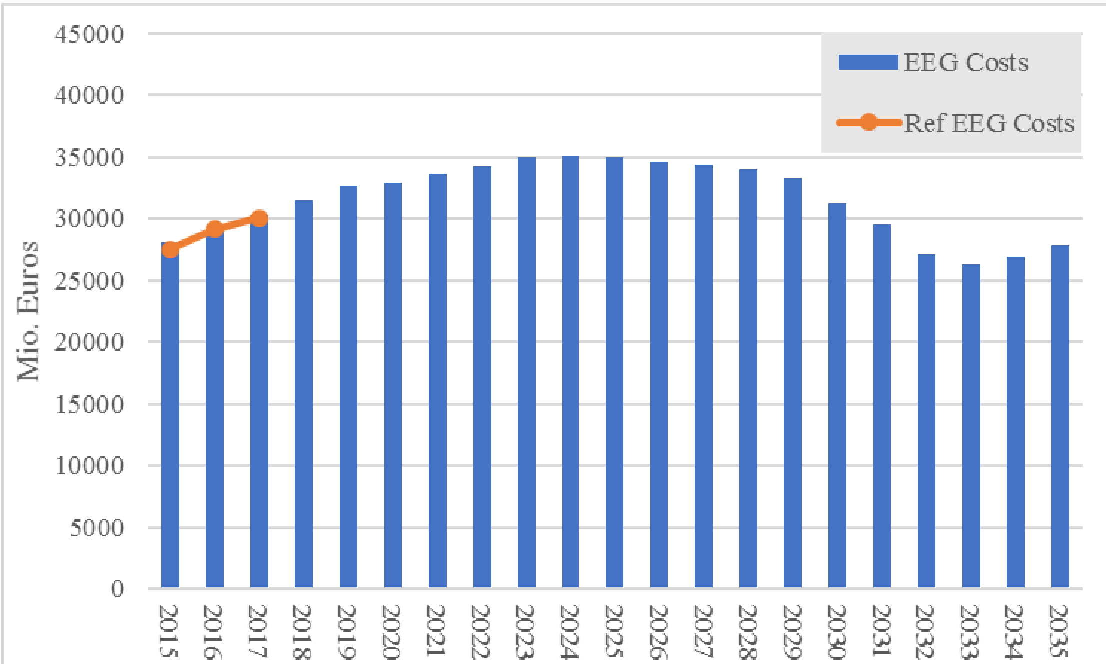

Figure 2.15 Model Results: Yearly C_{EEG} for years 2015-2035 and reference predictions for 2015-2017 from (BMWi, 2016b)

Figure 2.16 shows the model results for the base EEG surcharge for unprivileged consumers plotted against the reference figures from (Oeko-Institut, 2016). The reference study modelled the yearly EEG surcharges using average EEG tariffs for status quo EEG plant capacities. The EEG generation scenario chosen by the reference study is also comparable to the model scenario. The future EEG prices per technology for year 2015, 2025 and 2035 used in the model scenario have also been taken from the reference study. It can be observed that the model results align well with the trend predicted by the reference study. The observable variations can be attributed to average tariff approach adopted by the reference study for status quo plants in early years and a different plant deployment strategy adopted by the reference study in later years. Since, the tabulated information about yearly capacity deployments, energy generation and costs are not available with the reference study, no quantitative comparisons could be presented. Yearly model results for the EEG surcharge are listed in Appendix Table A.4.

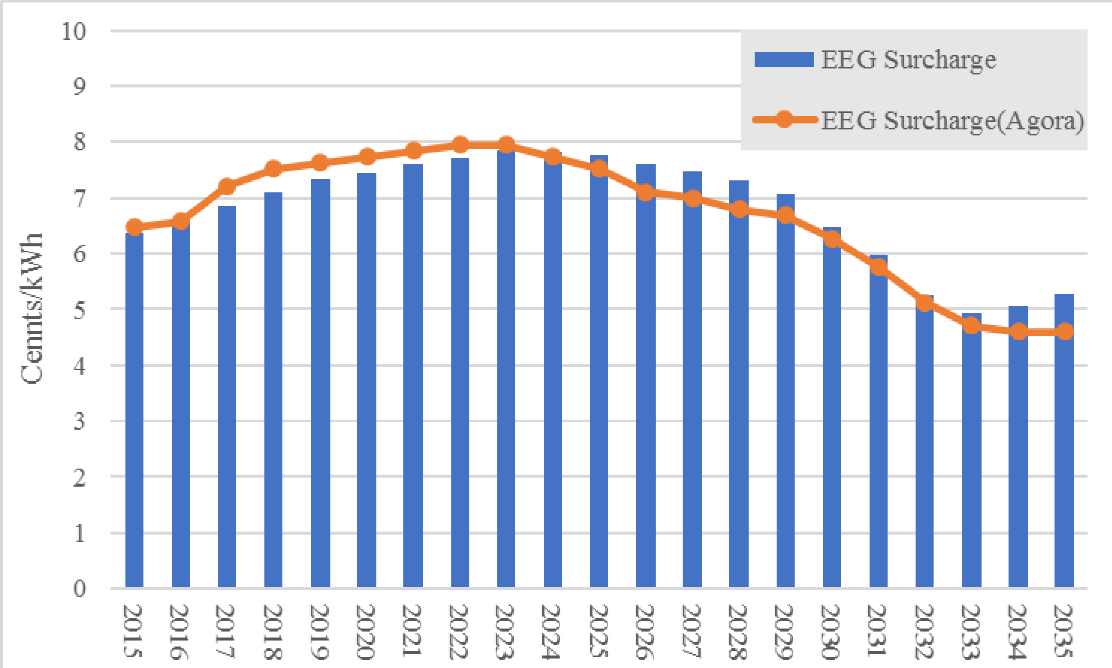

Figure 2.16 Model Results: Yearly base EEG surcharge for unprivileged consumers for years 2015-2035 vs results of same prediction from (Oeko-Institut, 2016)

3 NETWORK CHARGES

3.1 Perspective

Germany has a regulated transmission and distribution system of electricity. The transmission and distribution sector was formally unbundled, through revision of Energy Industry Act (EnWG) in 1998 following EU regulations, however, the regulation of legal unbundling came later in 2005 (Brandt, 2006). The author states that before 2005, the grid companies worked on negotiated access system in agreement with producer and consumer associations. After liberalization, regulated access came into force. As per new system, federal regulator 'Bundesnetzagentur-BNetzA' is responsible to regulate TSOs and those DSOs that have a customer base above 100,000 or that operate in multiple regions. The remaining distribution network operators are regulated by state regulators 'Landesregulierungsbehörde-LRegB'.

German Ordinance on Grid Fees for Electricity or Stromnetzentgeltverordnung (StromNEV) is the main regulatory tool for calculation of overall network charges. Network charges are recovered based on rates per peak demand (KW) and energy consumption (kWh) from consumers. Demand and consumption rates are determined for individual network operator using load coincidence factor methodology. For non-interval metered customers, a standard load profile is assumed while interval metered consumers get individually determined time based demand and energy rates. Starting from 2009, the total collectable revenues (costs) for transmission and distribution business are determined on basis of incentive regulation or Anreizregulierungsverordnung (ARegV). ARegV applies a system of regulations which is close to theoretical framework of price cap regulation in dynamic setting (Joskow, 2006).

(BNetzA, 2017) gives a simplified explanation of cost regulation procedure. ARegV has applied two regulatory periods; 2009-2013 and 2014-2018. For each regulatory period, yearly revenue cap for individual grid operator is determined in a dynamic setting using a base level. Base level is determined for whole regulatory period through a cost assessment, one year before start of new regulatory period. It is based on financial data of the grid operator for the preceding year (called as basis year). The dynamic setting of yearly revenue cap using the such ex-ante determined base level is governed through a pricing formula as under:

$$\boldsymbol{Revenue\ Cap = C1 + (C2 + (1 - V) \times C3) \times (I - PF) \times EF + Q + VC + PA} \quad \textbf{(7)}$$

Where:

C1= Non-influence-able costs	PF= General Productivity Factor
C2= Efficient Costs	EF= Expansion Factor
C3= Non-efficient Costs	Q = Quality Bonus/Penalty
I = Inflation adjustment	VC = Volatile Costs
V =Allocation Factor	PA= Previous Adjustments

Yearly revenue cap is determined at the start of a regulatory period. The base level is first determined using past financial performance of the network operators as described earlier. It contains several cost components that are either influenceable or not influenceable by the grid operator. The cost efficiency benchmarking studies are also executed at the start of each regulatory period. Benchmarking studies use methods like Data Envelopment Analysis (DEA) or Stochastic Frontier Analysis (SFA) and make indices for each grid company. For TSOs, benchmarking is done considering transmission utilities on European level. For DSOs, benchmarking is done among each other. However, not all DSOs are benchmarked. Smaller DSOs can use a simplified process whereby a single general benchmark can be used for all. This general benchmark is the weighted average of national efficiency benchmarks for all DSOs participating in the benchmarking process. To have a fair benchmarking, several structural factors are considered such as number of metering points, network length, supply area and RE connection rate etc. Individual cost efficiency factors, thus determined, are applied to the operator's base level influenceable cost components. It thus results into noncontrollable (efficient) part 'C2' and controllable (non-efficient) part 'C3'. The regulatory formula (7) is so designed that the non-efficient costs are gradually excluded from the yearly revenue caps using an allocation factor 'V'. V is set as 0.2 which serves for the efficiency improvement incentive. The influenceable costs are also subject to inflation and general productivity changes during regulatory period using parameters 'I' and 'PF'. PF accounts the general efficiency improvements in transmission or distribution business. Expansion factor 'EG' enables a DSO, facing change in its structural parameters, to revise revenue cap for rest of the regulatory period. In recent years, it mainly occurred due to increasing RE deployments and is realized in regulatory formula by estimating expansion factor based on increase in number of feed in points of distributed generations. (BNetzA, 2016a) states that this parameter is incorporated to realize the increased costs of lasting changes in grid network as soon as possible. A quality factor 'Q' has been introduced in the regulatory formula in the second round and gives reward or penalizes the grid operators based on the status of their service quality. Service quality factor is mainly determined through recording the System Average Interruption Duration Index (SAIDI) for the grid operators. Previous adjustment factor 'PA' is added to the revenue cap formula which compensates the differences of the yearly fixed caps and generated revenues of the previous regulatory period. This factor provides the volume risk coverage owing to yearly sale volume changes. The total amount is applied uniformly across the years of the next regulatory period. As per ARegV, the regulatory formula (7) will be slightly changed in the third regulatory period. The main change would be the introduction of supper efficiency factor that would reward the superefficient grid operators.

Non-influence able costs 'C1' contain several components and is indicated explicitly by §11 of ARegV. Table 3.1 lists down the general cost categories against grid nature and nature of control. Subsequent sections explain these cost categories individually.

Table 3.1 Cost categories considered for regulated yearly revenues of grid operators

Cost Component	Network Nature	Cost Nature
Approved capital costs(Transmission Expansion etc.)	Transmission	Non-influenceable
System services costs		
Compensations paid to municipalities[1]		
Working capital costs for EEG Sales		
Avoided network charges	Distribution	
Costs of retrofitting necessary for system frequency		
Regular capital costs	Transmission/Distribution	Influenceable
Operation and Maintenance Costs[2]		

1- Compesations paid by TSOs to muncipalities for laying new transmission lines
2- Costs incurred on mainiting operational staff, planning, management, servicing equipment etc

3.1.1 Capital costs

Capital costs originate from the past and future investments by the grid operators, necessary for expansion and strengthening of grid. Considering needs for grid expansion to cope with the RE generation, a comprehensive mechanism is in place that requires the TSOs to carry out certain pre-determined transmission projects. Cost arising from such investments are considered as non-influenceable for the grid operator and grid operator recovers all such costs through generated revenue. Cost arising from other regular investments are subject to operator's cost efficiency and expansion factors as indicated by formula (7). As per ARegV prescribed mechanism, capital costs consist of two components explained below:

Return on capital: It covers the return expected by the grid operator on its investment (Equity) and the interest payable to lenders (Debt). Weighted average cost of capital (WACC) is calculated by assuming equity share at maximum of 40% and rest as of debt. Actual interest status on debt is accounted while return on equity is fixed for each regulatory period. For present regulatory period, return on equity is the sum of risk free rate of 3.80% and risk premium of 3.59% (BNetzA, 2017). Including the corporation tax of 1.66%, the imputed rate of return on equity comes out to be 9.05%. For calculation of asset base, investments older than 2006 are assessed on current costs and new investments are assessed on historic costs.

Depreciation: For long-term satisfactory operation of grid assets, a straight-line yearly depreciation is allowed to grid operators. It is at the grid operator's discretion to either re-invest or distribute it as dividend (BNetzA, 2017). Individual investments vary in life time depending on the asset nature. Individual depreciation life times for different asset categories are indicated in StromNEV. It generally lies around 35-50 years (IE Leipzig, 2012).

3.1.2 Working capital for EEG sales

As per EEG framework, TSOs are responsible for selling the energy produced from EEG generators and distribute the generate revenues among the grid operators as per stipulated procedures. The revenue comes from fixed EEG surcharge and sale of RE electricity in wholesale markets. This whole operation needs a considerable liquid capital in advance. To compensate for the use of this capital from own resources by the transmission grid operators, return on capital is separately allowed to be recovered from generated revenues and is considered in setting revenue cap.

3.1.3 System services costs

Transmission grid operators provide several services in order to operate the grid securely and reliably. The costs incurred for each of these services are separately recorded and passed onto consumers as part of network charges. Functional descriptions of these system services and arising costs are briefly explained below:

Reserve costs: Reserve power is often needed to keep the load and generation balance of power system at all time. In Germany, balance responsible parties (BRP) provide time based schedules for binding generation and load commitments. These commitments can be revised on hourly basis. TSOs monitor the execution of these commitments and if in real time, balance disturbance occurs from BRPs, reserve power is actuated to keep the balance. After such events, proper cost accounting is executed and costs of reserve energy utilized during the event is distributed over the BRPs that deviated the schedules. To keep this reserve energy intact for use in such events, power capacities are contracted in advance through tendering. The capacity charges paid to reserve plants by TSOs are recovered through network charges as one part of system services. The types of capacities contracted are mainly differentiated based on action time and generally named as primary, secondary and tertiary(minute) reserves. Reserve power capacities can be categorized as positive and negative. Positive reserves generate reserve energy while negative reserves absorb excess energy at the time of high generation. Primary reserves ($PC^{+/-}$) are automatically actuated with fastest response time and are shared among cross border TSOs across Europe. Secondary ($SC^{+/-}$) and Tertiary ($TC^{+/-}$) reserves are jointly contracted by all four TSOs with in Germany (Hirth & Ziegenhagen, 2013).

Redispatch and RE Curtailment costs: To avoid grid bottlenecks such as congestion, TSOs are required to take necessary actions. A major part of these actions are the modifications of the generation commitments received from market operator or feed in from RE plants. When a conventional power plant is asked to reduce its generation, appropriate compensations for variable costs are paid by the TSOs to these power plants. At the same time, some other power plants are required to increase generation and are paid accordingly. Costs arising in such activities are accounted as Redispatch costs. RE power plants, supported by EEG, generally enjoy a preferred feed but in some unavoidable circumstances, feed in from such plants is reduced along with backup energy from other non-EEG power plants. RE plants are compensated for their due remunerations as per EEG and accounted as RE curtailment or Einspeisemanagement (Einsman) costs. In recent times, grid delays caused the redispatch and Einsman costs to rise to significant amounts.

Strategic Reserve costs: In recent years, increasing RE deployment has reduced the profit margins for conventional power plants (gas and coal based) and many of such plants have announced departure from generating business (Hinz, et al., 2014). However, these highly flexible power plants are essential for stable and secure system operations. From 27th June 2013, a newly introduced regulation of reserve power plants or Reservekraftwerksverordnung (ResKV) allows the TSOs to buy these plant capacities as strategic reserves to be used for the purposed of redispatch. The costs arising in these operations are separately accounted as strategic reserve costs.

Reactive power compensation costs: Reactive power is essential for maintaining a stable voltage profile across the power system. For such purposes, special devices (capacitive and inductive) are deployed throughout the network. Reactive power capable power plants are also committed (Hinz, et al., 2014). Costs to this category are included in network charges.

Energy losses: Compensation of network losses, is the responsibility of network operators. Network operators compensate these losses by buying this energy through long term contracts. The costs related to such commitments are recovered through network charges.

3.1.4 Avoided network charges

Avoided network charges are an important revenue component of all generation power plants that connect with downstream grids. Its concept is that the decentralized generators are small and expensive then large power plants. However, they are closer to load and avoid power transmission costs. In commercial markets, such expensive plants cannot compete with cheaper centralized power plants. To clear market externality, decentralized power plants are given a fee per generated kWh that correspond to equivalent cost of transporting that kWh over the upstream networks. In this way, such plants restructure their financial streams and able to compete in market (BNetzA, 2016a). Ideally, these payments are done through savings achieved by DSOs due to reduction of their peak demand which is considered while charging grid tariffs to DSOs by TSOs. However, practically these payments have been exceeding beyond the DSO yearly savings due to weaknesses in tariff system (Bayer, 2015). The avoided grid charges are not distributed among EEG and KWK power plants. Instead, these avoided grid charges are paid to TSOs. It is because such plants are paid cost covering fixed remunerations either in form of feed in tariffs or market premiums.

3.1.5 Costs for retrofitting necessary to system frequency stability

In Germany, distributed generation grew steadily since 2000. With time, grid code evolved to ensure network stability. However, due to the time lag in adopting ever evolving necessary changes into grid codes, significant portion of distributed generation was installed that would disconnect at any grid frequency out of the range of 49.5-50.2Hz. (Ecofys, 2014) estimated such capacity as around 48GW. A simultaneous disconnection of such huge capacity can risk a blackout of whole European grid system as the shared primary reserves are not sufficient to handle it. The reason led to development of a special ordinance on Ensuring the Technical Safety and System Stability or Systemstabilitätsverordnung (SysStabV). As per the ordinance, grid operators are responsible for carrying out the necessary retrofitting of applicable power plants to comply to new frequency stability requirements. Retrofitting costs are generally very small, in order of few hundred euros per plant (Ecofys, 2014). Plant operators are reimbursed 75% of the costs. Grid operators can reclaim 50% of such costs through network charges.

3.1.6 Reduced grid charges

§19 StromNEV allows applying reduced network charges for consumers whose style of consumption helps decreasing overall network costs. Consumers whose peak load occurs on times significantly different from system load, can get individual network charge that should be at least 20% of regular network charge. Consumers whose consumption lies above 10GWh and full load hours above 7000 can also get individual network charge at least above 20%, 15% and 10% for full load hours equal to 7000, 7500 and 8000 respectively. Individual network charges are approved by the regulator for whole regulatory period subject to review upon insufficient eligibility in future.

3.1.7 Historical development of network costs

Network costs have showed a rising trend in past years, primarily in distribution sector. Figure 3.1 shows the yearly transmission and distribution costs. Figure 3.2 shows the historical trend of important cost drivers for the overall network costs. It can be observed that the avoided network costs have been consistently increasing due to increasing deployment of decentralized generators. Redispatch and Einsman costs have sharply increased after 2013 due to grid bottlenecks arising of increasing RE generation. On the other hand, reserve costs are decreasing despite the increasing variable RE plants.

As already mentioned, network charges are decided at the grid company level. Therefore, they are diversified across Germany. Status of grid charges as of 2017 for three consumer classes is displayed in Figure 3.3. It can be observed that the northern Germany faces high grid charges owing to high capital costs due to undepreciated investments of last two decades, relatively higher grid expansion costs and lower population density etc. (Hinz, et al., 2015; Bayer, 2015).

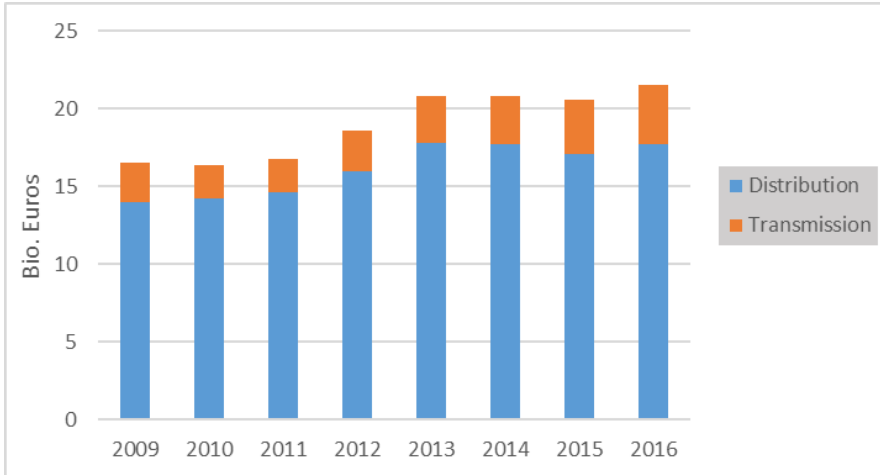

Figure 3.1 Yearly transmission and distribution costs 2009-2016 [Source: (Behringer, 2016)]

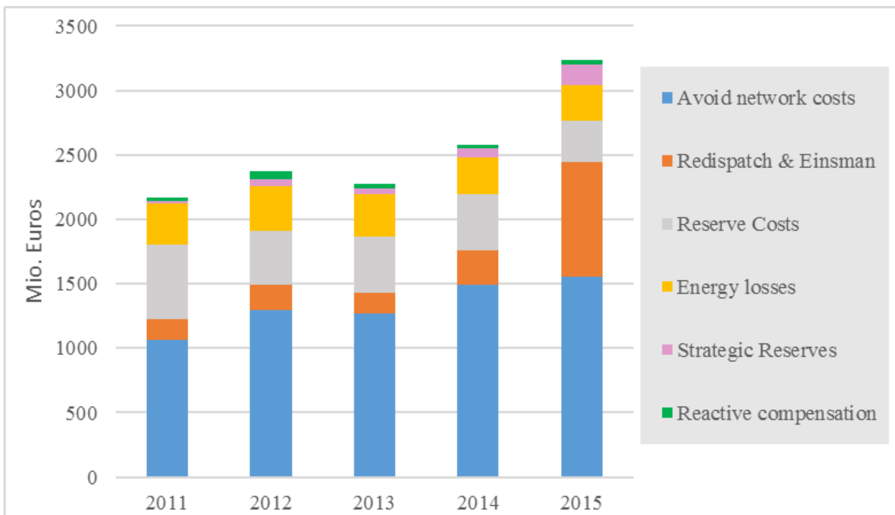

Figure 3.2 Important cost drivers 2011-2015[Source: BNetzA, (Hirth & Ziegenhagen, 2013)]

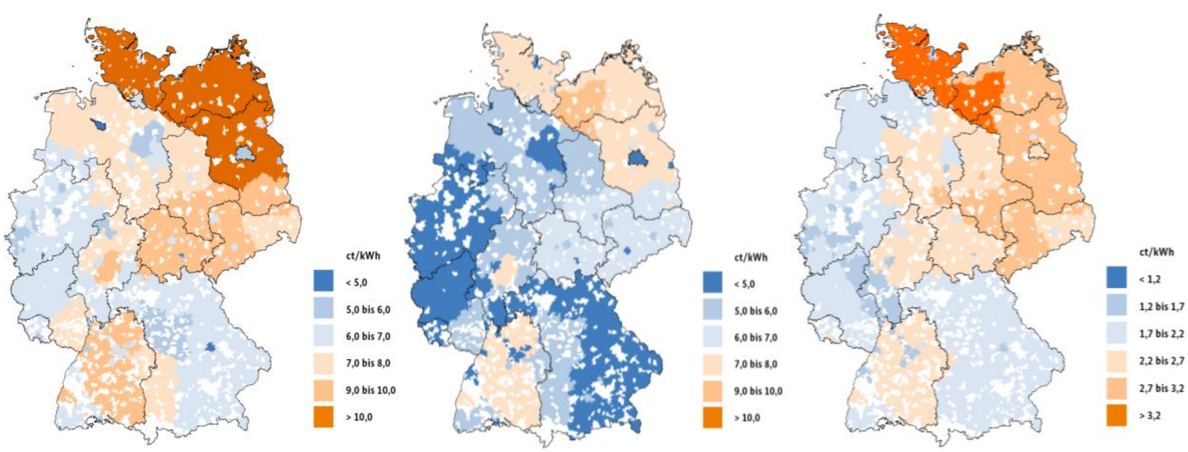

Figure 3.3 Regional network charges for household (left), medium business (middle) and industrial (right) consumers as of 01.01.2017 [Source: BNetzA]

3.1.8 StromNEV-19 surcharge

As mentioned in 3.1.6, some consumer categories get a reduced network charge. Such cases normally result in loss of part of revenue to cover all network costs of network operators. To cover these losses, network operator can pass them to downstream grid operators and ultimately to final consumers in form of a special surcharge. Regarding application of this surcharge, three types of consumption categories have been established:

***Category-C**:* Consumption above 1GWh of manufacturing or rail industry whose electricity consumption costs for previous year are above 4% of their sales.

Category-B: Consumption above 1GWh for consumers who do not lie in category C.

Category-A: Consumption below 1GWh for all consumers

§19 StromNEV also provides the maximum limit of the surcharge to be 0.05 and 0.025 cents/kWh for consumer type B and C respectively. Figure 3.4 gives the surcharge levels for three categories over recent years. It can be observed that category B and C get regulation limited surcharge levels. The lost revenue is thus recovered from category A, which results in higher surcharge level for those consumers.

3.1.9 Offshore liability surcharge

As per fundamental regulation of all EEG Acts, transmission operators are responsible to provide grid connection to offshore wind installations and maintain it. However, it is more challenging to connect offshore wind power plants then other RE plants especially when the plants are situated far from the coast. Furthermore, for German grid, the offshore wind power installations are concentrated within territories of two transmission operators. In response to financial concerns of these transmission operators regarding connection of offshore wind power plants, a special fund was allowed as per §17f EnWG, starting from 2013, above the regulated revenue cap allowed for covering network costs. The fund covers the liabilities of respective transmission operators arising due to delayed completion of grid interconnections or connection service failures related with offshore wind installations. The fund is recovered through offshore liability surcharge or offshore haftungsumlage (OHU), using same methodology as mentioned for StromNEV-19 surcharge in section 3.1.8. Figure 3.4 gives the surcharge levels for three categories over recent years. For years 2016-17, the OHU surcharge level was not high enough to regulate category-B surcharge level. Furthermore, the positive balances from past years resulted in negative surcharge values for category A consumers.

3.1.10 Interruptible load surcharge

Since the incorporation of Disconnect-able Loads Regulation or Abschaltbare Lasten Verordnung (AbLaV) in 2012, demand side management is promoted on the high voltage level. As per regulation, the industrial loads, which are connected to grid system at above 110KV level and can reliably reduce consumption if requested by the transmission operators, can get special remunerations in this regard. The eligible parties are pre-qualified by the transmission operators and participate in weekly tendering. TSOs provide volume requirements for dis-connectable loads subject to review and adjustment by BNetzA based on periodic demand analysis for each TSO. Successful parties get remunerations as per demand and energy rate. Costs arising in this respect are equalized through a special interruptible load or AbLaV surcharge. The surcharge is applied across the consumer classes without any privileges. Figure 3.4 gives the AbLaV levels for past years which remained as low as 0.006 cents/kWh. There was no such surcharge in 2016 due to regulator transitional period.

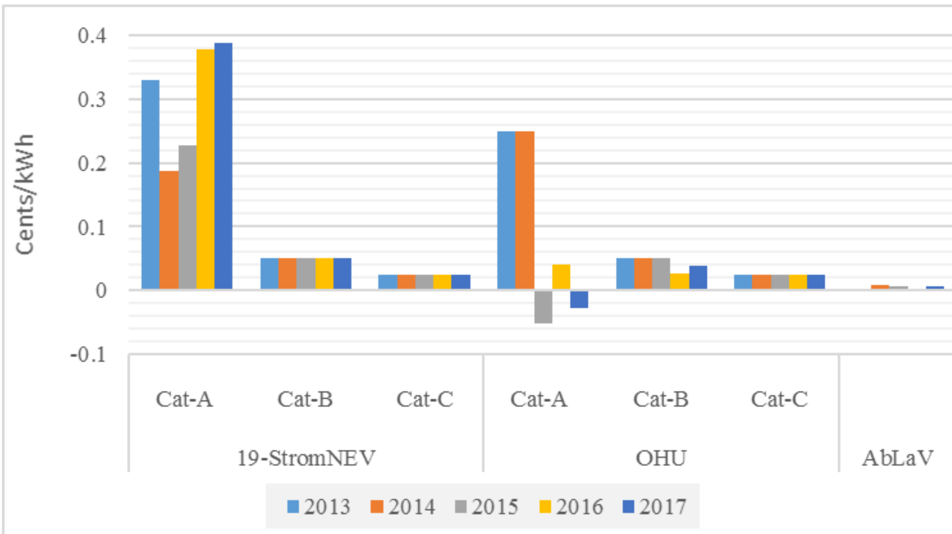

Figure 3.4 Surcharge levels for category A, B, C for years 2013-17 [Source: Netztransparenz.de]

3.2 Model Description

As it is already mentioned that network charges are different for different DSO consumers. Under the scope and time constraints of this thesis, geographical variations are not modelled, instead the costs, mentioned in section 3.1, are estimated on whole country level. Network charges are applied on consumers based on the voltage level that they connect with in the grid system. Costs associated with any upstream voltage network is passed on to directly connected consumers based on their share of energy consumption. Electricity fed to downstream networks is also treated same i.e. upstream network operators charge downstream operators in similar manner as directly connected industry regarding calculation of grid charges. The similar mechanism of payments continues in downstream networks till the end user is reached. For modeling, two segregations are assumed for the whole grid system in Germany as described in (Hinz, et al., 2014). First segregation features high (usually 110KV) and medium (usually 35KV) voltage networks which generally fall under DSOs. Although a small portion of industry is also connected with TSO networks, but in this study, it is assumed that all industrial loads connect at high/medium voltage (MHV) network because of limited past cost data availability. Second segregation features low voltage (usually 0.4KV) networks which connect all household and small to medium enterprises. Equations (8) and **(**9**)** present a simplified relation of average network charges with total network costs (NC), for a target year and for above described consumer categories, based on the two segregations power grid.

$$Network\ Charge_{industry} = \frac{NC \times f_{MHVcost} - NC \times f_{exemptions}}{Con \times f_{MHV-TWh}} \tag{8}$$

$$\boldsymbol{Network\ Charge_{HH/SME}} = \frac{\boldsymbol{NC} \times (\mathbf{1} - \boldsymbol{f_{MHVcost}})}{\boldsymbol{Con} \times (\mathbf{1} - \boldsymbol{f_{MHV-TWh}})} \tag{9}$$

$$\boldsymbol{Network\ Charge_{nonprv\_industry}} = \frac{\boldsymbol{NC} \times \boldsymbol{f_{MHVcost}}}{\boldsymbol{Con} \times \boldsymbol{f_{MHV-TWh}}} \tag{10}$$

Where:

$f_{MHVcost}$= *Factor to determine amount of NC occurred on MHV network level. It is estimated by* (Hinz, et al., 2015) *as 28.4% in 2014. This study assumes it constant for all years. In python model, it is is linked with yearly consumption at MHV level through simple proportionality factor of* $\frac{Con \times f_{MHV\ TWh}}{Con}$.

$f_{exemptions}$= *Factor to determine amount of NC not paid as privilege. It is estimated as 5.4% based on ratio of total costs recovered through StromNEV-19 surcharge and network costs of 2016 taken from* (Behringer, 2016). *The former costs are estimated using StromNEV-19 rates of 2016 and consumption amounts of category A, B, C as per* (TSOs, 2016b). *This study assumes* $f_{exemptions}$ *constant for all years.*

$f_{MHV-TWh}$=*Factor to determine amount of TWh consumed at MHV network level*. (Hinz, et al., 2015) *estimates it as 57% of total consumption in 2014. This study assumes it constant for all years.*

Con= Consumption in target year (assumed same for all years as of 2015)

It can be seen in equation (8), that for calculating average network charges for all industry, the MHV network costs are first reduced by the exempted volume of costs not paid by privileged industry. Equation (**10**), however, includes no such reduction and indicates the average network charges that are applied to non-privileged industries. The provisions of StromNEV are so designed that smaller consumers such as household or small to medium enterprises do not qualify for any exemptions. Therefore, no such exemptions are considered in equation (**9**).

The costs not paid by the privileged industry, coming from equation (8) are recovered through additional surcharge as per §19 of StromNEV. The model calculates the surcharge for categories A, B and C as per simple procedure mentioned in section 3.1.8. OHU and AbLaV surcharges are also calculated in similar fashion, however, the relevant total costs for these categories are directly given by the user. For the scope of this study, the total costs for these categories are fixed to levels as of 2017 available from prognoses provided by TSOs, accessible through (netztransperenz, 2017).

Network costs (NC) are calculated as per simple self-explanatory equation (11). Costs for energy losses $TDloss_{costs}$ are estimated using a simple cost rate $R_{L\text{-}cost}$ and losses factor $f_{L\text{-}TWh}$. $R_{L\text{-}cost}$ and $f_{L\text{-}TWh}$ are estimated as 10.75 Mio Euros/TWh and 5.2%, at levels as of 2015, taken from (BNetzA, 2016a) and are assumed constant in this study. Methodology adopted to calculate rest of cost components in equation (11) is explained in subsequent sections.

$$NC = T_{costs} + D_{costs} + TDloss_{costs} + Services_{Costs} \tag{11}$$

3.2.1 Transmission Costs (T_{costs})

Transmission costs comprise of capital costs $C_{T\text{-}capital}$, operating costs $C_{T\text{-}op}$ and services costs (will be discussed separately). Compensation payments mentioned in Table 3.1 are not considered in modeling owing to their small share and high unpredictability. Capital costs arise from yearly depreciations D_T of invested assets and total return R_T on investments for network expansion $I_{T\text{-}new}$, investment for network replacements $I_{T\text{-}rep}$ necessary for long term stable operations and monthly working capital $I_{T\text{-}WC}$ needed for managing EEG sales. Returns of $I_{T\text{-}WC}$ and $I_{T\text{-}rep}$ are determined from assumed investments of 115 and 180 Mio. Euros for all years using 2015 estimates provided by (Hinz, et al., 2014) respectively, however, model provides flexibility to change these values on yearly basis for different user scenarios. For return on investment calculations, WACC of 6.59% is used based on methodology mentioned in section 3.1.1. For debt, interest rate of 4% is used (Hinz, et al., 2014).

To calculate yearly grid expansion investments $I_{T\text{-}new}$, a simple strategy is chosen. A linear line is plotted using two data points on a graph between needed investment I_t (independent-axis) vs the achievable increase in RE share f_{RE} (dependent-axis). First data point is taken from (Dena-Netzstudie II, 2010). From the study, the total investments needed till 2020 are determined by aggregating yearly investment estimates against three alternatives on average basis. I_t comes out, thus, as 11.8 Bio. Euros against the target of 39% RE share in gross energy consumption (gross production minus exports). This investment estimate is based on the year 2010. Yearly investments for expansion of transmission network done from 2011 to 2015 are therefore subtracted from the estimate to get an approximate estimate at the end of 2015 using data available in (BNetzA, 2016a). To get f_{RE}, the RE share in gross consumption in 2015 i.e. 31.7% is subtracted from 39%. Second data point is taken from first draft of network development plan submitted by TSOs on 31st January 2017 (NEP2030, 2017). NEP2030 gives the total planed investment of 35 Bio. Euros against target RE share of 52% (average of given range) till 2030 under scenario-2030B. The investment estimate also includes 6 Bio. Euros cost of start Netz. Since, the estimates are given with 2017 as base year, investments done in 2016 are included to set the reference year to 2015 in common with previous data point. The developed graph can be further loaded with more data points in future to increase accuracy. The mathematical function so created, is then used to determine yearly investments for transmission network for any given target RE share in gross consumption. Figure 3.7 shows the cumulative transmission investments against target RE share in gross consumption derived for above stated methodology.

For any target year starting from 2016, rate of return R and depreciation D is determined by methodology presented in (Hinz, et al., 2014) through equations (**12**) and (13) respectively.

$$R = I_{hist} \frac{(1 + WACC)^T \times WACC}{(1 + WACC)^T - 1} + I_{from2016} \times WACC \tag{12}$$

$$\boldsymbol{D = \frac{I_{from2016}}{T}} \tag{13}$$

Where:

I_{hist} *(2015) =* P_{2015}

$I_{hist}(target\ year) = I_{hist}(previous\ year) - \frac{P_{2015}}{T}$

$I_{from2016}(target\ year) = I_{from2016}(previous\ year) - D$(previous year)

I_{hist}= Undepreciated portion of accumulated historical investments before 2016

$I_{from2016}$= Accumulated investments starting from 2016 excluding yearly depreciations

P_{2015}= Value of undepreciated grid infrastructure at the end of 2015

T = Average period of network infrastructure depreciation

Transmission specific undepreciated portfolio value $P_{T\text{-}2015}$ is estimated by first determining $P_{T\text{-}2012}$ as per methodology described by (Hinz, et al., 2014) whereby the per km rate of transmission line/cable and per MW rate of voltage transformation system of 2013 are multiplied to respective assets owned by TSOs in 2012 and aggregated. It is corrected with last 20 years of inflation and multiplied with average portfolio depreciation factor. (Hinz, et al., 2014) provides the estimates for average portfolio depreciation factors for all TSOs, whose average comes out as 35% and is used in this model. This method determines infrastructure value as historical costs rather than replacement costs. For extending the results to 2015, an approximate approach is adopted where by the investments of 2012-2015 are added to $P_{T\text{-}2012}$ and fixed rate depreciations are excluded using average end of life period of grid infrastructure as 40 years. Return on historical investments, 1st term of (**12**), is an implementation of annuity method. Direct method, as used with investments from 2016 onwards, is not used here due to non-availability of data regarding age structure of historical investments (Hinz, et al., 2014).

Transmission operating costs $C_{T\text{-}op}$ are calculated by summing indirect or overhead costs and costs of O&M for the transmission assets. Overhead costs are considered as 868 Mio. Euros/GWh as stated by (Hinz, et al., 2014). Costs of O&M are linked with grid assets in operation which are assumed under this study as the undepreciated investments. (Hinz, et al.,

2014) gives an average O&M costs factor of 3.1% per undepreciated investments, which is also considered here to calculate increase of O&M costs above 2015 base level.

3.2.2 Distribution Costs (D_{costs})

As described in sections 3.1.4 and 3.1.5, apart from general capital costs $C_{D\text{-}capital}$, overhead and O&M costs $C_{D\text{-}op}$, costs for distribution operators also include payments of avoided grid charges to distributed generators and costs occurring due to retrofitting of renewable energy plants. However, it does not include costs of most of grid services such as reserves or redispatch, which fall under TSO scope. Like transmission grid, the capital costs for distribution grid arise from yearly depreciations D_D of invested assets and total return R_D on investments for network expansion/strengthening $I_{D\text{-}new}$ mainly driven by increasing decentralized RE power plants and investment for network replacements $I_{D\text{-}rep}$ necessary for long term stable operations. Yearly depreciations and returns on historical investments and investments starting from year 2016 are calculated in same fashion as described by equations (12) and (13) in section 3.2.1. As an exception, the parameter $P_{D\text{-}2015}$ is extended from $P_{D\text{-}2014}$ as per prior described procedure. $P_{D\text{-}2014}$, however, could not be determined from assets, asset rates and inflation rates due to lack of data and complexity owing to huge number of DSOs operating in Germany. Instead, back calculation of equations (12) and (13) is done from the estimated capital costs of 2014 as 3.1 Bio and average depreciation of 37% on historical assets, provided by (Hinz, et al., 2015).

To calculate yearly distribution grid investments $I_{D\text{-}new}$, similar strategy is chosen as described in section 3.2.1. Two data points are taken from (Dena-Verteilnetzstudie, 2012). First data point belonged to leading scenario (Leitszenario) which was based on scenario B of NEP2012. As per scenario, 27.5 Bio. Euros are needed from 2010 to 2030 to reach RE share of 62% in total installed capacity. Second data point belonged to federal state scenario which was based on scenario C of NEP 2012. As per scenario, 42.5 Bio. Euros were needed from 2010 to 2030 to reach RE share of 82% in total installed capacity. RE share in gross consumption as per first data point can be assumed as 50% since scenario B in NEP studies generally target official targets set by German government. For second data point, 82% of share of RE in installed capacity is a very ambitious target. Since, RE share in gross consumption depends on most economical consumption methodology, it is very complex to estimate such share based on mere knowledge of RE share in installed capacity. For this study, to avoid complexity and delays, most ambitious target of RE share of 58% in gross consumption is chosen for second data point. It is chosen from the most ambitious scenario out of all scenario results collected under study (BDEW, 2010). Figure 3.7 shows the cumulative distribution investments against target RE share in gross consumption derived for above stated methodology.

To calculate distribution costs, apart from capital costs $C_{D\text{-}noncap}$, a simple strategy is adopted. The cost level is estimated for year 2015 around 10 Bio. Euros from assumption taken from

(Hinz, et al., 2014) which considered around 80% of all distribution grid revenues associated with non-capital costs. The resulting cost level is subtracted by costs of avoided grid charges paid by DSOs in 2015 as per (BNetzA, 2016a). From 2016 onwards, cost level so calculated is added with two cost heads to make yearly $C_{D\text{-noncap}}$. First is the yearly avoided grid charges C_{av} set at the level of 2015 in scope of present study. Second is the new O&M costs arising from new investments determined by considering factor of 3.1% as stated earlier in section 3.2.1. Costs incurred to maintain system stability as described in section 3.1.5 are not considered in model since they are of temporary nature and have a nonsignificant share in $C_{D\text{-noncap}}$.

3.2.3 Services Costs

Costs for reactive power services are addressed by simply fixing the amount as of 2015, however, the yearly value can be adjusted as per user needs. Costs of remaining services are modelled as follows:

Reserves costs: (Hirth & Ziegenhagen, 2013) states that as per several Europe based studies, primary reserve ($PC^{+/-}$) capacities do not depend on increase in RE installations. However, increased RE installations does impact the amount to be contracted for secondary and tertiary capacities $Cap_{ST+/-}$. The author acknowledges that although, from historical data, it can be observed that total reserve requirements have gone down while RE installation share was increasing, it can be attributed to increasing accuracies in forecasting and better handling of TSOs in managing control areas in cooperation with each other. Nevertheless, through convolution based assessment of historical data, the author comes up to the results that the reserve requirements would increase in the range of 1.5 to 6.5% per GW increase in wind and solar installations against the 60% to none improvement in variable RE forecasting techniques respectively. Considering the past decreasing trend in reserve costs, the lowest increase factor is considered for modeling under present study. Costs for primary reserves are assumed to remain same as of 2015, however, the yearly primary capacity is available as input to user to adjust as per scenario needs. Costs per MW for secondary and tertiary reserves are estimated as average of positive and negative control capacity costs provided by (BNetzA, 2016a). Yearly Cap_{ST+-} is determined by using above stated factor and the EEG capacity development scenario explained in section 2.2.3.

Redispatch & Einsman: The need of redispatch and Einsman arises because of grid limitations. In recent years, these measures are rising mainly due to rising renewable energy penetration into the grid. As per (BNetzA, 2016a), around 92% of all Einsman measures were taken on wind and solar based energy generators. Therefore, the costs arising from these measures can be related to grid infrastructure investments and renewable energy generation. In python model, yearly grid investments drive the volume of redispatch and Einsman measures in TWh. The methodology is explained below.

A redispatch and Einsman index ($RdEn_{index}$) is defined as the ratio of cumulative TWh of redispatch and Einsman ($RdEn_{cum}$) to yearly EEG generation. Two reference yearly $RdEn_{index}$ curves are created using yearly EEG generation scenario from section 2.2.4 and three data points listed in Table 3.2 . One curve is for no grid delay case ($\overline{\mathrm{RdEn}}_{\mathrm{nodelay}}$) i.e. the case when yearly grid investments $\bar{I}_{ref}$ are done as would be needed to reach goal of attaining 50% of RE share in gross consumption in 2030 as per scenario 2030B from (NEP2030, 2017). This results in a yearly investment of 3,547 Mio. Euros (T+D). Underlying assumption is that the grid development measures are designed to limit the $RdEn_{cum}$ at 2010 level. In this curve, the $RdEn_{index}$ linearly decreases from 2016 level to 2010 level from year 2016 to 2023 and afterwards retains the level till 2035. The second curve is for the case of a ten-year delayed grid development $\overline{\mathrm{RdEn}}_{\mathrm{delay}}$ using study (Agora, 2013). The study analyzed the effects of grid delays on overall system costs. It stated that in 2023, the redispatch and Einsman measures would be around 10.2 TWh along with EEG production around 254TWh as per scenario B of NEP2013, excluding the assumed 20TWh of non-EEG production (BNetzA, 2016a). This is when:

1. The grid development (also called Start Netz) required as per 2013 amended Electricity Grid Expansion Act or Energieleitungsausbaugesetz (EnLAG) complete up till 2023.

2. The grid development measures defined by the then 2013 version of Grid Expansion Law or Bundesbedarfsplangesetz (BBPlG), that were due till 2022, would be delayed ten years

Considering above study and data point 3 in Table 3.2, $\overline{\mathrm{RdEn}}_{\mathrm{delay}}$ was designed in such a way that the $RdEn_{index}$ would decrease linearly from 2016 level to 2023 level for the years 2016-2023 and then decrease to 2010 level until 2033 (after ten years) and stay same onwards. Under such scenario, however, the grid investments must be enough to cover Start Netz costs, which are roughly 6 Bio. Euros as per (NEP2030, 2017). The $\overline{\mathrm{RdEn}}_{\mathrm{nodelay}}$ and $\overline{\mathrm{RdEn}}_{\mathrm{delay}}$ curves are shown in Figure 3.5.

Table 3.2 Model Parameters: Reference data points for $\overline{\mathrm{RdEn}}_{\mathrm{nodelay}}$ and $\overline{\mathrm{RdEn}}_{\mathrm{delay}}$ curves

Year	EEG Generation (TWh)	$RdEn_{cum}$ (TWh)	$RdEn_{index}$ (%)	Source
2010	82.3	0.433	0.52	(BNetzA,2011)
2016	172	8.92	5.2*	(BNetzA,2015), (BDEW, 2017)
2023	254	10.2	4.0	(Agora, 2013), (NEP2013)

** For calculating 2016 level of $RdEn_{index}$, redispatch TWh for 2016 were taken from* (BDEW, 2017) *while Einsman TWh were considered at level as of 2014 from respective BNetz's monitoring report of 2015 due to non-availability of 2016 data. Value for 2015 was not considered as it was very high due to a grid bottleneck which got cleared in 2016* (BNetzA, 2016a).

Figure 3.5 Model Parameter: $\overline{\mathbf{RdEn}}_{\mathbf{nodelay}}$ and $\overline{\mathbf{RdEn}}_{\mathbf{delay}}$ curves

Once the $\overline{\mathrm{RdEn}}_{\mathrm{nodelay}}$ and $\overline{\mathrm{RdEn}}_{\mathrm{delay}}$ curves are defined, the input $\mathrm{RdEn}_{\mathrm{cum}}$ for any year 'y' is determined by following equation:

$$\boldsymbol{RdEn_{cum}}(\boldsymbol{y}) = \left[\overline{\mathbf{RdEn}}_{\mathbf{nodelay}}(\boldsymbol{y}) + \boldsymbol{delay_{fctr}} \times \left(\overline{\mathbf{RdEn}}_{\mathbf{delay}}(\boldsymbol{y}) - \overline{\mathbf{RdEn}}_{\mathbf{nodelay}}(\boldsymbol{y})\right)\right] \times \boldsymbol{EEG\ Generation}(\mathbf{y}) \quad \mathbf{(14)}$$

Where the $\mathrm{delay}_{\mathrm{fctr}}$ ranges from 0 to 1 for delay in grid investments from 0 to 10 years. The delay in grid investments is determined by subtracting cumulative scenario investment of the year 'y' from cumulative $\bar{I}_{ref}$ and dividing it by 3,547 which is the reference yearly investment for grid development without delay described before. Figure 3.6 shows the upper and lower $\mathrm{RdEn}_{\mathrm{cum}}$ curves for corresponding 10-year delay and no delay cases.

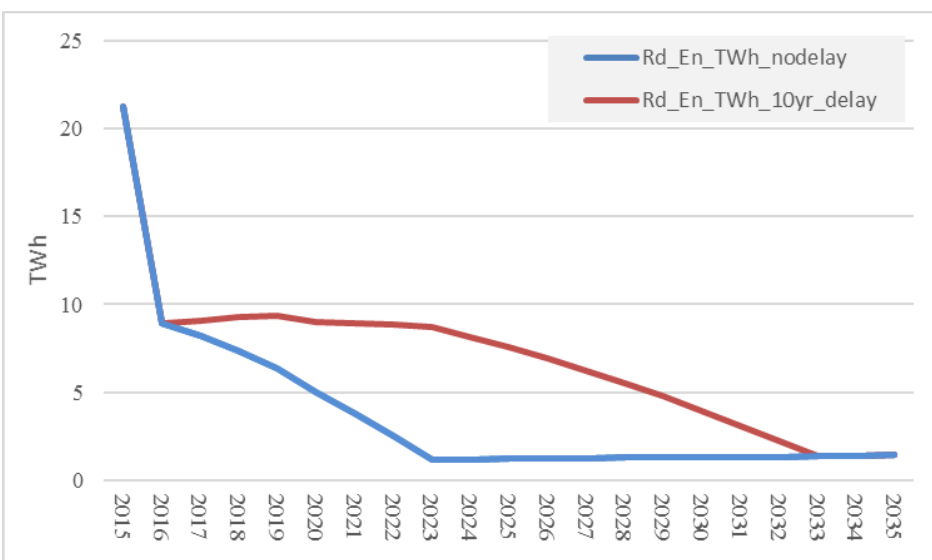

Figure 3.6 Model Scenario: Yearly $\mathbf{RdEn}_{\mathbf{cum}}$ as per two curves $\overline{\mathbf{RdEn}}_{\mathbf{delay}}$ and $\overline{\mathbf{RdEn}}_{\mathbf{nodelay}}$

3.2.4 Scenario for grid investments

It is already mentioned in section 2.2.3 that the future EEG plant development has been assumed in line with scenario-2035B of (NEP2030, 2017). As per the said scenario, the RE share in gross consumption is targeted at average 57% or an increase of 25.3% from status quo 31.7% RE share in 2015. Therefore, the yearly grid investments are determined as per methodology presented in sections 3.2.1 and 3.2.2 by setting RE target of 57%. Yearly investment, thus, come out as 4,393 Mio. Euros (T+D). Figure 3.7 shows that the cumulative transmission and distribution investments for period 2015-2035 comes out around 56.4 and 31.4 Bio. Euros respectively. The figure also shows the trend of cumulative investments needed against any targeted RE share increase. The trends show steeper increase as we target higher increase of RE share in gross consumption.

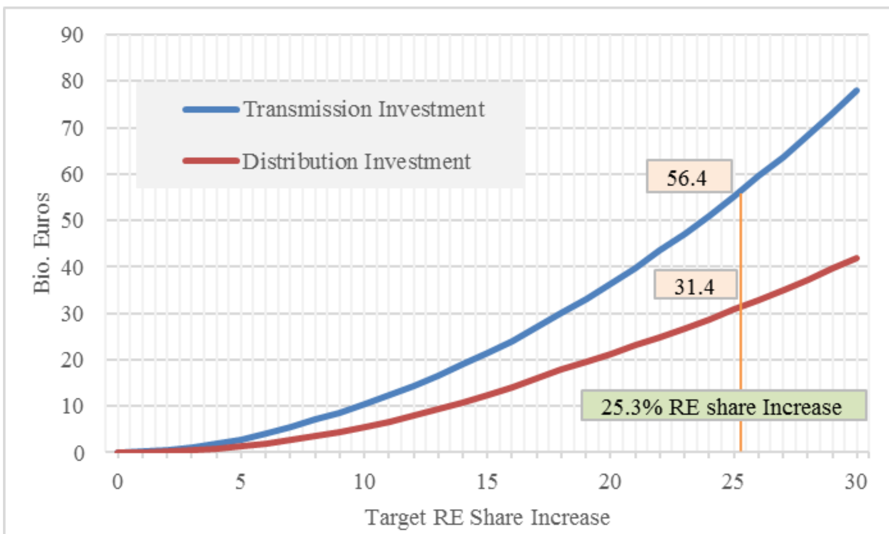

Figure 3.7 Model Scenario: RE target share in gross consumption by 2035 and required cumulative investments in Transmission and Distribution grid

3.3 Model Results and Validation

Figure 3.8 shows the model results for yearly transmission costs segregated into respective components. A validation has been done for the model results with the prediction done by (Hinz, et al., 2015) for 2024 transmission costs. The reference study assumed around 24.6 Bio. Euros of cumulative transmission expansion investments in period 2015-2024 which is comparable to this model's assumed cumulative transmission investment of 25.3 Bio. Euros for the same period. Model results indicate the transmission costs of 2024 as 6.3 Bio. Euros against the reference study's 6.4 Bio. Euros.

Figure 3.9 shows the model results for yearly distribution costs segregated into capital and non-capital parts. A validation has been done for the model results with the prediction done by

(Hinz, et al., 2014) for 2023 distribution costs. The reference study assumed approximately 13.8 Bio. Euros of cumulative distribution expansion investments in period 2015-2023 which is comparable to this model's assumed cumulative distribution investment of 12.5 Bio. Euros for the same period. Model results indicate the distribution costs of 2023 as 17.6 Bio. Euros against the reference study's 18.2 Bio. Euros.

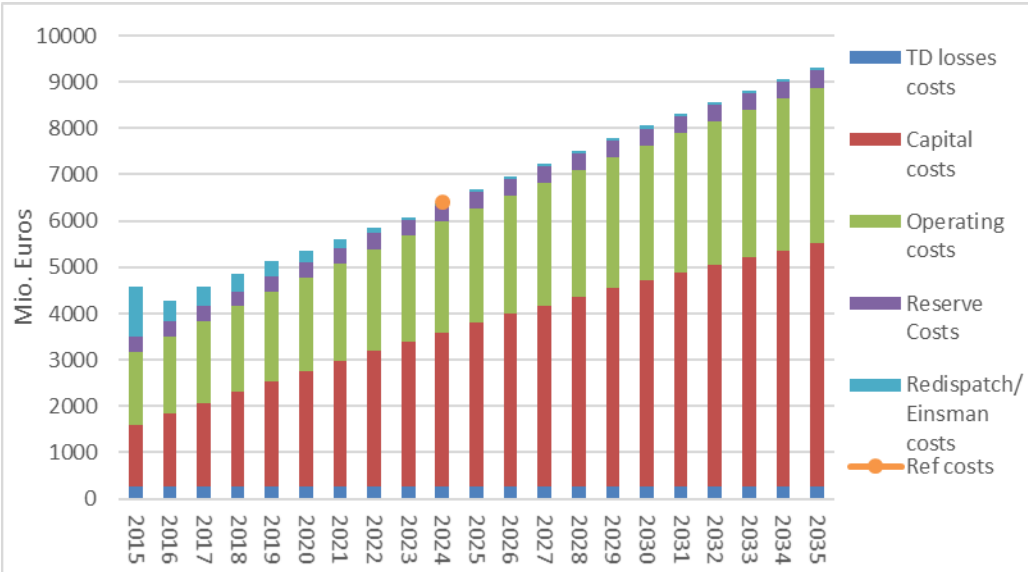

Figure 3.8 Model Results: Yearly transmission costs vs 2024 transmission costs predicted by (Hinz, et al., 2015)

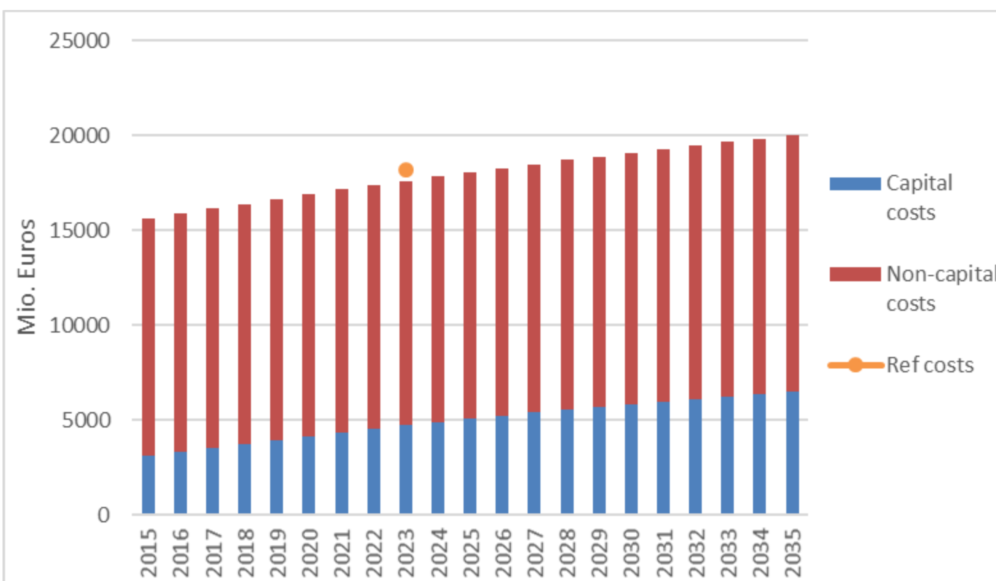

Figure 3.9 Model Results: Yearly distribution costs vs 2023 distribution costs predicted by (Hinz, et al., 2014)

Figure 3.10 shows the model results for average yearly network charges for household/SME and unprivileged industry consumers. It is observable that there is a consistent increase in charge levels from the year 2016 onwards. The network charges are slightly decreased from 2015 to 2016 due to low assumption taken about redispatch and Einsman costs. It can be observed that network charges increase steeply for household/SME consumers as compared to industrial consumers.

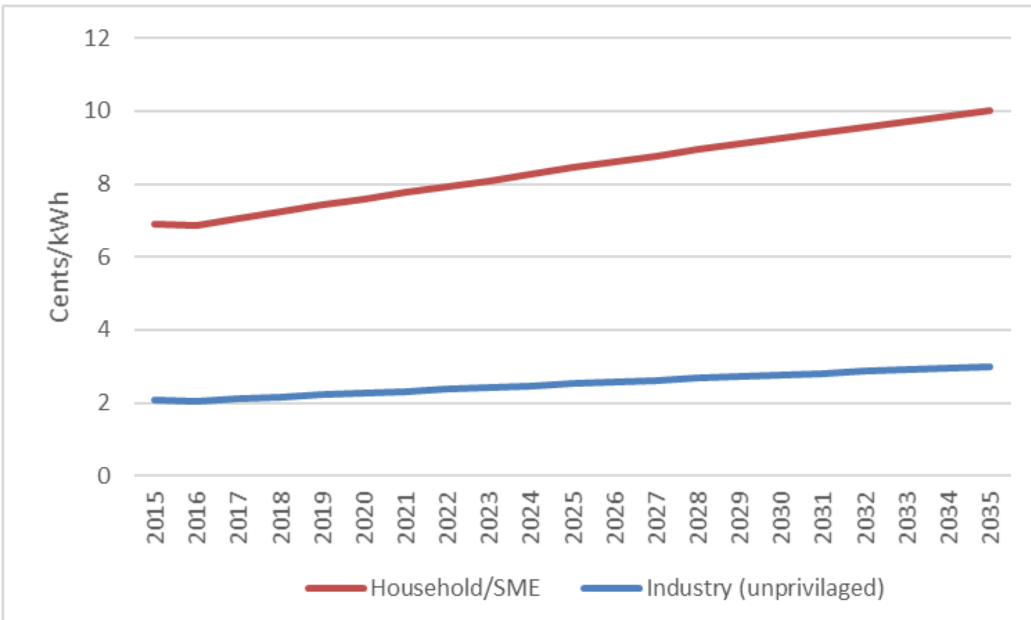

Figure 3.10 Model Results: Yearly average network charges for household/SME and industrial (unprivileged) consumers

Appendix Table B.1 lists the yearly transmission, distribution and services costs while Appendix Table B.2 presents the yearly average network charges for household/SME, unprivileged industrial consumers and StromNEV-19 surcharges against categories A, B and C. For OHU and AbLaV surcharges, as mentioned earlier in section 3.2, the associated total costs are assumed constant, at level as of 2017, for the future years under this study scope. OHU surcharge for categories A, B and C, thus, remains at levels of 0.058, 0.049 and 0.025 Cents/kWh respectively. AbLaV surcharge remains at level of 0.007 Cents/kWh.

4 KWKG SURCHARGE

4.1 Perspective

In Germany, since 1st April-2002 after coming into force of Combined Heat and Power Law or Kraft-Wärme-Kopplung Gesetz (KWKG), KWK plants are supported through an independent mechanism closely similar to EEG support system. Eligible KWK plants are generally offered an optional guaranteed selling tariff based on past quarter's average whole sale electricity price along with fixed bonuses per unit of electricity generated in KWK mode. Some payments are also directed to heat networks and storage providers. To find the specific portion of electricity generated in KWK mode, a KWK rating factor is determined for each plant through testing, that when multiplied to total heat produced gives the total KWK-electricity eligible for support. For smaller installations with no heat meters, all produced electricity is considered as KWK-electricity. Total costs of KWK support are recovered from consumers through a special surcharge known as KWKG surcharge. Like EEG surcharge, certain consumers are eligible to exemptions which is recovered by higher surcharge for unprivileged.

KWKG-2002 was very limited in its application and complexity. The support plan was offered only for certain specific years and for plant categories differentiated as old, recent old or modernized existing plants, new small plants below 2MW and fuel cell based plants. EEG supported KWK plants were not given any support under this framework. Self-consumption or use within private network e.g. within a building apartments was not eligible for support. The support was given in fixed cents per kWh of eligible portion of production and yearly total support was capped at 750Mio Euros.

KWKG was amended further in 2009 which led to inclusion of following important support scheme changes:

1. Support of existing and new high efficiency KWK plants below 50KW or fuel cell based plants were set to highest and was available for ten years.
2. For new KWK plants, high efficiency requirement was set in place along with support either for period of 6 years or till 30,000 full load hours. Modernized high efficiency plants were considered as new. Support was differentiated in capacity ranges like EEG.
3. Self-consumption was allowed a full support as the grid fed electricity.

Amendment of KWKG in 2012 brought a further change whereby along with modernized plants, retrofitted power plants above 2MW were eligible for support. Support period depended on costs related with such modernizations/retrofitting and was between 30,000 and 10,000 full load hours or as other option, if applicable, either 10 or 5 years.

Latest amendment of KWKG in 2016 brought along some fundamental changes and eligibility conditions. Main additions are:

1. Coal based KWK plants are no more supported and transition from coal to other fuel sources is encouraged through bonus over basic support. Bonus is also given to support emission obligations of new power plants.

2. Yearly support cap was doubled and eligible full load hours for below 50MW KWK plants was raised from 30,000 to 60,000 hours along with a general increase in support prices in context to lowering wholesale prices which affected revenues of KWK plants owing to their usual market price based agreements (Gailfuss, 2016). At the same time, eligibility for support of self-consumption was limited to either small plants below 100KW or plants feeding energy intensive enterprises.

3. Micro KWK plants can either get per kWh support or a onetime payment at start.

4. Unlike previous KWKG versions, KWKG-2016 set a future goal in absolute terms i.e. 110 and 120TWh KWK based electricity by 2020 and 2025 respectively.

5. A reduced KWKG surcharge for railway industry of maximum either 0.03 or 0.04 cents/kWh was previsioned. KWK-surcharge will also be reduced for industries in general in accordance to mechanism put in §64 of EEG (mentioned in 2.1.8) except that it must not be below 0.03 cents/kWh.

4.2 Model Description

As already mentioned, that there are several exemptions and reductions allowed to KWKG surcharge based on consumer category and nature. The developed model determines the base KWKG surcharge for unprivileged consumers for a target year by following formula:

$$KWK_{surcharge} = \frac{C_{KWK} \times f_{cost}}{Con \times f_{unprv}} \quad \textbf{(15)}$$

Where:

C_{KWK} = Total KWKG costs for target year

Con= Consumption in target year (assumed same for all years as of 2015)

f_{cost}= Factor to determine amount of C_{KWK} left after excluding revenues from privileged consumers

f_{unprv}=Factor to determine amount of Con left after excluding privileged consumption

(f_{cost} and f_{unprv} are determined as 0.978 and 0.540 using 2017 prognose (TSOs, 2016c) while *Con is set to 488TWh as of 2015. All parameters are assumed non-variable for calculations of future years)*

Removing cost and consumptions factors from equation (15) and using 80% or 85 % reductions, KWK surcharge for 20% and 15% categories of privileged industries (mentioned in 2.1.8) can be determined respectively. C_{KWK} for a target year is a sum of three main elements provisioned in KWKG-2016:

$$C_{KWK} = C_{support} + C_{onetimepayment} + C_{net/storage} \tag{16}$$

Where:

$C_{support}$ = *Costs owing to payment in cents/kWh to KWK generation*

$C_{onetimepayment}$= *Costs owing to onetime payment option for less than 2KW KWK plants*

$C_{net/storage}$= *Costs owing to payments to heat networks and heat storage systems*

Two cost components, $C_{onetimepayment}$ and $C_{net/storage}$, made less than 10% of total KWKG costs in recent several years. They are assumed at the levels as of 2016 as per (TSOs, 2016c). $C_{support}$ is calculated through detailed modeling. $C_{support}$ is the total costs accounted for paying support in cents/kWh to eligible KWK plants for KWK-generation as per terms and conditions of KWKG applicable in the period when the plant got commissioned. To estimate these costs, it is therefore essential to handle separately the different KWKG regimes of 2009, 2012 and 2016. Based on limited data availability and relative size of KWKG surcharge component in overall electricity costs, a simple approach is adopted whereby $C_{support}$ is estimated for the target year by following formula:

$$C_{support} = \sum_{C1,C2,C3,M} (Cap_{2009} \times P_{2009} + Cap_{2012} \times P_{2012} + Cap_{2016} \times P_{2016}) \times CF \tag{17}$$

Where:

M, C1, C2, C3= plant categories explained below

Cap= Cumulative capacity per category till target year falling under KWKG-2009/2012/2016

CF= Capacity factor per category

P= Average per unit support payments per category falling under KWKG-2009/2012/2016

For calculating $Cap_{2009,2012,2016}$, a data set is taken from (Öko-Institut, 2015), shown in Appendix Table C.1**,** which contained the yearly additional capacities in MWs that came under the KWKG support from 2009 till 2014. The data set is modified into four categories. Three categories are for new, replaced or retrofitted KWK plants based on capacity sizes i.e. C3 for less than 50KW, C2 for 50-2000KW and C1 for above 2MW. Category-M is for modernized plant capacities falling in all size ranges. From the dataset, expiring capacities and corresponding years are determined based on incoming capacity timelines and an average support period estimate per category. $Cap_{2009,2012,2016}$ is determined by summing the yearly incoming and expiring capacities per year and later accumulating it over the years. KWKG support expires for the plants that complete their respective support periods allowed in KWKG framework. Average support periods are determined in number of years from the study of respective KWKG frameworks and are listed in Table 4.1.

Table 4.1 Model Parameters: Average support periods (years) for KWK plant categories

Framework	Cat-M*	Cat-C1**	Cat-C2	Cat-C3
KWKG2009	6	6	6	10
KWKG2012	8	11	10	10
KWKG2016	8	11	10	20

** Roughly 75% of yearly modernizations belonged to above 50% cost category (Öko-Institut, 2015). The 50% cost category, as per KWKG, get double support period length then below 50% cost category. The average support period is determined by weighting support periods of each KWKG accordingly.*

***In various cases where support period length is not given in years but in total supportable full load hours in respective KWKG regimes, average yearly full load hours for C1-plants are used, determined by averaging industrial and general supply's yearly average full load hours weighted by their share in overall KWK generation in 2014 using data available in (Öko-Institut, 2015).*

To extend the above-mentioned data set of incoming capacity additions from 2014 onwards till 2035, a brief context is to be considered. (Gailfuss, 2016) said that although the KWKG-2016 increased the support amount per kWh, which reached up to 83% in maximum cases, it was done in context of falling whole sale prices. Furthermore, the self-consumption will now be treated with reduced support. Therefore, it can be implied that the trends of yearly capacity additions under KWKG framework will continue without significant change. Furthermore, KWKG-2016 set a target of reaching 120TWh in 2025 while in 2014, 98TWh were produced from KWK capacity (Öko-Institut, 2015). This gives a roughly 22.4% growth margin in generation, which if applied in same extent on capacity, the growth margin would come out to be around 7GW, assuming total KWK capacity in 2014 as 32GW (Öko-Institut, 2015). Therefore, it can be implied that KWKG law will facilitate the growth in KWK installations to meet at least 7GW of additions and maintain it. It must also be noted that the KWK generation remained nearly stagnant around 97 to 100TWh from 2010 to 2014 (Öko-Institut, 2015). In addition, an important aspect is that if the yearly support cap of 1.5 bio euros is crossed, then necessary support reductions would be applied to limit the support levels. In the stated context, the yearly capacity additions for future years are assumed to continue as per previous increasing trends until the total supported capacity under KWKG framework ($Cap_{2009/2012/2016}$ collectively) reach around 7GW while the $C_{support}$ remains under limit of yearly support cap. Onwards the new additions are so designed that the total supported capacity should remain locked around 7GW, assuming that the capacities, whose KWKG support expires, compensate fully the general KWK capacities expiring operationally. This means that outside KWKG supported new plant portfolio, the KWK capacities remain at the same level as of 2014.

Figure 4.1shows the input scenario of category wise yearly accumulated capacities (regardless of individual KWKG frameworks) along with the actual new capacities obtained by summing categories C1, C2 and C3. It can be observed that installed capacity under all categories, except M, become stagnant after 2018 upon reaching the newly supported total capacity of 7000MW. Installed capacities under category M saturates after 2020 as the further increase would cause C_{KWK} to cross yearly cap.

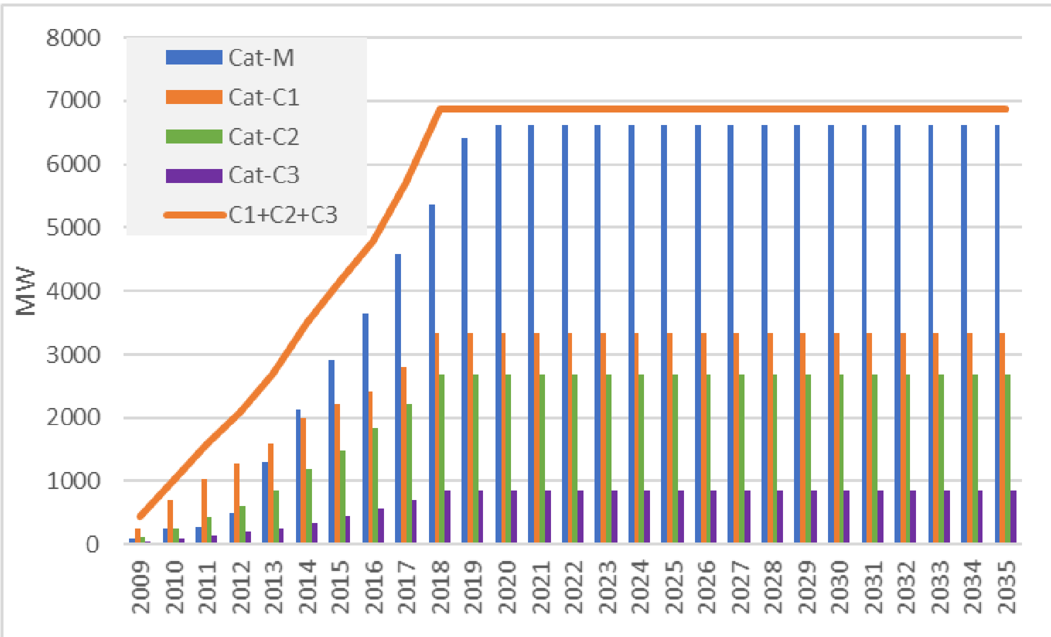

Figure 4.1 Model Scenario: Yearly accumulated capacities for categories M, C1, C2, C3 and new KWK capacity obtained from summing C1, C2 and C3 results.

The parameters P and CF, used in equation (17), are plant dependent. However, due to absence of plant based dataset, average values are estimated. CF is determined from accumulated installed KWKG capacity as described earlier and KWKG eligible generation taken from 'Jahresabrechnung' report of year 2014 (TSOs, 2015) and is listed in Table 4.2. Figure 4.2 shows the actual variations of capacity factor over the period of 2013-2015. It can be observed that setting the capacity factors at the values observed in 2015 is roughly justified since the variation over the past two years are not very significant. The parameter set P which feature the average payments in cents/kWh to KWK plants per category and per KWKG regime is also determined using 'Jahresabrechnung' reports and is shown in Table 4.2. For KWKG-2009 & 2012, Jahresabrechnung reports of 2011 (TSOs, 2012) and 2014 (TSOs, 2015) are used respectively. These years are chosen in such a manner that tail effects of KWKG 2002 regime in 2009 & 2010 and transition effects of KWKG2009 and KWKG2012 in year 2012 can be avoided. Years 2013 and 2014 are also skipped since year 2015 provides the latest figures. For calculating average P values per category for KWKG2012 using year 2015, total yearly payments are first subtracted with payments owing to plants falling under

KWKG2009. The flexibility of choosing a specific year is justified since unlike EEG framework, remuneration rates do not change under KWKG frameworks. P values for KWKG2016 are not possible to estimate in same fashion since no data is yet available. They are set at 50% increase from past values based on a broad approximation of results obtained by comparing support sets of C1, C2 and C3 classes for KWKG 2016 & 2012 using plant capacities in range of 1KW-50MW.

Table 4.2 Model Parameters: P(cents/kWh) and CF for KWK plants

Parameter	Cat-M	Cat-C1	Cat-C2	Cat-C3
P_{2009}	1.68	1.59	2.45	5.11
P_{2012}	2.20	2.28	3.46	5.41
P_{2016}	3.3	3.42	5.19	8.11
CF	0.36	0.29	0.4	0.51

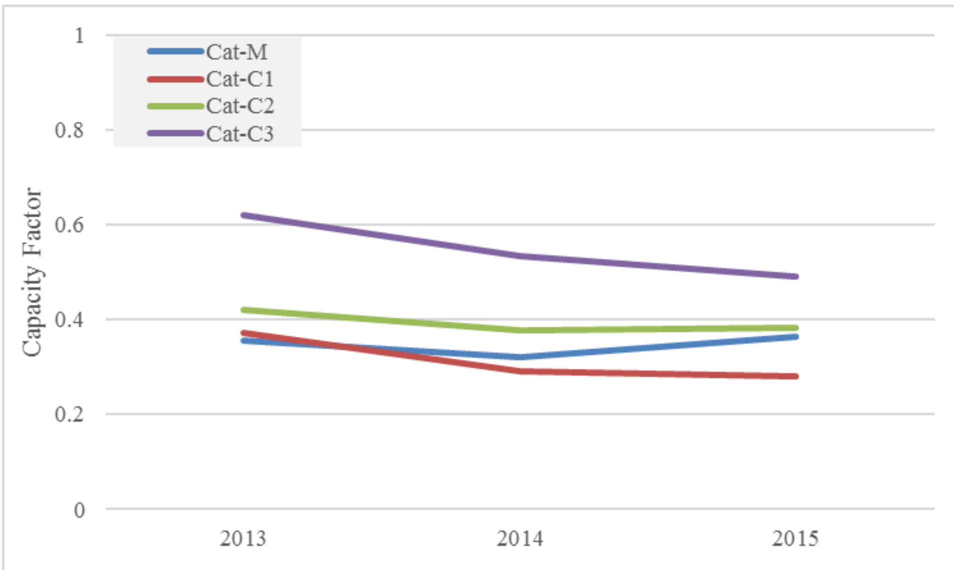

Figure 4.2 Variation of KWK capacity factors over 2013-2015

4.3 Model Results and Validation

Figure 4.3 shows the results of the model calculation of yearly KWK support costs occurring per plant category. The model calculations follow in general the trends seen in past years. The costs prediction of 2017 provided by (TSOs, 2016c) aligns well with the model results. Figure 4.4 gives the future trend of base KWKG surcharge for unprivileged consumers as per KWKG-2016 mechanism, mentioned by equation (15). Appendix Table C.2, provides the aggregate yearly installed capacities, generation, costs and KWKG surcharge values as resulted from model calculations.

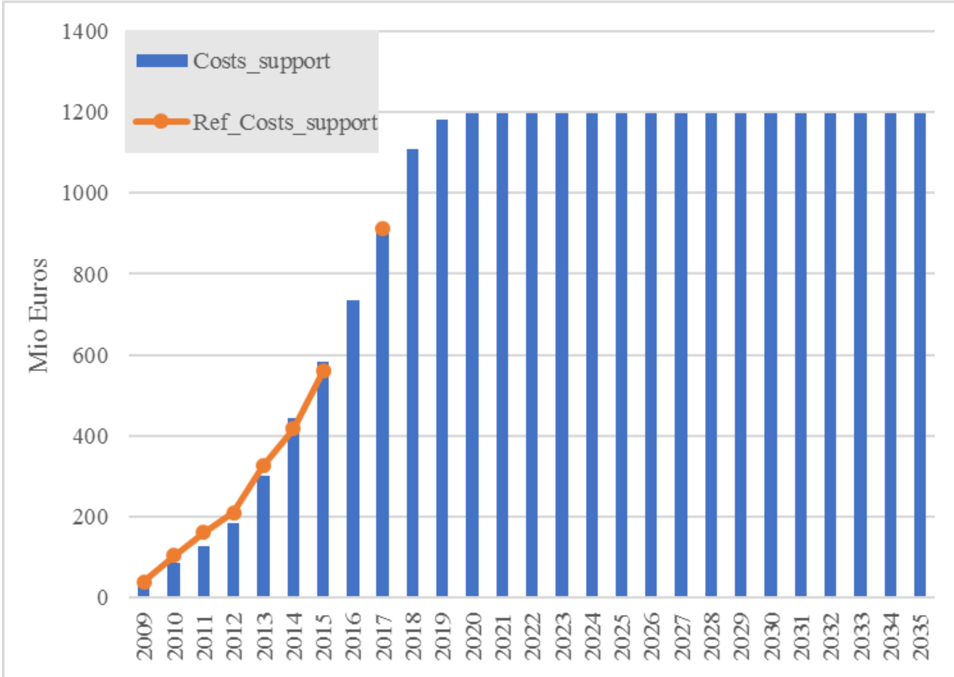

Figure 4.3 Model Results: Yearly KWK support costs plotted along with known support costs as per Jahresabrechnungen reports of 2009-2015 and 2017 prognose (TSOs, 2016c).

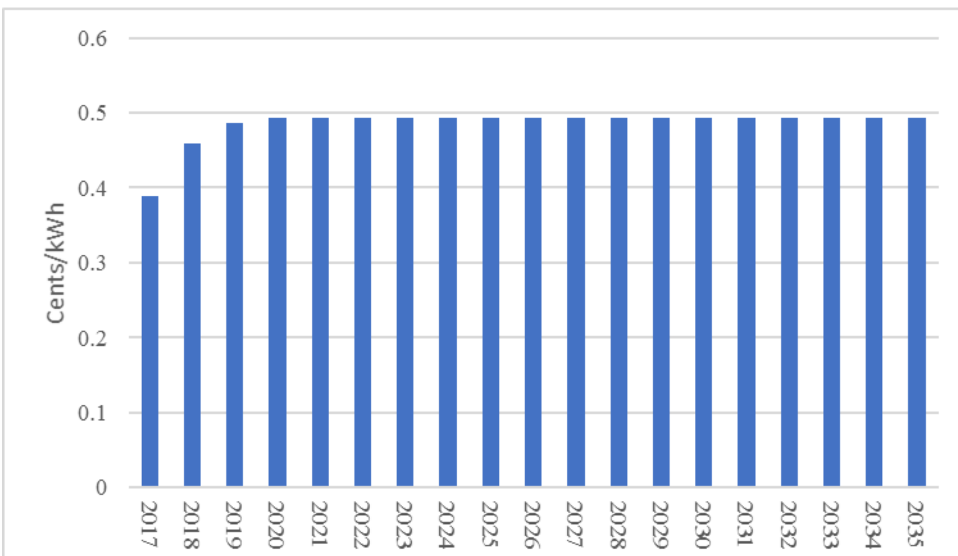

Figure 4.4 Model Results: Yearly base KWK surcharge for unprivileged consumers as per KWKG-2016 mechanism

5 PRICE DEVELOPMENT TILL 2035

Results from the prior described python models are segregated as per applicable regulations, across three consumption classes defined in next sections along with model results. In the yearly results, the components; billing/metering & operation fees, concession fees, electricity duty and supply costs are assumed to remain at same level as of 2015, shown in Table 1.2. The results are presented excluding VAT component.

5.1 Household Consumption

Households are connected to the grid at low voltage (0.4KV). Households are metered on non-interval basis using standard load profile and are not considered for any exemptions in network charges as discussed in 3.1.6. Households generally consume less than 10,000kWh which makes them in-eligible to any reductions in surcharges or electricity duty. Figure 5.1 shows the model results for the yearly average electricity price development of household customers. The results show that household would face an increase of roughly 3.37 Cents/kWh in electricity prices till 2028 mainly due to rising EEG surcharge and network charges. After 2028, the falling EEG surcharge levels would provide some relief but the prices would still be higher than 2015 due to consistently increasing network charges.

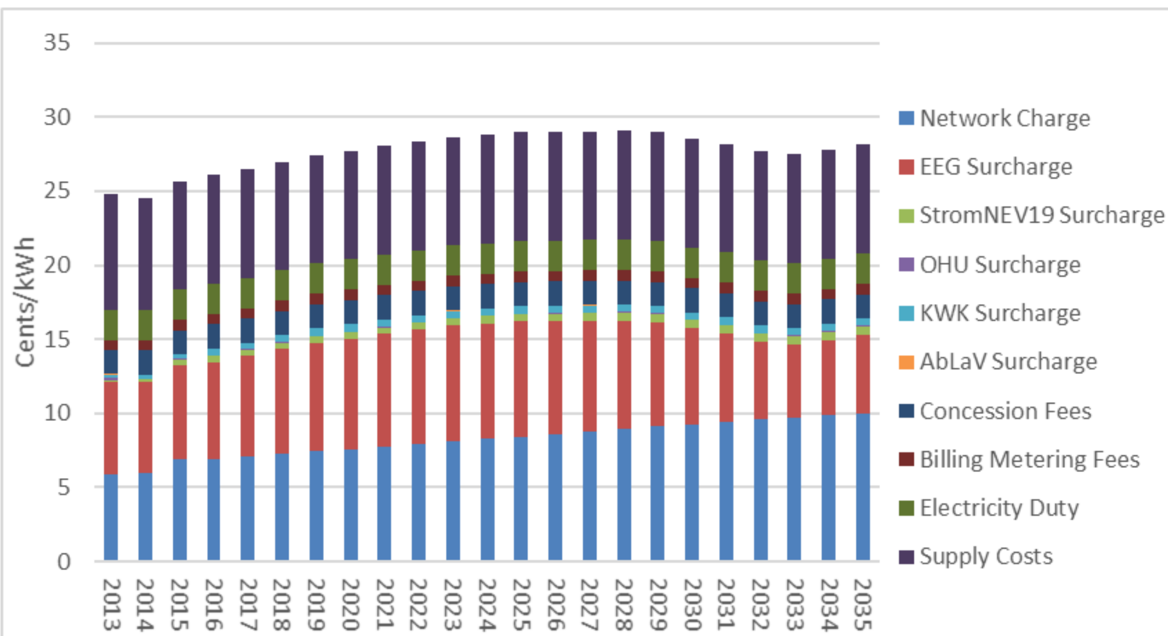

Figure 5.1 Yearly average electricity price development for household customers from model calculations (Values for 2013,2014 from BNetzA)

5.2 Unprivileged Industrial Consumption

An unprivileged industry would be the one which is not linked to rail system and which is connected to high or medium voltage grid system (110KV or 35KV). The yearly consumption for such industry would generally lie above 24GWh as per (BNetzA, 2016a), however, as per category scope only the costs of the first GWh consumption are considered. Therefore, no reductions in EEG, KWKG, StromNEV-19 and OHU Surcharges are applicable. Owing to connection to high voltage network, such industry enjoys significantly reduced network charges and concession fees. However, it is assumed that the industry does not qualify for any reductions in network charges owing to its asymmetric load profile. Due to high consumption volumes, the billing/metering costs and supply costs are also relatively less for industries. Figure 5.2 shows the yearly price development for this consumption category. The results show an increase of roughly 2.17 Cents/kWh in electricity prices till 2024.

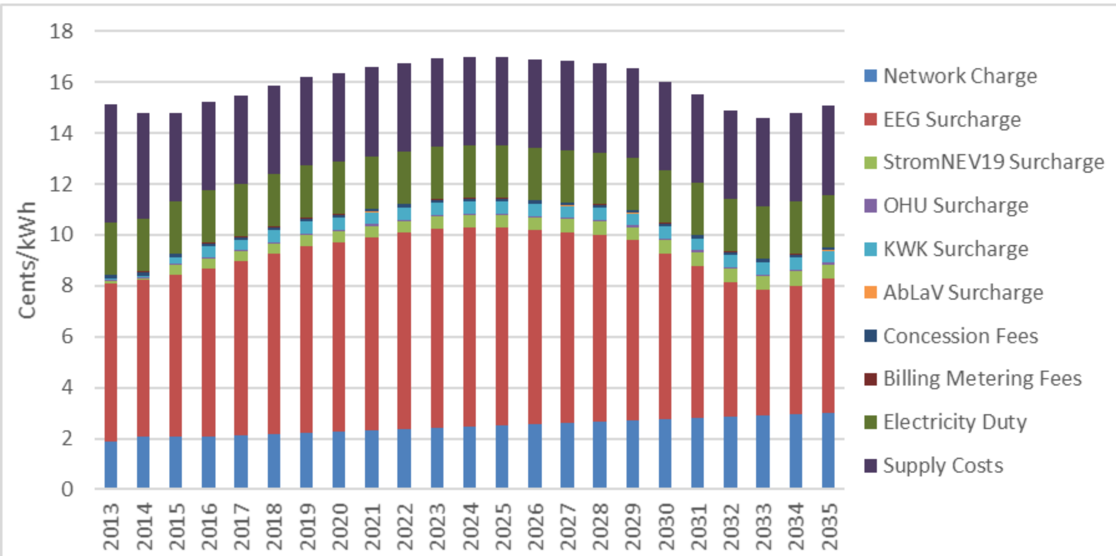

Figure 5.2 Yearly average electricity price development for unprivileged industrial consumption from model calculations (Values for 2013,2014 from BNetzA)

5.3 Privileged Industrial Consumption

For privileged consumption class, an industrial load similar to one described in previous section can be considered with assumption that industry's electricity cost intensity, described in section 2.1.8, is at least 20% and consumption class considered is above 1GWh so that it is eligible for 85% reduction in EEG and KWKG surcharge as per §64-EEG-2017 and qualify for category C rate in regard to application of StromNEV-19 and OHU surcharge. It is also assumed that the industry has asymmetric load with full load hours above 8000 hours so that it gets only 10% of regular network charges. It is further assumed that the said consumption class relates to those manufacturing processes which are exempt from electricity duty. This legal provision is in place to safeguard international competitiveness of German industry. Figure 5.3 shows the yearly price development for said consumption category. The results show that said consumption class would face a minute increase of roughly 0.24 cents/kWh in electricity prices till 2024.

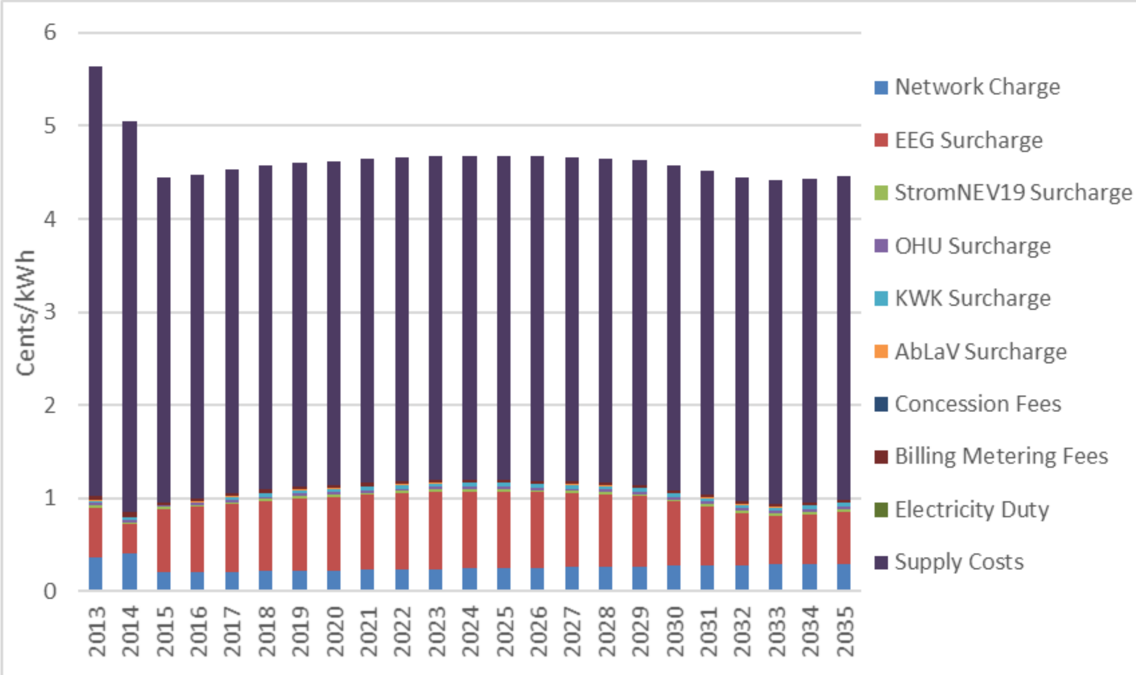

Figure 5.3 Yearly average electricity price development for privileged industrial consumption from model calculations (Values for 2013,2014 from BNetzA)

Figure 5.4 depicts the five-yearly electricity retail price development across three consumption classes discussed above. It can be observed that the relative increase of component prices, resulted from model predications, is highest for the household consumers and there is hardly any such effect observable for privileged industrial consumption.

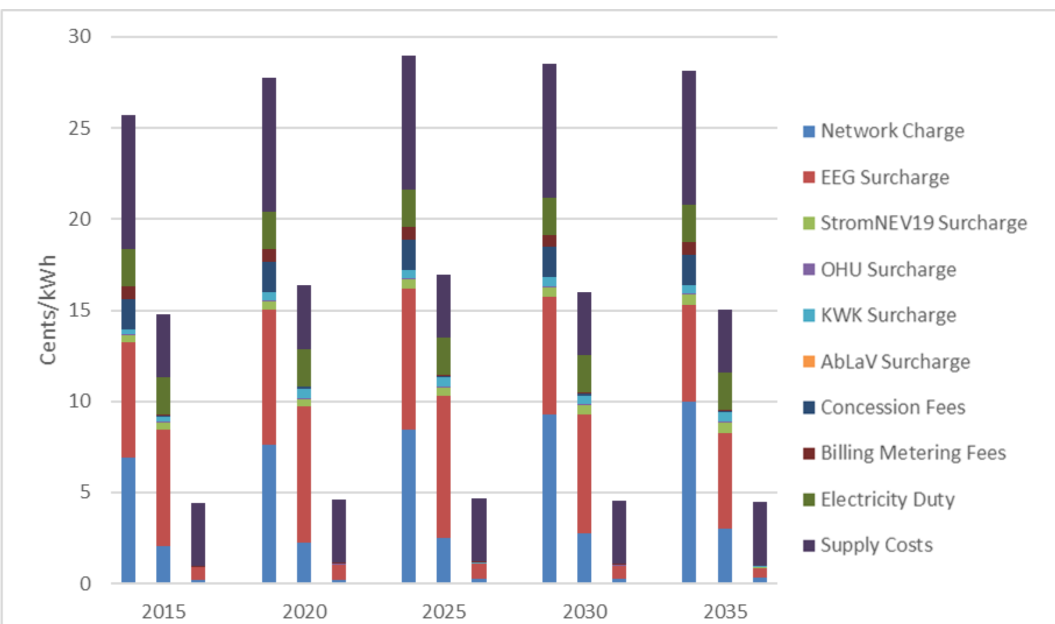

Figure 5.4 Five yearly electricity price development for three consumption classes; Households (Left), unprivileged industry (middle) and privileged industry (right)

6 CONCLUSION & OUTLOOK

Two important aspects are clearly visible from model results. Firstly, the EEG energy generation will rise significantly till 2035, which would make roughly 60% increase from status quo level of 2015. Secondly, the retail electricity prices are still expected to rise owing to increasing EEG surcharge and network charges. The integration of fast growing renewable energy generation and rising retail prices within Germany, are already the subjects of intense discussion on diverse social, political, economic and academic forums. The next two sub sections give a brief outlook on these subjects in light of several consulted literatures. The last subsection presents the existing model research gaps and outlook of the future research possibilities to enhance the developed python models.

6.1 Integration of RE generation

Fast RE growth has already revolutionized the German electricity industry. RE growth has made whole sale electricity prices to fall considerably not only within Germany but also in neighboring countries. It has noticeably contributed towards reducing country’s dependency on imported fuels. Vast spread decentralized solar generation has brought a strong prosumer culture at the end user side of the electricity supply chain. The efforts for smart grids and digitalization make more sense now and are happening with clear directions. The variable RE generators are participating in reserve markets using spatial diversity benefits, thus, unshackling the core limitation of variability of individual RE installations through cooperation. On the other hand, RE growth has brought grid development challenges to cope with redispatch and Einsman costs. Electricity markets are facing critical challenge to maintain long term supply security nationally and on European level.

Integration of RE generation is not a solo pursuit of Germany. It’s a collective European ambition as well. (Agora, 2015) states that 70% of EU’s new electricity installations of 2013 were RE based. The author illustrated Germany’s standings in the 2020-RE targets across EU member states, shown in Figure 6.1. The figure shows clearly that Germany’s RE ambition aligns well into EU context. In such environments, the author states that the close cooperation of cross border electric grids can improve the supply security in concern to rising RE generation. As per new methods developed by Pentalateral Energy Forum for joint assessment of resource adequacy, the author states that joint peak load of EU neighbors comes out 10GW lesser than the sum of individual country load peaks. However, this close cooperation has yet to meet many challenges.

(Stefes & Hagor, 2016) states that the need for grid development in Germany had already been identified by German Energy Agency (Dena) in 2005. However, the political, financial and administrative limitations delayed the process. In the meantime, cross border EU interconnections helped meeting the north based high generation and south based high consumption of Germany. In recent years, grid congestion from German north to south has caused electricity produced from RE installations of north, to take indirect paths, also called loop flows, through east European countries like Poland, Czech, Slovakia and Hungary (Schlandt, 2015). The loop flows compromised the N-1 grid security criteria of the affected countries. Complains from these countries led to the installation of physical power controlling devices at some grid points which made it even more important to pursue grid development to cope with expected high growth of RE in north, especially offshore wind.

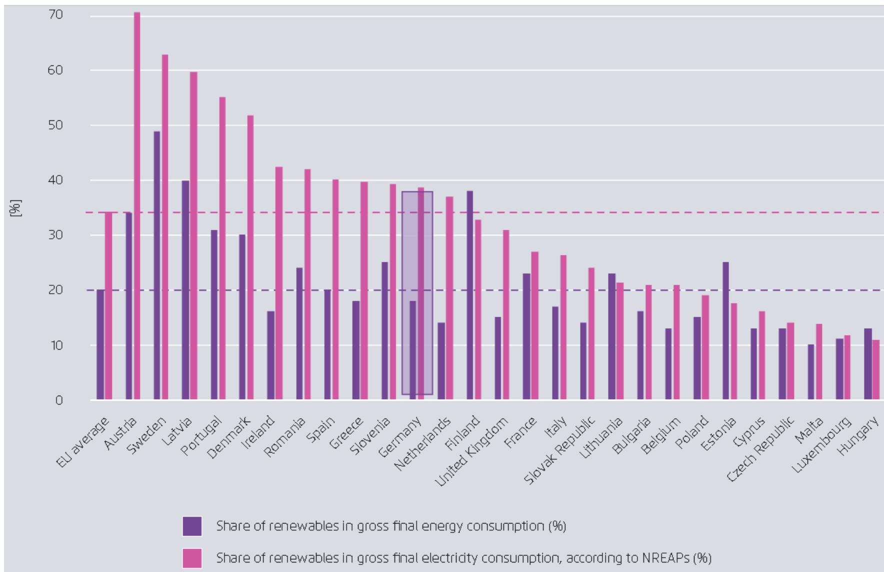

Figure 6.1 EU 2020-RE targets [Taken from (Agora, 2015)]

Rapidly increasing RE generation is also a matter of concern as present electricity markets provide insufficient price signals and incentives to encourage flexible but expensive peak power plants and baseload generators, that lack flexibility to tune to cheap variable RE feed in, to stay in operation. For future, Germany is favoring for a market only approach supported by strategic reserves, however, other European countries favor capacity markets as evident from the recent Winter Package from EU Commission. If Germany, would take a solo path, it may end up with disadvantages on national and EU level as investigated by (Statnett, 2015). The author states that such a path would lead Germany to depend more on electricity imports at the time of low RE generation. This would also lead neighboring countries to focus strongly on capacity security due to lack of any investment signals from Germany.

By far, Germany has been very successful in bringing the positive effects of Energiewende in electricity sector. However, with the expanded RE portfolio, the need for sector coupling has become much more important. Electric vehicles, electricity storage, demand side management, power to heat etc. are the options that must be promoted to cope with future periods of peak or no RE generation when the backup would be either insufficient or too expensive to afford.

6.2 Rising retail electricity prices

Rising retail electricity prices have already been a big concern for Germany despite the benefits of RE energy sales at the wholesale market level. Apart from the rising EEG costs, regional problems with network charges are also present. Consumers of DSOs that are facing high decentralized RE growth, are paying for increased costs owing to avoided network charges that relieve, in turn, the EEG surcharge levels for all country. Region based network charges are rising for less dense German north due to grid expansions for offshore RE installations and general reinforcements to cope with decentralized RE generation.

Rising EEG surcharge levels have already changed the course of EEG when in 2012, the solar cap was introduced which was later extended to wind and biomass as well. In context to developing EU context and to promote cost efficiency, auction system was also introduced in EEG-2017. However, the EEG mechanism has not remained simple anymore and there is a strong counter pulling argument. Controlling the cost efficiency may contradict with the fundamental Energiewende dimension of diversified ownership. (Stefes & Hagor, 2016) suggests that the introduction of auction system may reverse the trend of decentralized RE plant ownerships back to big investors as they can easily outcompete the former in energy costs. It was due to such concerns, EEG-2017 provisioned no auctions for below 750 KW solar and wind plants and below 150KW biomass plants.

Exemptions allowed in EEG mechanism is also a great social debate in Germany. (Agora, 2015) states that although the household electricity retail prices in Germany are relatively high, the average household consumption is quiet small which ends up in same energy expenses as the households of comparable industrialized countries. However, (Stefes & Hagor, 2016) states that Energiewende is socially unbalanced, which distributes income from bottom to middle and top class. The author argues that industries enjoy EEG exemptions and the lower wholesale electricity prices due to Energiewende. The home owners and farmers pay higher electricity bills but they also benefit from own RE generation. Those who live in apartments face the high electricity costs but counter some effects through efficient use of electricity. However, the lowest income class may not even utilize the efficiency measures due to insufficient savings to invest. (Ecofys, 2015) states that energy intense German industries, that receive full privileges on surcharges/electricity duty and reduced grid fees, get competitive electricity rates. Without such privileges, the German households and small businesses may enjoy slightly reduced EEG surcharges (around 1.6 cents as of 2014). However, lack of privileges would have negative macroeconomic effects along with around 104,000 lost jobs, estimated by the authors.

6.3 Research gaps and future research direction

During the development of the models for EEG, KWKG, StromNEV-19 surcharges and network charges, some key research gaps were either deliberately simplified or could not be modelled due to time constraints. The brief description of these research gaps is listed below:

1. ***All Models***: A constant yearly consumption has been assumed for future years. Yearly consumption depends on several factors such as economic conditions, efficiency incentives, demographic changes etc. A research can be conducted to develop a more realistic consumption scenario. Furthermore, the factors used in equations (1), (8), (9), (10) and (15) depend on yearly consumption trends between privileged and unprivileged consumers. At present these factors are simply assumed based on forecast results from (TSOs, 2016a), (Hinz, et al., 2015) and (TSOs, 2016c). In future, the model can be enhanced to model privileged and unprivileged consumptions and cost distributions.

2. ***EEG Model:*** Future development of EEG average tariffs was estimated using (Oeko-Institut, 2016) with simple linear interpolation. In practice, these tariffs depend on several aspects such as learning curve effects, technical improvements, social acceptance etc. A research can be conducted to develop a more realistic future tariff scenario by incorporating above stated aspects.

3. ***EEG Model:*** To get rid of underestimation of costs for wind onshore plants owing to assumption of the same minimum initial tariff period of 5 years, an average increase of 9 years was added to all onshore plants, based on weighted average initial tariff periods of country wide wind plants on lands with varying wind resource potentials, as described in 2.2.2. This approach is an oversimplification of EEG costs for the wind onshore plants. In future, model can be enhanced in such a fashion that the wind onshore plants available in the plant database (Energymap, 2017) can be given individual initial tariff periods based on their geographical parameters i.e. Nuts3 or Merra2 ids.

4. ***EEG Model:*** At present a single cleavage strategy is assumed for distributing market factors among smaller and bigger plants. In future, model can be enhanced to feature three or more plant groupings with distinct direct marketing habits as evident from illustrations provided by (Götz, et al., 2013).

5. ***Network Charges Model:*** The relation between needed grid investments and targeted RE shares was estimated using two data points each of distribution and transmission sectors. Although, the original target was to collect at least four data points for each sector to achieve higher accuracy of predictions, author’s limited ability with literature

research in German language, hindered the progress and confined the research to two points each only. In future, this aspect can be enhanced relatively easily by further research of additional data points.

6. ***Network Charges Model:*** The model does not incorporate the detailed modeling of avoided network charges. The sharp rise of costs incurred by DSOs in respect of avoided network charges, in recent past, has already sparked huge debate in academic researches. In future, the model can be enhanced to incorporate modeling of costs of avoided network charges. It will enable the model users to conduct researches on better policy options for handling such costs.

7. ***KWKG Model:*** The support rates per kWh for KWK generation as per KWKG-2016 was assumed as 150% of KWKG-2012 rates based on a broad approximation of results obtained by comparing support sets of C1, C2 and C3 classes for KWKG 2016 & 2012 using plant capacities in range of 1KW-50MW. This approximation was adopted due to absence of data i.e. the Jahresabrechnung report-2016 for KWKG yearly accounts has not been yet published. Upon the availability of the said and additional data, the average support rates can be appropriately researched and incorporated.

As already shortly discussed in the subsection 6.2 that the rising retail electricity prices are sparking strong social concerns in Germany. Model results for EEG surcharge and network charges predict further increase in prices in future which are significant enough to be considered. Consequently, these results drive the motivation for a possible research into analyzing effects of opting innovative policy options that would dampen the increasing prices partially. However, such researches can only be realistically conducted if further models are integrated with the developed model. These further models may include the modeling of future developments of wholesale electricity prices, yearly supply margins, yearly consumption, feedback effects of electricity prices on consumption behaviors etc.

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Appendix A. Data relating to EEG Model

Appendix Table A.1 Model Scenario: Yearly EEG capacity (GWs) per technology

Year	Biomass	Geothermal	Mine/Sewage /Landfill Gas	Solar	Water	Wind Offshore	Wind Onshore
2015	7.14	0.03	0.64	37.27	1.65	1.68	38.59
2016	7.15	0.03	0.64	37.40	1.65	3.65	39.71
2017	7.15	0.03	0.64	39.58	1.76	4.91	41.04
2018	7.15	0.03	0.64	41.76	1.88	6.17	42.38
2019	7.15	0.04	0.64	43.94	2.00	7.42	43.71
2020	6.89	0.03	0.46	46.11	2.12	8.68	41.52
2021	6.70	0.04	0.40	48.23	2.23	9.94	41.14
2022	6.71	0.04	0.42	50.15	2.42	10.55	42.64
2023	6.74	0.04	0.39	52.06	2.60	11.17	43.72
2024	6.69	0.04	0.36	53.93	2.79	11.78	45.14
2025	6.37	0.04	0.34	55.29	2.97	12.39	47.31
2026	5.88	0.04	0.39	56.39	3.16	13.01	49.55
2027	5.59	0.04	0.39	59.23	3.34	13.62	50.33
2028	5.42	0.04	0.39	61.64	3.53	14.24	51.54
2029	5.56	0.04	0.39	63.34	3.70	14.85	53.56
2030	5.65	0.03	0.39	62.62	3.40	15.43	53.79
2031	5.58	0.03	0.39	58.63	3.22	16.00	55.20
2032	4.97	0.04	0.38	57.71	3.21	16.81	57.02
2033	5.11	0.03	0.38	58.06	3.39	17.65	58.32
2034	5.28	0.02	0.39	62.15	3.60	18.22	58.95
2035	5.49	0.02	0.39	68.16	3.88	18.08	58.08

Appendix Table A.2 Model Scenario: Yearly average default tariff (Cents/kWh) per technology

Year	Solar	Wind Onshore	Wind Offshore	Biomass	Mine/Sewage/ Landfill Gas	Geothermal	Water
2016	11.00	8.90	19.40	17.70	8.20	25.20	11.70
2017	10.92	8.71	18.83	17.51	8.18	24.58	11.64
2018	10.84	8.52	18.27	17.32	8.16	23.96	11.59
2019	10.77	8.33	17.70	17.13	8.13	23.33	11.53
2020	10.69	8.14	17.13	16.94	8.11	22.71	11.48
2021	10.61	7.96	16.57	16.76	8.09	22.09	11.42
2022	10.53	7.77	16.00	16.57	8.07	21.47	11.37
2023	10.46	7.58	15.43	16.38	8.04	20.84	11.31
2024	10.38	7.39	14.87	16.19	8.02	20.22	11.26
2025	10.30	7.20	14.30	16.00	8.00	19.60	11.20
2026	10.11	7.01	13.96	15.85	8.00	19.16	11.14
2027	9.92	6.82	13.62	15.70	8.00	18.72	11.08
2028	9.73	6.63	13.28	15.55	8.00	18.28	11.02
2029	9.54	6.44	12.94	15.40	8.00	17.84	10.96
2030	9.35	6.25	12.60	15.25	8.00	17.40	10.90
2031	9.16	6.06	12.26	15.10	8.00	16.96	10.84
2032	8.97	5.87	11.92	14.95	8.00	16.52	10.78
2033	8.78	5.68	11.58	14.80	8.00	16.08	10.72
2034	8.59	5.49	11.24	14.65	8.00	15.64	10.66
2035	8.40	5.30	10.90	14.50	8.00	15.20	10.60

Appendix Table A.3 Model Scenario: Yearly EEG generation (TWh) per technology

Year	Biomass	Geothermal	Mine/Sewage /Landfill Gas	Solar	Water	Wind Offshore	Wind Onshore
2015	40.62	0.13	1.42	34.88	5.28	12.56	70.10
2016	40.63	0.13	1.42	35.95	5.48	17.16	71.75
2017	40.63	0.14	1.42	37.95	5.86	21.53	73.88
2018	40.64	0.14	1.42	40.00	6.20	26.74	75.98
2019	40.64	0.14	1.42	42.04	6.59	30.92	77.99
2020	38.74	0.14	0.98	44.02	6.96	35.70	72.28
2021	38.27	0.14	0.91	45.91	7.42	39.26	73.19
2022	38.57	0.14	0.94	47.68	8.02	41.35	74.32
2023	38.64	0.15	0.85	49.47	8.64	43.71	75.91
2024	37.69	0.15	0.80	51.00	9.23	45.85	77.69
2025	36.03	0.15	0.84	52.19	9.85	48.28	81.35
2026	33.80	0.15	0.87	53.90	10.41	50.62	82.68
2027	32.07	0.15	0.87	56.65	11.02	52.84	83.58
2028	31.77	0.15	0.87	58.59	11.58	54.77	85.41
2029	32.62	0.14	0.87	59.68	11.91	57.31	86.59
2030	32.93	0.13	0.87	56.83	10.85	59.40	87.83
2031	31.76	0.14	0.86	56.17	10.38	61.60	90.53
2032	28.95	0.14	0.85	54.03	10.68	64.57	92.38
2033	30.00	0.07	0.86	56.15	11.31	66.89	93.50
2034	30.63	0.07	0.86	60.50	11.96	69.07	92.86
2035	32.39	0.06	0.87	67.04	13.02	63.21	91.68

Appendix Table A.4 Model Results: Yearly EEG surcharge (Cents/kWh) for privileged and unprivileged consumer categories

Year	EEG Surcharge (15% Category)	EEG Surcharge (20% Category)	EEG Surcharge (Railways)	EEG Surcharge (Unprivilaged)
2015	0.68	0.90	0.90	6.37
2016	0.70	0.93	0.93	6.60
2017	0.73	0.97	0.97	6.84
2018	0.75	1.00	1.00	7.09
2019	0.78	1.04	1.04	7.34
2020	0.79	1.05	1.05	7.44
2021	0.81	1.07	1.07	7.59
2022	0.82	1.09	1.09	7.72
2023	0.83	1.11	1.11	7.84
2024	0.83	1.11	1.11	7.82
2025	0.82	1.10	1.10	7.75
2026	0.81	1.08	1.08	7.62
2027	0.79	1.06	1.06	7.47
2028	0.78	1.04	1.04	7.32
2029	0.75	1.00	1.00	7.06
2030	0.69	0.92	0.92	6.48
2031	0.63	0.84	0.84	5.97
2032	0.56	0.74	0.74	5.25
2033	0.52	0.70	0.70	4.92
2034	0.54	0.71	0.71	5.05
2035	0.56	0.75	0.75	5.27

Appendix B. Data relating to Network Charges Model

Appendix Table B.1 Model Results: Yearly transmission, distribution, services costs and aggregated network costs

Year	Transmission Costs (Mio. Euros)	Distribution Costs (Mio. Euros)	Services Costs (Mio. Euros)	Total Network Costs (Bio. Euros)
2015	2895.98	15595.17	1399.51	19.89
2016	3227.93	15865.71	772.70	19.87
2017	3554.94	16130.87	737.44	20.42
2018	3876.99	16390.63	697.72	20.97
2019	4194.10	16645.00	649.70	21.49
2020	4506.26	16893.98	583.61	21.98
2021	4813.48	17137.56	524.99	22.48
2022	5115.74	17375.76	461.90	22.95
2023	5413.07	17608.56	394.92	23.42
2024	5705.44	17835.97	398.88	23.94
2025	5992.87	18057.99	403.18	24.45
2026	6275.35	18274.62	406.80	24.96
2027	6552.88	18485.86	410.69	25.45
2028	6825.47	18691.71	414.90	25.93
2029	7093.11	18892.16	419.12	26.40
2030	7355.80	19087.22	421.66	26.86
2031	7613.55	19276.90	424.98	27.32
2032	7866.35	19461.18	427.64	27.76
2033	8114.20	19640.07	432.17	28.19
2034	8357.10	19813.56	436.71	28.61
2035	8595.06	19981.67	439.95	29.02

Appendix Table B.2 Model Results: Yearly average network charges for household/SME, unprivileged industry and StromNEV-19 surcharge for categories A, B, C in Cents/kWh

Year	Network Charge Household/SME	Network Charge Unprevilaged Industry	StromNEV-19 Surcharge Category- A	StromNEV-19 Surcharge Category-B	StromNEV-19 Surcharge Category-C
2015	6.882	2.059	0.388	0.050	0.025
2016	6.873	2.057	0.387	0.050	0.025
2017	7.063	2.114	0.399	0.050	0.025
2018	7.248	2.169	0.411	0.050	0.025
2019	7.427	2.222	0.422	0.050	0.025
2020	7.596	2.273	0.432	0.050	0.025
2021	7.764	2.323	0.442	0.050	0.025
2022	7.927	2.372	0.452	0.050	0.025
2023	8.085	2.419	0.462	0.050	0.025
2024	8.263	2.473	0.473	0.050	0.025
2025	8.439	2.525	0.484	0.050	0.025
2026	8.610	2.576	0.495	0.050	0.025
2027	8.778	2.627	0.505	0.050	0.025
2028	8.943	2.676	0.515	0.050	0.025
2029	9.104	2.724	0.525	0.050	0.025
2030	9.261	2.771	0.535	0.050	0.025
2031	9.415	2.817	0.544	0.050	0.025
2032	9.565	2.862	0.554	0.050	0.025
2033	9.712	2.906	0.563	0.050	0.025
2034	9.856	2.949	0.572	0.050	0.025
2035	9.996	2.991	0.580	0.050	0.025

Appendix C. Data relating to KWKG model

Appendix Table C.1 Dataset from (Öko-Institut, 2015) featuring yearly additional capacities in MWs coming under KWKG support mechanism categorized as per category M, C1, C2, C3

Year	Cat-M	Cat-C1	Cat-C2	Cat-C3
2009	94	260	115	55
2010	166	427	134	40
2011	23	335	173	52
2012	211	266	195	53
2013	796	295	242	62
2014	836	400	324	81

Appendix Table C.2 Model Results: Aggregated yearly installed capacities, generation, costs and KWKG surcharge values as resulted from model calculations

Year	Installed Capacity (GW)	KWK Generation (TWh)	Support Cost (Mio. Euros)	Base KWKG-Surcharge (Cents/kWh)
2017	10307	33	1047	0.3885
2018	12260	39	1239	0.4597
2019	13296	43	1313	0.4872
2020	13507	43	1329	0.4929
2021	13507	43	1329	0.4932
2022	13507	43	1330	0.4934
2023	13507	43	1330	0.4934
2024	13507	43	1330	0.4934
2025	13507	43	1330	0.4934
2026	13507	43	1330	0.4934
2027	13507	43	1330	0.4934
2028	13507	43	1330	0.4934
2029	13507	43	1330	0.4934
2030	13507	43	1330	0.4934
2031	13507	43	1330	0.4934
2032	13507	43	1330	0.4934
2033	13507	43	1330	0.4934
2034	13507	43	1330	0.4934
2035	13507	43	1330	0.4934

Declaration in lieu of oath

By

"Bilal Hussain"

This is to confirm my Master's Thesis was independently composed/authored by myself, using solely the referred sources and support.

I additionally assert that this Thesis has not been part of another examination process.

Place and Date *Signature*