Implementation of small grid connected decentralized power generators using renewable energies

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To:
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1 Renewable Electricity Policy and its Legislation

At least 83 countries worldwide have some type of policy to promote renewable power generation. The 10 most common policy types are feed-in tariffs, renewable portfolio standards, capital subsidies or grants, investment tax credits, sales tax or value added taxes exemptions, green certificate trading, direct energy production payments or tax credits, net metering, direct public investment or financing, and public competitive bidding [REN 21 2010].

The most common policy of all is the feed-in tariff, which has been enacted in many new countries and regions in recent years. By early 2010, at least 50 countries had adopted feed-in tariffs over the years, more than half of which have been enacted since 2005. The policies have spurred innovation and increased interest and investment in many countries. They have had the largest effect on wind power but have also influenced phovoltaics (PV), biomass, and small hydro development. Strong momentum for feed-in tariffs continues around the world as countries enact new policies or revise existing ones.

Table 1.a: Countries (states/provinces) enabling feed-in policies [REN 21 2010]

Year	Cumulative Number	Countries/States/Provinces Added That Year
1978	1	United States
1990	2	Germany
1991	3	Switzerland
1992	4	Italy
1993	6	Denmark, India
1994	8	Spain, Greece
1997	9	Sri Lanka
1998	10	Sweden
1999	13	Portugal, Norway, Slovenia
2000	13	–
2001	15	France, Latvia
2002	21	Algeria, Austria, Brazil, Czech Republic, Indonesia, Lithuania
2003	27	Cyprus, Estonia, Hungary, South Korea, Slovak Republic, Maharashtra (India)
2004	33	Israel, Nicaragua, Prince Edward Island (Canada), Andhra Pradesh and Madhya Pradesh (India)
2005	40	Karnataka, Uttarakhand, and Uttar Pradesh (India); China, Turkey, Ecuador, Ireland
2006	45	Ontario (Canada), Kerala (India), Argentina, Pakistan, Thailand
2007	54	South Australia (Australia), Albania, Bulgaria, Croatia, Dominican Rep., Finland, Macedonia, Mongolia, Uganda
2008	67	Queensland (Australia); California (USA); Chattisgarh, Gujarat, Haryana, Punjab, Rajasthan, Tamil Nadu, and West Bengal (India); Kenya, the Philippines, Tanzania, Ukraine
2009	77	Australian Capital Territory, New South Wales, Victoria (Australia); Japan; Serbia; South Africa; Taiwan; Hawaii; Oregon and Vermont (USA)
2010 (early)	78	United Kingdom

Note: Cumulative number refers to number of jurisdictions that had enacted a feed-in policy by the given year; however, polices in some countries were subsequently discontinued so the number of existing policies cited in this report is 75. See Endnote 236 for details. Many policies have been revised or reformulated in years subsequent to the initial year shown for a given country. India's national feed-in tariff from 1993 was substantially discontinued but new national feed-in tariffs were enacted in 2008. *Sources*: All available policy references, including the IEA online Global Renewable Energy Policies and Measures database and submissions from report contributors.

Net metering is an important policy for rooftop PV systems (as well as other renewables) that allows self generated power to offset electricity purchases. Net metering laws now exist in at least 10 countries and in 43 US states. Most net metering is only for small installations, but a growing number of regulations allow larger sized installations to qualify. At least 20 US states now allow net metering up to 1 MW for at least one customer type. Some net metering provisions cap total installations allowed to qualify for net metering, although caps may change over time. For example, California in 2010 increased the total capacity eligible for net metering to 5 % of peak system power demand, after the previous cap of 2.5 % was about to be reached. Net metering exists in a growing number of developing countries, for example Tanzania and Thailand. Net metering laws continue to evolve and become more sophisticated as new provisions address issues such as net excess generation, renewable energy credit ownership, and community owned systems.

In addition to subsidies and net metering, a few jurisdictions are beginning to mandate solar PV in selected types of new construction through building codes. Notable is Spain's 2006 building code, which mandates solar PV for certain types of new construction and renovations (also solar hot water).

Table 1.b: Countries and their renewable energy promotion policies [REN 21, 2010]

Country	Feed-in tariff	Renewable Portfolio Standard/quota	Capital subsidies, grants, rebates	Investment or other tax credits	Sales tax, energy tax, excise tax, or VAT reduction	Tradable RE certificates	Energy production payments or tax credits	Net metering	Public investment, loans, or financing	Public competitive bidding
EU-27										
Austria	X		X	X		X			X	
Belgium		(*)	X	X	X	X		X		
Bulgaria	X		X						X	
Cyprus	X		X							
Czech Republic	X		X	X	X	X		X		
Denmark	X		X	X	X	X		X	X	X
Estonia	X		X		X		X			
Finland	X		X		X	X	X			
France	X		X	X	X	X			X	X
Germany	X		X	X	X			X	X	
Greece	X		X	X				X	X	
Hungary	X		X	X	X				X	X
Ireland	X		X	X		X				X
Italy	X	X	X	X	X	X		X	X	
Latvia	X				X				X	X
Lithuania	X		X	X	X				X	
Luxembourg	X		X	X	X					
Malta			X		X			X		
Netherlands			X	X	X	X	X			
Poland		X	X		X	X			X	X
Portugal	X		X	X	X				X	X
Romania		X			X	X			X	
Slovakia	X			X	X				X	
Slovenia	X		X	X	X	X			X	X
Spain	X		X	X	X	X			X	
Sweden		X	X	X	X	X	X		X	
United Kingdom	X	X	X		X	X			X	

Table 1.b continued

Country	Feed-in tariff	Renewable Portfolio Standard/quota	Capital subsidies, grants, rebates	Investment or other tax credits	Sales tax, energy tax, excise tax, or VAT reduction	Tradable RE certificates	Energy production payments or tax credits	Net metering	Public investment, loans, or financing	Public competitive bidding
Australia	(*)	X	X			X			X	
Belarus									X	
Canada	(*)	(*)	X	X	X			X	X	X
Israel	X				X					X
Japan	X	X	X	X		X		X	X	
Macedonia	X									
New Zealand			X						X	
Norway			X		X	X			X	
Russia			X			X				
Serbia	X									
South Korea	X		X	X	X				X	
Switzerland	X		X		X					
Ukraine	X									
United States	(*)	(*)	X	X	(*)	(*)	X	(*)	(*)	(*)
Algeria	X			X	X					
Argentina	X		X	(*)	X		X		X	X
Bolivia					X					
Brazil				X					X	X
Chile		X	X	X	X				X	X
China	X	X	X	X	X		X		X	X
Costa Rica							X			
Dominican Republic	X		X	X	X					
Ecuador	X			X						
Egypt					X					X
El Salvador				X	X				X	
Ethiopia					X					
Ghana			X		X				X	
Guatemala				X	X					
India	(*)	(*)	X	X	X	X	X		X	
Indonesia	X			X	X					
Iran				X			X			
Jordan					X			X	X	
Kenya	X			X						
Malaysia									X	
Mauritius			X							
Mexico				X				X	X	X
Mongolia	X									X
Morocco				X	X				X	
Nicaragua	X			X	X					
Pakistan	X							X		
Palestinian Territories					X					
Panama							X			
Peru				X	X		X			X
Philippines	X	X	X	X	X		X	X	X	X
Rwanda									X	
South Africa	X		X		X				X	X
Sri Lanka	X									
Tanzania	X		X		X					
Thailand	X				X				X	
Tunisia			X		X				X	
Turkey	X		X							
Uganda	X		X		X				X	
Uruguay		X								X
Zambia					X					

2 Legal Framework of a feed-in-law – the case of Germany

Generally speaking, the purpose of renewable energy legislation is to facilitate a sustainable development of energy supply, particularly for the sake of protecting the climate and the environment, to reduce the costs of energy supply to the national economy, also by incorporating external long-term effects, to conserve fossil fuels and to promote the further development of technologies for the generation of electricity from renewable energy sources [EEG, 2009a].

In order to achieve the aforementioned goal of the legislation, the German Renewable Energy Source Act (EEG) aims to increase the share of renewable energy sources in electricity supply to at least 30 % (about 5 % before the establishment of the EEG) by the year 2020 and to continuously increase that share thereafter. The Act regulates:

- the priority connection to the grid systems for general electricity supply of installations generating electricity from renewable energy sources and from mine gas within the territory of Germany, including its exclusive economic zone (territorial application of this Act),
- the priority purchase, transmission, distribution of and payment for such electricity by the grid system operators, and
- the nationwide equalization scheme for the quantity of electricity purchased and paid for.

2.1 Grid Connection

Grid system operators shall immediately and as a priority connect installations generating electricity from renewable energy sources and from mine gas to that point in their grid system (grid connection point) which is suitable in terms of the voltage and which is at the shortest linear distance from the location of the installation if no other grid system has a technically and economically more favourable grid connection point. In the case of one or several installations with a total maximum capacity of 30 kW located on a plot of land which already has a connection to the grid system, the grid connection point of this plot shall be deemed to be its most suitable connection point.

Installation operators shall be entitled to choose another grid connection point in this grid system or in another grid system which is suitable with regard to the voltage. The grid system operator shall be entitled to assign for the installation a different grid connection point.

The obligation to connect the installation to the grid system shall also apply where the purchase of the electricity is only made possible by optimizing, boosting or expanding the grid system in accordance with the clause of grid expansion.

Insofar as it is necessary for the determination of the grid connection point and for the planning of the grid system operator, those interested in feeding in electricity and grid system operators must submit to each other, upon request and within eight weeks, the necessary documentation, in particular the grid system data required to test and verify the grid compatibility.

2.2 Technical and Operational Requirements

Installation operators shall provide installations whose capacity exceeds 100 kW with a technical or operational facility

- to reduce output by remote means in the event of grid overload, and
- to call up the current electricity feed-in at any given point in time to which the grid system operator may have access, and
- they shall also ensure that a wind powered installation fulfils the requirements of the Ordinance at the grid connection point with the grid system either on its own or in combination with other installations.

2.3 Establishment and Use of Connection

Installation operators shall be entitled to commission the grid system operator or a qualified third party with connecting the installations as well as with establishing and operating the metering devices, including the taking of measurements.

Implementation of this connection and the other installations required for the safety of the grid system shall meet the technical requirements of the grid system operator in a given case.

Where electricity from renewable energy sources or from mine gas is fed into the grid system, Low-Voltage Connection Ordinance shall apply.

2.4 Purchase, Transmission and Distribution

Grid system operators shall immediately and as a priority purchase, transmit and distribute the entire available quantity of electricity from renewable energy sources and from mine gas.

These obligations shall also apply if the installation is connected to the grid system of the installation operator or of a third party who is not a grid system operator and the electricity is delivered via this grid system to a grid system for commercial and accounting purposes.

These obligations shall not apply where installation operators and grid system operators agree by contract to deviate from this priority purchase in order to better integrate the installation into the grid system.

In the relationship to the purchasing grid system operator who is not the transmission system operator, the obligations in respect of priority purchase, transmission and distribution refer to:

- the upstream transmission system operator,
- the nearest domestic transmission system operator if there is no domestic transmission grid system in the area serviced by the grid operator entitled to sell the electricity, or
- particularly in the case of delivery in accordance with the purchase, transmission and distribution, any other grid system operator.

2.5 Grid Capacity Expansion

Upon the request of those interested in feeding in electricity, grid system operators shall immediately optimize, boost and expand their grid systems in accordance with the best available technology in order to guarantee the purchase, transmission and distribution of the electricity generated from renewable energy sources or from mine gas. They shall inform the installation operator without delay as soon as the risk arises that technical control will be assumed over their installation; the expected time, extent and duration of the control shall be communicated. The grid system operator shall immediately publish the information required in accordance with the second sentence above on his website and shall thereby describe the affected regions of the grid system and the reasons for the risk.

This obligation shall apply to all technical facilities required for operating the grid system and to all connecting installations which are owned by or passing into the ownership of the grid system operator.

The grid system operator shall not be obliged to optimize, boost or expand his grid system if this is economically unreasonable.

2.6 Feed-in Management

Notwithstanding their obligation in accordance with grid capacity expansion, grid system operators shall be entitled, by way of exception, to take technical control over installations connected to their grid system with a capacity of over 100 kW for the generation of electricity from renewable energy sources, combined heat and power generation or mine gas, if

- the grid capacity in the respective grid system area would otherwise be overloaded on account of that electricity,
- they have ensured that the largest possible quantity of electricity from renewable energy sources and from combined heat and power generation is being purchased, and
- they have called up the data on the current feed-in situation in the relevant region of the grid system. Taking technical control over installations in accordance with the first sentence above shall only be permitted for a transitional period until measures referred to in grid capacity expansion are concluded.

Grid system operators shall, upon the request of those installation operators whose installations were affected by measures referred to under feed in management, provide verification, within four weeks, for the need for the measure.

2.7 Grid Connection Costs

The costs associated with connecting installations generating electricity from renewable energy sources or from mine gas to the grid connection point and with installing the necessary metering devices for recording the quantity of electricity transmitted and received shall be borne by the installation operator (as defined in grid connection under section 1.2.1 above).

2.8 Tariffs and Degression Rates

The tables in section 2.12 indicate minimum feed-in tariffs and degression rates for electricity produced from renewable energy sources and mine gas for the period 2009 to 2018 pursuant to the Renewable Energy Sources Act in its version of October 2008, different tariffs and rates applying depending on the year an installation is commissioned. In most cases, installations first commissioned prior to 2009 are subject to the older legislation so that different rules apply. Installations initially operating on conventional energies and switching to renewable energies after December 31, 2008 are also subject to the older legislation.

2.9 Calculating the Output of an Installation

Where tariffs vary depending on output levels, they are determined separately for each share of an installation's output which falls between the relevant threshold values. In this case the output of an installation will not be deemed to be its effective output, but rather the ratio of the total kWh fed into the grid in the calendar year in question to the total number of full hours for that calendar year. This provision does not apply to wind and solar energy.

2.10 Duration of Tariff Payment

The minimum tariffs are paid from the time of commissioning for a period of 20 years, as well as for the year in which the installation was commissioned; for hydroelectric power installations with a capacity of over 5 MW a 15 year period applies.

2.11 Degression Rate

The tariffs described later in the report refer to installations commissioned on or after January 01, 2009. As a rule, tariffs for installations commissioned after 2009 are lowered on January 1^{st} of each following year by a fixed percentage (degression rate). Numbers are to be rounded to the second digit after the decimal point. The degression rate is calculated on the basis of the previous year's unrounded value. Examples of degression rates applying to different renewable energy installation types are given below [EEG 2009b].

2.12 Tariffs and Costs for the different renewable electricity generation technologies

As an indicator for the costs of the different renewable electricity generation facilities in this report the tariffs paid as feed-in-tariffs are taken as an indicator. The intention of the legislative body has been to give to people and investors who invest in renewable energies the possibility to achieve a profit margin of somewhat between six and nine percent.

It has to be mentioned that the costs differ from installation site to installation site or also from one country to another country. Solar and wind energy depend strongly on solar and wind resources. Therefore, e.g. photovoltaics can be more or less twice as efficient in Brazil as it is in Germany.

2.12.1 Tariffs for Electricity from Hydropower

New Installations of up to 5 MW

No degression, duration of tariff payment: 20 years

Table 2.12.1.a: Tariffs for electricity from hydropower – new installations [EEG 2009b]

Year of commissioning	up to 500kW in ct/kWh	500kW - 2MW in ct/kWh	2MW - 5MW in ct/kWh
2009	**12.67**	**8.65**	**7.65**
2010	12.67	8.65	7.65
2011	12.67	8.65	7.65
2012	12.67	8.65	7.65
2013	12.67	8.65	7.65
2014	12.67	8.65	7.65
2015	12.67	8.65	7.65
2016	12.67	8.65	7.65
2017	12.67	8.65	7.65
2018	12.67	8.65	7.65

Modernized/revitalized Installations of up to 5 MW

No degression, duration of tariff payment: 20 years

Table 2.12.1.b: Tariffs for electricity from hydropower – modernized installations [EEG 2009b]

Year of modernisation/revitalisation	up to 500kW in ct/kWh	500kW – 5MW
2009	**11.67**	**8.65**
2010	11.67	8.65
2011	11.67	8.65
2012	11.67	8.65
2013	11.67	8.65
2014	11.67	8.65
2015	11.67	8.65
2016	11.67	8.65
2017	11.67	8.65
2018	11.67	8.65

New or modernized installations are only eligible if a good ecological status or a substantial improvement of the previous ecological status has demonstrably been brought about.

New and Modernized Installations above 5 MW

Degression rate: 1.0 %; duration of tariff payment: 15 years

Table 2.12.1.c: Tariffs for hydroelectricity – modernized installations (> 5 MW) [EEG 2009b]

Year of commissioning	up to 500kW in ct/kWh	up to 10MW in ct/kWh	up to 20MW in ct/kWh	up to 50MW in ct/kWh	above 50MW in ct/kWh
2009	**7.29**	**6.32**	**5.80**	**4.34**	**3.50**
2010	7.22	6.26	5.74	4.30	3.47
2011	7.14	6.19	5.68	4.25	3.43
2012	7.07	6.13	5.63	4.21	3.40
2013	7.00	6.07	5.57	4.17	3.36
2014	6.93	6.01	5.52	4.13	3.33
2015	6.86	5.95	5.46	4.09	3.30
2016	6.79	5.89	5.41	4.05	3.26
2017	6.73	5.83	5.35	4.00	3.23
2018	6.66	5.77	5.30	3.96	3.20

Tariffs in the case of modernized installations are paid only for the additional electricity imputable to the modernization.

2.12.2 Tariffs for Electricity from Landfill, Sewage and Mine Gas

Landfill Gas

Degression rate: 1.5 %, duration of tariff payment: 20 years

Table 2.12.2.a: Tariffs for electricity from landfill gas [EEG 2009b]

Year of commissioning	up to 500kW$_{el}$ in ct/kWh	500kW - 5MW$_{el}$ in ct/kWh
2009	**9.00**	**6.16**
2010	8.87	6.07
2011	8.73	5.98
2012	8.60	5.89
2013	8.47	5.80
2014	8.34	5.71
2015	8.22	5.63
2016	8.10	5.54
2017	7.98	5.46
2018	7.86	5.38

Sewage Gas

Degression rate: 1.5 %, duration of tariff payment: 20 years

Table2.12.2.b: Tariffs for electricity from sewage gas [EEG 2009b]

Year of commissioning	up to 500kW$_{el}$ in ct/kWh	500kW$_{el}$ - 5MW$_{el}$ in ct/kWh
2009	**7.11**	**6.16**
2010	7.00	6.07
2011	6.90	5.98
2012	6.79	5.89
2013	6.69	5.80
2014	6.59	5.71
2015	6.49	5.63
2016	6.40	5.54
2017	6.30	5.46
2018	6.21	5.38

The installation is eligible even if gas is withdrawn from the gas grid, if the thermal equivalent of the withdrawn quantity of gas equals that of the quantity of landfill or sewage gas injected into the gas grid elsewhere.

Mine Gas

Degression rate: 1.5 %, duration of tariff payment: 20 years

Table 2.12.2.c: Tariffs for electricity from mine gas [EEG 2009b]

Year of commissioning	up to 500kW$_{el}$ in ct/kWh	500kW$_{el}$ - 1MW$_{el}$ in ct/kWh	1MW$_{el}$ - 5MW$_{el}$ in ct/kWh	above 5MW$_{el}$ in ct/kWh
2009	**7.16**	**7.16**	**5.16**	**4.16**
2010	7.05	7.05	5.08	4.10
2011	6.95	6.95	5.01	4.04
2012	6.84	6.84	4.93	3.98
2013	6.74	6.74	4.86	3.92
2014	6.64	6.64	4.78	3.86
2015	6.54	6.54	4.71	3.80
2016	6.44	6.44	4.64	3.74
2017	6.34	6.34	4.57	3.69
2018	6.25	6.25	4.50	3.63

Technology Bonus Pursuant to the Act

Tariffs for landfill, sewage and mine gas may be increased by a technology bonus of 1.0 or 2.0 €ct/kWh if innovative procedures are applied that benefit the environment. The bonus is applicable to installations with a capacity of up to 5 MW$_{el}$ and is subject to a degression rate of 1.5 %.

Processing of Landfill and Sewage Gas

- up to a maximum of 350 Nm³/hour: 2.0 €ct/kWh
- up to a maximum of 700 Nm³/hour: 1.0 €ct/kWh
- Innovative installation technology: 2.0 €ct/kWh (This includes the use of fuel cells, gas turbines, steam engines, organic Rankine cycles, multi-fuel facilities, Stirling engines)

2.12.3. Tariffs for Electricity from Biomass

Payments for Installations Generating Electricity from Biomass

Degression rate: 1.0 %, duration of tariff payment: 20 years

Table 2.12.3.a: Tariffs for electricity from biomass [EEG 2009b]

Year of commissioning	up to 150kW$_{el}$ in ct/kWh	150 - 500kW$_{el}$ in ct/kWh	500kW$_{el}$ - 5MW$_{el}$ in ct/kWh	5MW$_{el}$ - 20MW$_{el}$ in ct/kWh
2009	**11.67**	**9.18**	**8.25**	**7.79**
2010	11.55	9.09	8.17	7.71
2011	11.44	9.00	8.09	7.63
2012	11.32	8.91	8.00	7.56
2013	11.21	8.82	7.92	7.48
2014	11.10	8.73	7.85	7.41
2015	10.99	8.64	7.77	7.33
2016	10.88	8.56	7.69	7.26
2017	10.77	8.47	7.61	7.19
2018	10.66	8.39	7.54	7.12

Installations with a capacity of more than 5 MW are only eligible when operating in CHP mode with reasonable utilization of heat and only with respect to the share of electricity generated by CHP.

Installations with an installed capacity of more than 20 MW are also eligible for pro rata payment of the above mentioned tariffs with respect to a share of output of 20 MW.

The tariff paid may be increased by 1.0 €ct/kWh with respect to a share of output of up to 500 kW$_{el}$ if installations subject to utilize gas produced by anaerobic digestion of the biomass and respect corresponding formaldehyde limits.

Possible increases in total payments through different bonuses (e.g. for the use of energy crops, innovative technologies) are also subject to the 1.0 % degression rate.

Table 2.12.3.b: Bonuses from biomass [EEG 2009b]

Bonus for electricity from energy crops			
	EEG tariff ct/kWh		**EEG** tariff ct/kWh
Share of output up to 150 kW_{el} *Biomass with the exception of biogas* *Biogas* *- using at least a 30% share of slurry* *- using mostly residues from landscape management activities*	 6.00 7.00 + 4.0 + 2.0	***Share of output up to 500 kW_{el}*** *Biomass with the exception of biogas* *- solid biomass* *- liquid biomass* *- gaseous biomass (with the exception of biogas)* *Biogas* *- using at least a 30% share of slurry* *- using mostly residues from landscape management activities*	 6.00 0.00 6.00 7.00 + 1.0 + 2.0
Share of output up to 5 MW_{el} *Biomass including biogas* *- solid biomass* *- liquid biomass* *- gaseous biomass* *- burning of wood* *- burning of wood from short-rotation plantations and landscape management activities*	 4.00 0.00 4.00 2.50 4.00		

Technology bonus (for installations of up to 5MW_{el}) pursuant to annex 1	**EEG** tariff ct/kWh
Innovative installation technology	2.00
For processing of gas: a) up to a maximum of 350Nm³/hour b) up to a maximum of 700Nm³/hour	 2.00 1.00

CHP bonus (for a share of output of up to 20MW_{el}, only for that share of electricity fed into the grid that is classified as CHP electricity)	**EEG** tariff ct/kWh
	3.00 [5)]

[5)] This also applies to existing installations if these are first used as CHP installations within the meaning of annex 3 after 31 December 2008 and, on a pro-rata basis, to other existing installations for a share of output of up to 500 kW if the conditions set out in annex 3 are complied with.

2.12.4 Tariffs for Electricity from Geothermal Energy

In the field of geothermal power, the higher tariffs of the new Act apply to new installations commissioned on or after January 01, 2009. The bonuses also apply with retroactive effect to existing installations.

Geothermal Energy

Degression rate: 1.0 %, duration of tariff payment: 20 years

Table 2.12.4.a: Tariffs for electricity from geothermal energy [EEG 2009b]

Year of commissioning	up to $10MW_{el}$ in ct/kWh	above 10MW in ct/kWh
2009	**16.00**	**10.50**
2010	15.84	10.40
2011	15.68	10.29
2012	15.52	10.19
2013	15.37	10.09
2014	15.22	9.99
2015	15.06	9.89
2016	14.91	9.79
2017	14.76	9.69
2018	14.62	9.59

Bonuses for Geothermal Energy

Degression rate: 1.0 %, duration of tariff payment: 20 years

Table 2.12.4.b: Bonuses for geothermal energy [EEG 2009b]

Heat use bonus	**EEG** tariff ct/kWh
for installations of up to $10MW_{el}$ *with heat use pursuant to annex 4*	3.00
Technology bonus	
for installations of up to $10MW_{el}$ using petrothermal technology	4.00
Early bird bonus	
bonus in accordance with section 28 subsection (1a) EEG for installations commissioned before 1 January 2016	4.00

2.12.5 Tariffs for Electricity from Wind Energy

<u>Onshore Wind Energy</u>

Degression rate: 1.0 %, duration of tariff payment: 20 years

Table 2.12.4.a: Tariffs for electricity from onshore wind energy [EEG 2009b]

Year of commissioning	Initial tariff[7)] in ct/kW	Basic tariff in ct/kWh	System services bonus [8)]	Repowering bonus [9]
2009	**9.20**	**5.02**	**0.50**	**0.50**
2010	9.11	4.97	0.50	0.50
2011	9.02	4.92	0.49	0.49
2012	8.93	4.87	0.49	0.49
2013	8.84	4.82	0.48	0.48
2014	8.75	4.77	0.0	0.48
2015	8.66	4.73	0.0	0.47
2016	8.58	4.68	0.0	0.47
2017	8.49	4.63	0.0	0.46
2018	8.40	4.59	0.0	0.46

[7)] The higher initial tariff is paid for five years. This period is extended pursuant to section 29 subsection (2) by two months for each 0.75 per cent of the reference yield by which the yield of the installation falls short of 150 per cent of the reference yield.
[8)] Pursuant to section 29 subsection (2), the system services bonus for new installations is paid for the same period as the higher initial tariff. Existing installations commissioned after 31 December 2001 and prior to 1 January 2009 are eligible for a system services bonus pursuant to section 66 subsection (6) of 0.7ct for a period of five years. This payment is contingent on the technical retrofitting of the existing installations by 1 January 2011.
[9)] The repowering bonus pursuant to section 30 for the replacement of existing wind energy installations on the same or on an adjacent site is paid for the same period as the higher initial tariff.

Extension of the Higher Initial Tariff

Table 2.12.4.b: Extension of the higher initial tariff [EEG 2009b]

Reference yield in (%)	Initial tariff pursuant to section 29 subsection (2), first sentence	Extension of the initial tariff pursuant to section 29 subsection (2), first sentence	Total duration of payment of the initial tariff
>= 150	5 years	-	5 years
142,5	5 years	20 months	6 years, 8 months
135	5 years	40 months	8 years, 4 months
127,5	5 years	60 months	10 years
120	5 years	80 months	11 years, 8 months

Offshore Wind Energy

Degression rate until 2014: 0.0 %; from 2015: 5 %; duration of tariff payment: 20 years

Table 2.12.4.c: Tariffs for electricity from offshore wind energy [EEG 2009b]

	Initial tariff in ct/kWh [10)]	Early bird bonus[11)]	Basic tariff in ct/kWh
2009	**13**	**2**	**3.5**
2010	13	2	3.5
2011	13	2	3.5
2012	13	2	3.5
2013	13	2	3.5
2014	13	2	3.5
2015	12.35	1.90	3.33
2016	11.73	0.0	3.16
2017	11.15	0.0	3.00
2018	10.59	0.0	2.85

[10)] The higher initial tariff for offshore wind energy is paid in the first 12 years after the installation is commissioned. The period is extended in accordance with section 31 subsection (2), third sentence, for electricity from installations located at least twelve nautical miles seawards and in a water depth of at least 20 metres: by 0.5 months for each full nautical mile beyond 12 nautical miles and by 1.7 months for each additional full metre of water depth.
[11)] Pursuant to section 31 subsection (2), second sentence, the early bird bonus is paid for the same period as the higher initial tariff.

2.12.5 Tariffs for Electricity from Solar Radiation Energy

The degression rate for PV installations is adjusted on the basis of the annual capacity increase in Germany. The degression rates given below may change as early as 2010 and in the following years[1]. By October 31st of each year, the Federal Network Agency, in agreement with the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety and the Federal Ministry of Economics and Technology, publishes in the Federal Gazette the notified increase in installed capacity and the resulting degression rate applicable in the following year as well as the applicable tariff levels.

Free-standing Installations[2]

Degression rate[3]: from 2010: 10 %; from 2011: 9 %

Eligibility criteria for free-standing installations are compliance with the site categories, as a rule, the existence of a binding land-use plan (Bebauungsplan).

[1] On 06.05.2010 the German Bundestag adopted the amendment of the Renewable Energy Sources Act. It reduces the feed-in tariffs for solar power generated by installations on buildings and in open spaces as per July 01, 2010. The tarrifs and examples are valid until this time.

[2] These tariffs not only apply to free-standing installations, but also to installations mounted on top of physical structures that cannot be classified as buildings. Free-standing installations commissioned after December 31, 2014 are no longer eligible for payments.

[3] The degression rate is adjusted on the basis of the annual capacity increase. From 2009, PV installation operators are required to notify the Federal Network Agency of the capacity of their new build. The degression rate does not change if the notified increase in installed capacity comprises between 1.0 and 1.5 MW in the year 2009 (between 1.1 and 1.7 MW in 2010, between 1.2 and 1.9 MW in 2011). If the annual increase in installed capacity exceeds this corridor, the degression rate increases by one percentage point, if it is lower, the degression rate is reduced by one percentage point. The Federal Network Agency, in agreement with the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety and the Federal Ministry of Economics and Technology, publishes the new build data in the Federal Gazette.

Table 2.12.5.a: Tariffs for electricity from free standing PV systems [EEG 2009b]

Year of commissioning	Irrespective of share of capacity in ct/kWh
2009	**31.94**
2010	*28.75 (+/-1%)*
2011	*26.16*
2012	*23.80*
2013	*21.66*
2014	*19.71*
2015	*17.94*
2016	*16.32*
2017	*14.85*
2018	*13.52*

Installations Attached to or on Top of Buildings

Degression rate: Installations of up to 100 kW: in 2010: 8.0 %; from 2011: 9.0 %

Installations above 100 kW: in 2010: 10.0 %; from 2011: 9.0 %

On-site consumption: from 2010: 10.0 %, from 2011: 9.0 %

Take note of the effective degression rates published in the Federal Gazette!

Table 2.12.5.b: Tariffs for electricity from PV systems on top of buildings [EEG 2009b]

Year of commissioning	up to 30kW in ct/kWh	30kW – 100kW in ct /kWh	100 – 1,000kW in ct /kWh	above 1,000kW in ct /kWh	On-site consumption pur-suant to section 33 subsection (2) EEG
2009	**43.01**	**40.91**	**39.58**	**33.00**	**25.01**
2010	39.57 (+/-1%)	37.64 (+/-1%)	35.62 (+/-1%)	29.70 (+/-1%)	23.01 (+/-1%)
2011	*36.01*	*34.25*	*32.42*	*27.03*	*20.94*
2012	*32.77*	*31.17*	*29.50*	*24.59*	*19.05*
2013	*29.82*	*28.36*	*26.84*	*22.38*	*17.34*
2014	*27.13*	*25.81*	*24.43*	*20.37*	*15.78*
2015	*24.69*	*23.49*	*22.23*	*18.53*	*14.36*
2016	*22.47*	*21.37*	*20.23*	*16.87*	*13.07*
2017	*20.45*	*19.45*	*18.41*	*15.35*	*11.89*
2018	*18.61*	*17.70*	*16.75*	*13.97*	*10.82*

Self Consumption Tariff

The most recent amendment of the German Renewable Energy Sources Act that came into force on 1st January 2009 contains a first step towards domestic energy management. This amendment contains the first legal incentive to use PV energy for energy management. It guarantees a special tariff for PV plant operators when the system operator or a third party uses the electricity in the immediate proximity of the installation. As of 2009, the reimbursement for locally consumed electricity generated by PV is 25.01€ct/kWh, as compared to 43.01 c€/kWh if fed directly into the grid (table 2.12.5.c).

The costs of locally consumed electricity are specified by the difference between the reimbursement tariffs. For PV systems installed in 2009 the costs of locally consumed electricity generated by PV amount to 18 €ct/kWh. Due to an annual reduction of feed-in tariffs between 7-10%, the costs of locally consumed electricity will decrease for PV system installations concluded beyond 2009 (e.g. 13.56 €ct/kWh in 2012 assuming a degression of 9 %/a). The new tariff option becomes interesting if the electricity price (without value added tax) from the energy supplier exceeds the costs of locally consumed electricity generated by PV. According to the electricity price index of the German Federal Statistical Office the average electricity price (without VAT) is approximately 18 €ct/kWh in 2009. The extrapolation from the price increases of approximately 5%/a over the last 8 years leads to a projected price of 20.84 €ct/kWh in 2012 (table 2.12.5.c).

Table 2.12.5.c: Estimated benefit of self-consuming PV energy in €ct/kWh [Braun 2009b]

Year	**2009**	**2010**	**2011**	**2012**
PV direct feed-in tariff	43.01	39.14	35.62	32.41
PV local consumption tariff	25.01	22.76	20.71	18.85
Local consumption electricity costs	18.00	16.38	14.91	13.56
Electricity price (without VAT)	18	18.9	19.85	20.84
Estimated benefit = electricity price – local consumption costs	**0.00**	**2.52**	**4.94**	**7.27**

The benefits of locally consumed energy generated from PV are expected to rise due to the expected increase of electricity prices and the cost reduction of locally consumed electricity (e.g. for the year 2012: 20.84 €ct/kWh - 13.56 €ct/kWh = 7.27 €ct/kWh). The additional income will allow the implementation of energy management systems for improving the correlation between PV energy generation and local consumption.

2.13 Participation roles of the different actors

Delivery to Transmission System Operator

Grid system operators shall immediately deliver to the upstream transmission system operator the electricity for which tariffs are paid [EEG 2009a].

Tariffs Paid by Transmission System Operator

The upstream transmission system operator shall pay tariffs in accordance with the aforementioned criteria for the quantity of electricity for which the distribution grid system operator has paid tariffs.

Equalization amongst Transmission System Operators

The transmission system operators shall record the different quantities and temporal sequence of the quantities of electricity for which tariffs were paid, provisionally equalize the quantities of electricity amongst themselves without delay and settle the accounts with regard to the quantity of electricity and tariffs paid pursuant to next paragraph below.

By July 31st of each year the transmission system operators shall determine the quantity of electricity which they purchased and paid for in the previous calendar year and which they have provisionally equalized in accordance with the paragraph before, and shall determine the percentage share of this quantity in relation to the total quantity of electricity which the utility companies delivered to the final consumers in each area served by the individual transmission system operator in the previous calendar year.

Transmission system operators who had to purchase quantities greater than this average share shall be entitled to sell electricity to and receive tariffs from the other transmission system operators until these system operators have also purchased a quantity of electricity equal to the average share.

The transmission system operators shall transmit the electricity to downstream utility companies.

Delivery to Suppliers

Utility companies which deliver electricity to final consumers shall purchase and pay for that share of the electricity which their regular transmission system operator purchased and paid for in accordance with a profile made available in due time and approximated to the actually purchased quantity of electricity. This shall not apply to utility companies which, of the total quantity of electricity supplied by them, supply at least 50 % in accordance.

The share of the electricity to be purchased by a utility company shall be placed in relation to the quantity of electricity delivered by the utility company concerned and shall be determined in such a way that each utility company receives a relatively equal share. The share shall be calculated as the ratio of the total quantity of electricity paid for to the total quantity of electricity delivered to final consumers.

The tariffs as specified before shall be calculated as the expected average tariffs per kWh paid two quarters earlier by all grid system operators combined, less the charges for use of the grid avoided pursuant.

The transmission system operators shall assert claims held against the utility companies in accordance with first paragraph of this section arising from equalization by August 31st of the year following the feeding-in of electricity. Equalization for the actual quantities of electricity purchased and the tariffs paid shall take place in monthly installments before September 30th of the following year.

Electricity purchased in accordance with first paragraph may not be sold below the tariffs paid in accordance with third paragraph if it is marketed as electricity produced from renewable energy sources or as comparable electricity.

Final consumers who purchase electricity from a third party and not from a utility company shall be placed on an equal footing with utility companies.

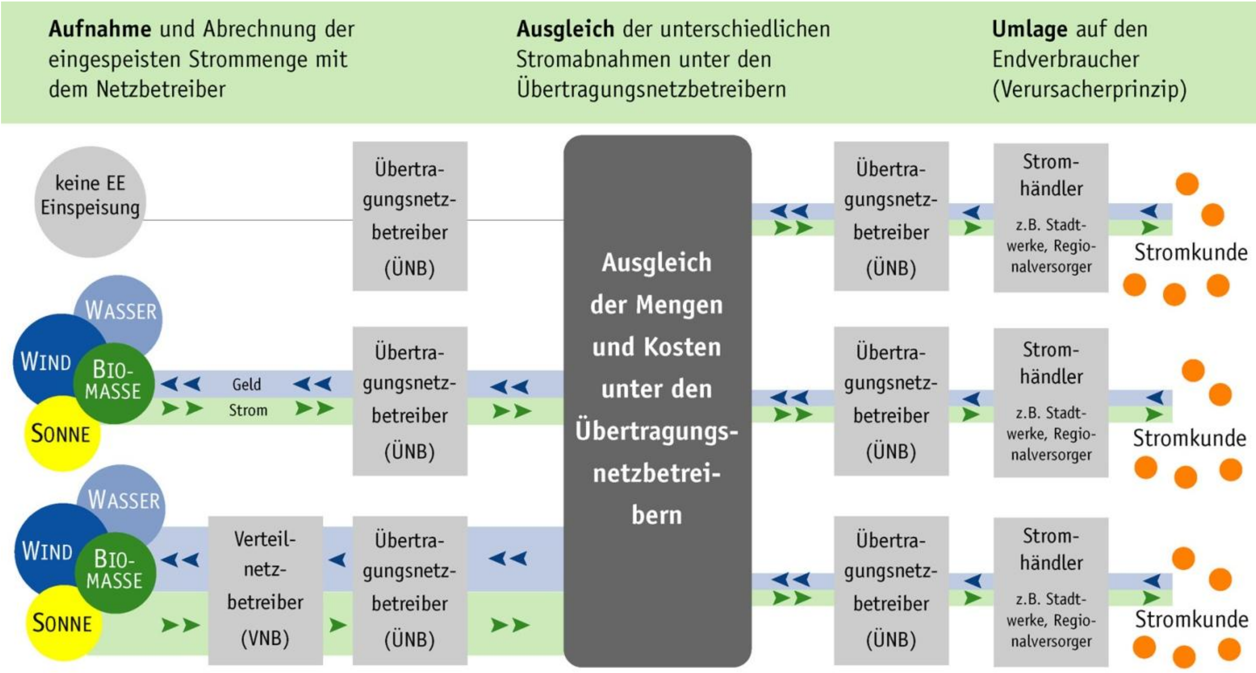

Illustration 2.13.1.a: Participation of the different actors in the equalization process [Source: unknown]

2.14 Impact on Consumer Tariffs

Needless to say, the electricity prices are increasing annually in most of the countries over past years. However, a variety of components go to make up the price of electricity and not only the renewable energy policy (such as subsidies and so on). Table 2.14.a below gives an overview of individual price components in Germany.

Among other things, the table shows that the costs of promoting renewable energies under the Renewable Energy Sources Act (EEG) are not public taxes or charges. The EEG surcharge does not go to the state, but to the operators of EEG plants. The EEG merely establishes a framework for the private sector relations between EEG plant operators and the grid operators and/or electricity suppliers.

Table 2.14.a: End user electricity price composition in Germany [BDEW]

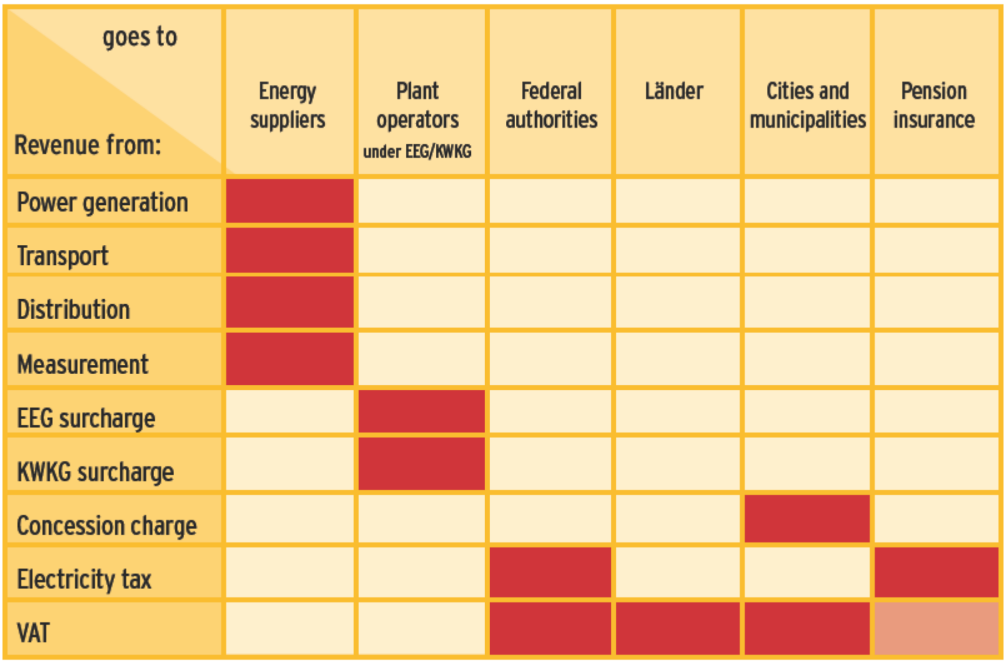

Illustration 2.14.a (data taken from BDEW) shows the EEG caused tariff increase for a kWh electricity price at household customers in Germany. The EEG is only one of eight price components that go to make up the price of household electricity.

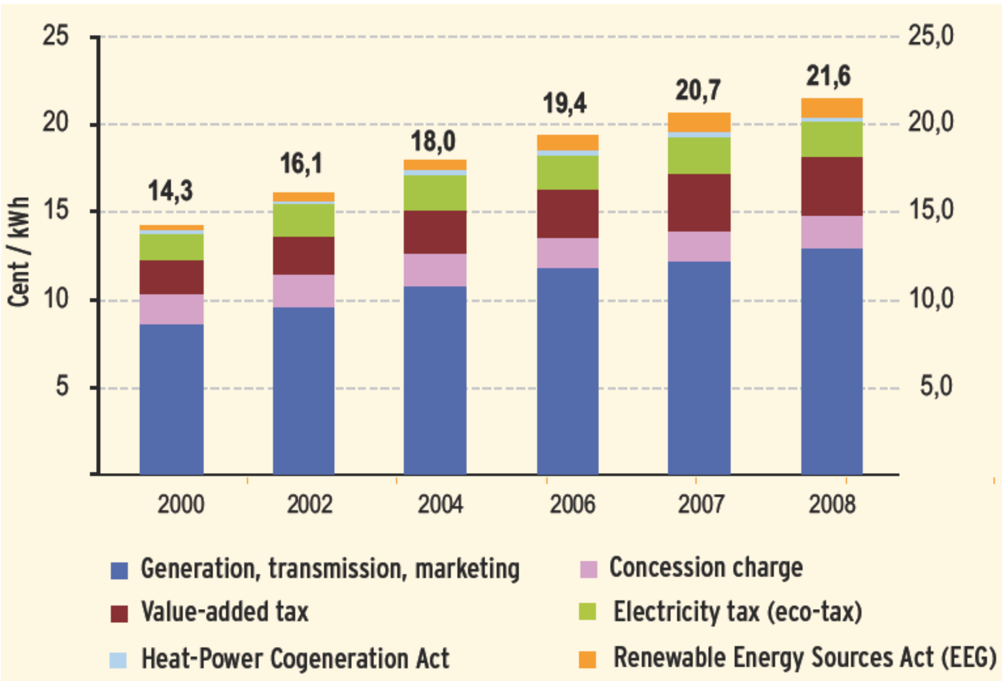

Illustration 2.14.a: End user electricity price development in Germany [BDEW]

According to BMU data (AGEE Stat), a total of around 91 TWh of electricity from renewable sources was generated in 2008 and fed into the grid. This was about 15 % of gross power consumption. Of this figure, about 71 TWh was subject to remuneration in accordance with the EEG. The average remuneration for the entire EEG electricity mix in this period was probably around 12 €ct/kWh. The total sum of EEG remuneration to plant operators was around € 8.8 billion.

Table 2.14.b shows how average monthly electricity costs for the reference household mentioned above have developed over the last seven years. The figures are based on data from the Federal Association of the Energy and Water Industries (BDEW). In 2008 the EEG surcharge, at about 1.1 €ct/kWh, only accounted for a bare 5 % of the total household electricity price.

Table 2.14.b1: End user electricity price composition in Germany [BDEW]

	2000	2002	2004	2006	2007	2008	2009
Electricity bill €/month (3,500 kWh/a)	**40,67**	**46,99**	**52,48**	**56,63**	**60,26**	**62,93**	**65,97**
Generation, transmission, marketing	25,15	28,32	31,56	34,53	35,70	38,01	40,48
Renewable Energy Sources Act (EEG)*	0,58	1,02	1,58	2,20	2,90	3,10	3,10
Heat-Power Cogeneation Act (KWKG)**	0,38	0,73	0,91	0,90	0,85	0,58	0,67
Concession charge***	5,22	5,22	5,22	5,22	5,22	5,22	5,22
Electricity tax (eco-tax)	3,73	5,22	5,97	5,97	5,97	5,97	5,97
Value-added tax	5,61	6,48	7,24	7,81	9,62	10,05	10,53
Electricity bill at 2005 prices	43,87	49,00	53,28	55,74	58,00	59,03	61,31

* Figures from 2005 onward: BMU calculations on the basis of applicable wholesale prices.

** From 2002 on the basis of the new Heat-and-power Cogeneration Act, which has been in force since 1 April 2002. Increase due to reduction in burden on manufacturing industry.

*** Great regional differences: 1.32 to 2.39 cent per kilowatt-hour from 2002 onward, depending on community size; some municipalities dispense with this income.

In individual cases there are naturally considerable variations in the size of the EEG surcharge, depending on electricity consumption. On the basis of the above mentioned spectrum for individual household or user types, the average EEG levy for 2008 mostly gives rise to household costs of between about 2 and 6 €/month.

Development of feed in electricity amount and monetary payment under the Electricity Feed Act (StrEG) and the EEG in Germany over the past years is given in illustration 2.14.b.

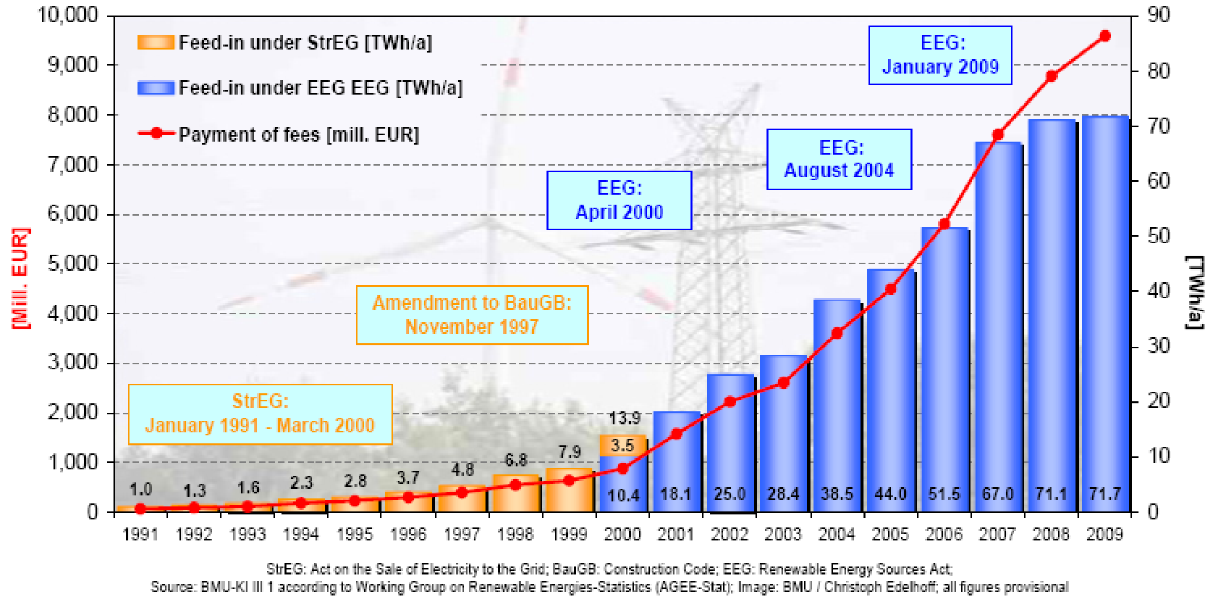

Illustration 2.14.b: Development of feed in electricity amount [BMU]

2.15 Financing Options for Decentralized Power Systems

The main barriers to the widespread use of renewable energy are the high up-front costs, particularly for installing equipment. To some degree, strengthening capacity building, promoting enabling environments, developing policy frameworks, and improving demands for renewable energy technologies can help mitigate steep transaction costs and underdeveloped markets. But even if those barriers are removed, the up-front investment costs of renewable energy projects will still be higher than those of conventional technologies.

Fortunately, many financial institutions (eco/green banks) already offer low interest loans for renewable energy, especially because of low risk on such investments, particularly in the countries where policy guarantees the long term revenue from the electricity. Other banks, working on climate change and environment protection issues, also provide such loans to those technologies such as PV, which can positively contribute to the global environment.

For the case of Brazil too, such institutions might already exist or they might emerge in the future, as long as the investment in RE sector is guaranteed by policy measures.

In order to realize the impact of bank interest rates on a kWh electricity generation price and thereby occurring grid parity, a grid parity curve has been plotted in the grid parity sub-chapter (section 4.4 - case 11) for the bank interest rate ranging from 0 to 15 %.

Current interest rates for photovoltaic systems in Germany vary something between 2.01 % and 8.06 % depending on among other criteria on the credit period [Photon 2010]. The majority of loans are around 4 %.

3 Legal Framework of net metering

Net metering is a special metering and billing arrangement between a utility and customers who choose to install renewable generation systems like wind turbines and PV panels and interconnect them to the utility. Net metering encourages the development of small scale renewable energy systems by providing increased savings to customers. It also ensures that customers have a reliable source of energy from their utility during times when their renewable generators are not producing energy [AmerenUE 2010].

Net metering is a program offered by a utility company for customers who install renewable or advanced energy systems to generate their own electricity. These systems can be used to offset a portion of the electric energy provided by the utility. Any excess energy generated by the customer during the monthly billing cycle would be sold to the utility company and credited to the customer.

In order to utilize net metering, the customer's generation must be interconnected to the utility grid with a meter that can register the amount of electric energy that is used and produced during the billing cycle.

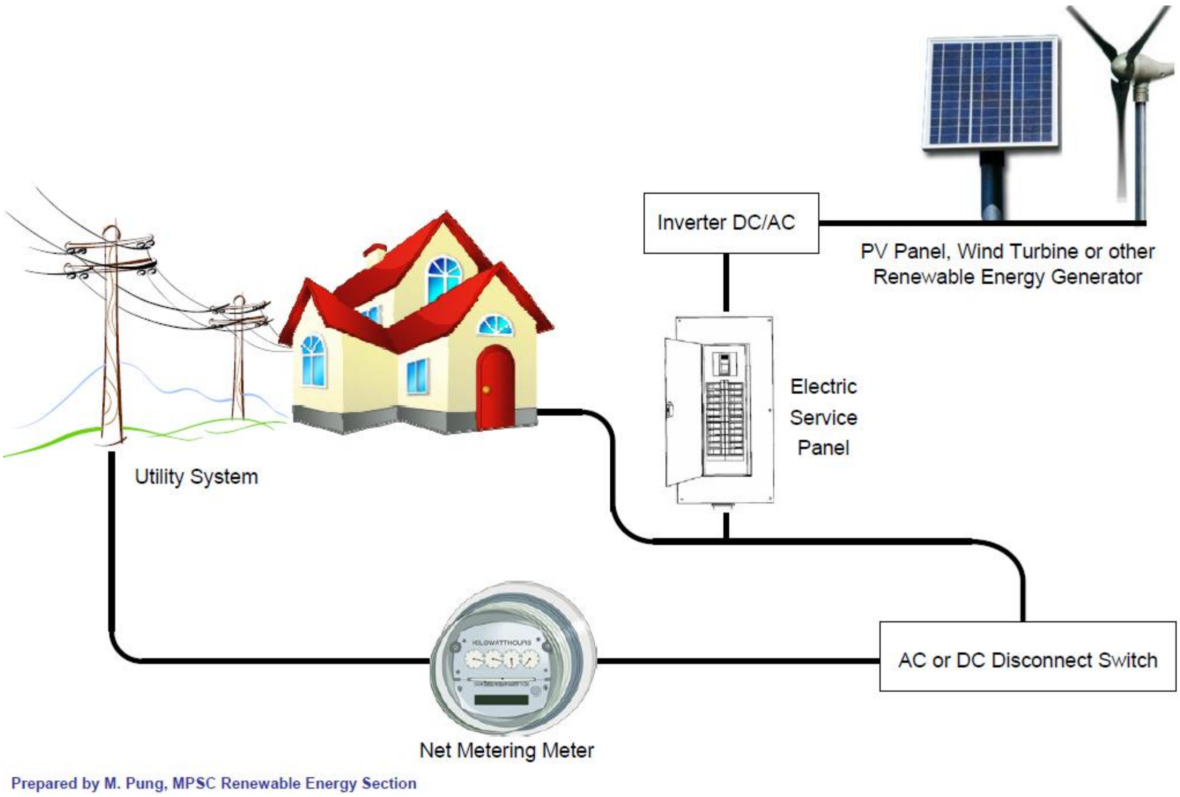

Illustration 3.a: Schematic diagram of net metering

Investing in renewable energy to meet a portion of own electricity requirements reduces the need for traditional electric power and the construction of costly power plants, while improving electricity reliability during times of high usage. Net metering programs serve as an important incentive for consumers who invest in renewable resources, such as solar or wind power, which can provide an option to lower utility bills [OCC 2009].

Countries are adopting a variation to the net metering policy. A sample net metering contains the following components[4]:

Net Metering Eligible Technologies

This usually contains a range of technologies the state can choose to sponsor, some of them are such as photovoltaics, wind energy, biomass, small hydroelectric.

Net Metering Applicable Sectors

This represents which of the participating sectors can enjoy this benefit. Residential, commercial, industrial, agricultural are some of the categories in this section.

Net Metering Limit on Size

This is the cap that each state can enforce based on the consumer sector and other local policies and rules.

Net Metering Treatment of Excess Net

This explains how the credit is going to happen to the consumer. Examples are:

- Carried over to next bill for the customer
- Granted to utility company

3.1 Average Cost for Each Renewable Energy Technology

The electricity generation costs from individual renewable energy sources are important in order to formulate the policy for net metering or feed in tariff. Those costs are technology as well as site specific. For a broad overview, table 3.1 shows typical costs of renewable energy generated electricity.

[4] Adopted from http://www.thankyousun.com/netmetering.htm

Table 3.1: Status of renewable energy technologies, characteristics & costs [REN 21 2010]

Technology	Typical Characteristics	Typical Energy Costs (U.S. cents/kilowatt-hour unless indicated otherwise)
Power Generation		
Large hydro	*Plant size*: 10 megawatts (MW)–18,000 MW	3–5
Small hydro	*Plant size*: 1–10 MW	5–12
On-shore wind	*Turbine size*: 1.5–3.5 MW *Blade diameter*: 60–100 meters	5–9
Off shore wind	*Turbine size*: 1.5–5 MW *Blade diameter*: 70–125 meters	10–14
Biomass power	*Plant size*: 1–20 MW	5–12
Geothermal power	*Plant size*: 1–100 MW; *Types*: binary, single- and double-flash, natural steam	4–7
Solar PV (module)	*Cell type and efficiency*: crystalline 12–18%; thin film 7–10%	---
Rooftop solar PV	*Peak capacity*: 2–5 kilowatts-peak	20–50
Utility-scale solar PV	*Peak capacity*: 200 kW to 100 MW	15–30
Concentrating solar thermal power (CSP)	*Plant size*: 50–500 MW (trough), 10–20 MW (tower); *Types*: trough, tower, dish	14–18 (trough)
Hot Water/Heating/Cooling		
Biomass heat	*Plant size*: 1–20 MW	1–6
Solar hot water/heating	*Size*: 2–5 m^2 (household); 20–200 m^2 (medium/multi-family); 0.5–2 MWth (large/district heating); *Types*: evacuated tube, flat-plate	2–20 (household) 1–15 (medium) 1–8 (large)
Geothermal heating/cooling	*Plant capacity*: 1–10 MW; *Types*: heat pumps, direct use, chillers	0.5–2
Biofuels		
Ethanol	*Feedstocks*: sugar cane, sugar beets, corn, cassava, sorghum, wheat (and cellulose in the future)	30–50 cents/liter (sugar) 60–80 cents/liter (corn) (gasoline equivalent)
Biodiesel	*Feedstocks*: soy, rapeseed, mustard seed, palm, jatropha, and waste vegetable oils	40–80 cents/liter (diesel equivalent)
Rural Energy		
Mini-hydro	*Plant capacity*: 100–1,000 kilowatts (kW)	5–12
Micro-hydro	*Plant capacity*: 1–100 kW	7–30
Pico-hydro	*Plant capacity*: 0.1–1 kW	20–40
Biogas digester	*Digester size*: 6–8 cubic meters	n/a
Biomass gasifier	*Size*: 20–5,000 kW	8–12
Small wind turbine	*Turbine size*: 3–100 kW	15–25
Household wind turbine	*Turbine size*: 0.1–3 kW	15–35
Village-scale mini-grid	*System size*: 10–1,000 kW	25–100
Solar home system	*System size*: 20–100 watts	40–60

Note: Costs are indicative economic costs, levelized, exclusive of subsidies or policy incentives. Typical energy costs are under best conditions, including system design, siting, and resource availability. Optimal conditions can yield lower costs, and less favorable conditions can yield substantially higher costs. Costs of off-grid hybrid power systems employing renewables depend strongly on system size, location, and associated items such as diesel backup and battery storage. Costs for solar PV vary by latitude and amount of solar insolation. *Source*: Data compiled from a variety of sources, including U.S. National Renewable Energy Laboratory, World Bank, International Energy Agency (IEA), and various IEA Implementing Agreements. Many current estimates are unpublished. No single published source provides a comprehensive or authoritative view on all costs. Changes in costs from the equivalent Table 1 in the *Renewables 2007 Global Status Report* reflect a combination of refined estimates, technology changes, and commercial market changes. For further costs reference, see World Bank/ESMAP, *Technical and Economic Assessment: Off Grid, Mini-Grid and Grid Electrification Technologies*, ESMAP Technical Paper 121/07 (Washington, DC: 2007); and IEA, *Deploying Renewables: Principles for Effective Policies* (Paris: OECD, 2008).

3.2 Net Metering and PV

One major problem with PV systems is that the supply of power from the system does not always correspond with the demand for power. If the power supplied exceeds the power required, the excess power may be wasted. There are two common ways to address this problem.

First, batteries may be added to the system to save the excess energy for later times when the demand for power exceeds the supply of the system. However, battery systems are large, expensive, and must be regularly maintained [Williamson, 2008].

The second way to address the problem is through the already briefly described solution known as net metering. Net metering promotes the use of on-site renewable power by ensuring that the full benefit of the system is realized. It allows individuals and businesses to be credited a fair value for excess power sent to the utility. When this occurs, the utility meter will reverse, crediting the consumer for the energy that was put onto the grid. This credit will show up on the consumer's bill as a reduction in the energy used.

In the event that the monthly power supplied back to the grid exceeds the power taken from the grid, the remaining power will be applied as a credit to the next month's bill (refund of cash is an alternative but not common). In many cases, the full amount of power supplied by the photovoltaic system will exceed the power requirement of the building. However, during night, low light, or high demand conditions, the power required by the building may exceed the power supplied by the system. Net metering allows excess power to be fed back into the power grid.

3.3 Net Metering in USA

Net metering has been described as "providing the most significant boost of any policy tool at any level of government to decentralize and 'green' American energy sources." Commonly referred to as the policy that lets your electric meter spin backwards, net metering programs are powerful, market-based, easy-to-administer incentives that states use to encourage energy independence.

As of September 2009, 42 states have statewide net metering programs - of varying quality. These programs are typically created through a commission rule, a state law, or a combination of the two. In addition, Washington D.C. has its own program, and voluntary net-metering programs exist in three states. These net metering rules establish the process for crediting owners of customer-sited, grid connected distributed generators for excess electricity fed into the grid [NNEC 2009].

3.3.1 PV Systems and Net Metering

Under federal law, utilities must allow independent power producers to be interconnected with the utility grid, and utilities must purchase any excess electricity they generate[5]. Many states have gone beyond the minimum requirements of the federal law by allowing net metering for customers with PV systems. With net metering, the customer's electric meter will run backward when the solar electric system produces more power than is needed to operate the home or business at that time. An approved, utility-grade inverter converts the DC-power from the PV modules into AC-power that exactly matches the voltage and frequency of the electricity flowing in the utility line; the system must also meet the utility's safety and power-quality requirements. The excess electricity is then fed into the utility grid and sold to the utility at the retail rate.

In the event of a power outage, safety switches in the inverter automatically disconnect the PV system from the line. This safety disconnect protects utility repair personnel from being shocked by electricity flowing from the PV array into what they would expect to be a "dead" utility line.

[5] Adopted from http://www1.eere.energy.gov/solar/net_metering.html

At the end of the month, if the customer has generated more electricity than that used, the utility credits the net kilowatt-hours produced at the wholesale power rate. But if the customer uses more electricity than the PV system generates, the customer pays the difference. The billing period for net metering may be either monthly or annually. In some states, the excess generation credits at the end of each billing period are carried over to the next billing period for up to a year.

Net metering allows homeowners who are not home when their systems are producing electricity to still receive the full value of that electricity without having to install a battery storage system. Essentially, the power grid acts as the customer's battery backup, which saves the customer the added expense of purchasing and maintaining a battery system.

Generally, the preferred method of accounting for the electricity under net metering is with a single, reversible meter. An alternative is dual metering, in which customers or their utility purchase and install two non-reversing meters that measure electrical flow in each direction. This adds significant expense to a PV system, however. The current trend around the country is toward a single, reversible meter.

Some utilities are opposed to net metering because they believe it may have a negative financial impact on them. However, a number of studies have shown that net metering can benefit utilities. These benefits include reductions in meter hardware and interconnection costs, as well as in meter reading and billing costs. Grid connected PV systems can also help utilities avoid the cost of additional power generation, increase the reliability and quality of electricity in the grid, and produce power at times of peak usage, when utility generation costs are higher and they often need the extra power.

3.3.2 Best Practices in Net Metering

The following points have been mentioned as “best practices” in net metering based on US experiences [NNEC 2009]:

- Allow net metering system size limits to cover large commercial and industrial customers’ loads; systems at the 2 MW level are no longer uncommon.
- Do not arbitrarily limit net metering as a percent of a utility’s peak demand.
- Allow monthly carryover of excess electricity at the utility’s full retail rate.
- Specify that customer-sited generators retain all renewable energy credits for energy they produce.
- Allow all renewable technologies to net meter.
- Allow all customer classes to net meter.
- Protect customer-sited generators from unnecessary and burdensome red tape and special fees.
- Apply net metering standards to all utilities in the state, so customers and installers fully understand the policy, regardless of service territory.

3.3.3 Best Practices in Interconnection Procedures

The utilities (or the authorities) regulate the process whereby renewable energy systems are connected to the electric distribution grid. These policies, commonly known as interconnection procedures, seek to maintain the stability of the grid and the safety of those who use and maintain it. However, if not designed fairly or implemented properly, these policies can pose a barrier to the development of customer-sited renewable energy and other forms of distributed generators (DG) [NNEC 2009].

Customers who seek to generate their own electricity with a grid connected PV system, a wind turbine or another form of DG must first apply to interconnect the system. In some cases, the interconnection process is so lengthy, arduous and/or expensive that it thwarts the development of customer-sited DG altogether.

Historically, this stymieing of customer investment in clean energy resources has been all too familiar to many would-be owners of small DG systems. Fortunately, a significant number of states have simplified and streamlined the interconnection process for customer-sited DG systems. Customers considering grid-tied renewables in states with well-designed interconnection procedures are able to take advantage of a process that is transparent and equitable, and often involves separate tiers of analysis depending on a system's size and complexity. These tiers usually contain a "fast track" for interconnecting relatively simple, certified systems, such as PV systems up to 2 MW in capacity.

[IREC 2009] mentions the following provisions:

- All electricity providers shall offer net metering to customer-generators with renewable energy generation that is interconnected and operated in parallel pursuant to the interconnection rules, provided, however, that the rated capacity of the renewable energy generation does not exceed the customer-generator's service entrance capacity[6].

- All electricity providers shall make net metering available to customer-generators in a timely manner and on a first-come, first-served basis. An electricity provider shall not limit the cumulative, aggregate generating capacity of net-metered systems in any manner[7].

- Each electricity provider shall develop a net metering tariff that provides for customer generators to be credited in kWh at a ratio of 1:1 for any excess production of their generating facility that exceeds the Customer-generator's on site consumption of kWh in the billing period.

- The electricity provider shall carry over any excess kWh credits earned by a customer generator and apply those credits to subsequent billing periods to offset the customer generator's consumption in those billing periods until all credits are used[8]. Any excess

[6] Some states do not impose limitations on the size of a renewable energy generating system that may be net metered. For states that impose system size limitations, such limits vary from as low as 25 kW to as high as 80 MW; however, most states appear to be coalescing at a 2 MW cap.

[7] Some states cap the total amount of aggregate renewable energy generation that can be net metered for a particular electricity provider. Most commonly, aggregate enrollment caps are expressed as a percentage of an electricity provider's peak demand based on the aggregate of nameplate capacity of the generation systems (though it should be noted that capacity calculations are not standardized in their methodology across or even within states). Such percentages can vary from as low as 0.1 % to as high as 20 %.

[8] Different US states have explored various approaches regarding the treatment of annual net excess generation. The most common approaches allow an electricity provider either to retain the net excess generation free of charge or to provide payment for annual net excess generation at the electricity provider's avoided cost. However, more novel approaches have also been taken. At least one state directs annual net excess generation to a state low-

kWh credits shall not reduce any fixed monthly customer charges imposed by the electricity provider.

- An electricity provider shall offer a customer generator the choice of a time differentiated energy tariff rate or a non-time-differentiated energy tariff rate, if the electricity provider offers the choice to customers in the same rate class as the customer generator. If a customer generator uses a meter and retail billing arrangement that has time differentiated rates, the electricity provider shall net any excess production against on-site consumption within the same time-of-use period in the billing period. Excess monthly kWh credits shall be based on the ratio representing the difference in retail rates for each time of use period.

- If a customer generator terminates service with the electricity provider or switches electricity providers, the electricity provider is not required to provide compensation to the customer generator for any outstanding excess kWh credits.

- A customer generator facility used for net metering shall be equipped with metering equipment that can measure the flow of electricity in both directions. In USA, for customer generator facilities less than 25 kW in rated capacity, this shall be accomplished through the use of a single, bi-directional electric revenue meter that has only a single register for billing purposes[9].

- A customer generator may choose to use an existing electric revenue meter if the following criteria are met:

    - The meter is capable of measuring the flow of electricity both into and out of the customer generator's facility; and

    - The meter is accurate with a degree of accuracy that the electricity provider requires when measuring electricity flowing from the customer generator facility tothe electric distribution system.

- If a customer generator's existing revenue meter does not meet the requirements of mentioned in the point before, the electricity provider shall install and maintain a new revenue meter for the customer generator at the electricity provider's expense. Any subsequent revenue meter change necessitated by the customer generator, whether because of a decision to stop net metering or for any other reason, shall be paid for by the customer generator.

- The electricity provider shall not require more than one meter per customer generator. However, an additional meter may be installed under either of the following circumstances:

    - The electricity provider may install an additional meter at its own expense if the customer generator provides written consent; or

income assistance program. These rules provide for perpetual rollover of excess generation credits. This approach has been adopted in a number of states and has been adopted as a best practice in these rules. This approach allows for maximum flexibility in sizing a system while assuring a minimum level of regulatory and administrative burden.

[9] This provision may need to be modified in states that are implementing advanced metering infrastructure (AMI) and require residential and small commercial customers to have AMI meters; provided, however, that any such meter does not result in an additional cost to a Customer-generator beyond the cost that would be paid in the absence of a customer having renewable energy generation.

  - The customer generator may request that the electricity provider install a meter, in addition to the revenue meter addressed in point 8 above, at the customer generator's expense. In such a case, electricity provider shall charge the customer generator no more than the actual cost of the meter and its installation.

- A customer generator owns the Renewable Energy Credits (RECs) associated with the electricity it generates, unless such RECs were explicitly contracted for through a separate transaction independent of any net metering or interconnection tariff or contract.

- An electricity provider shall provide to customer generators electric service at non discriminatory rates that are identical, with respect to rate structure, retail rate components and any monthly charges, to the rates that a customer generator would be charged if not a customer generator, including choice of retail tariff schedules.

- An electricity provider shall not charge a customer generator any fee or charge; or require additional equipment, insurance or any other requirement not specifically authorized under this sub-section or the interconnection rules, unless the fee, charge or other requirement would apply to other similarly situated customers who are not customer generators.

- Each electricity provider shall submit an annual net metering report to the regulatory commission (of federal states USA). The report shall be submitted by certain date of each year, and shall include the following information for the previous year:

  - The total number of net metered customer generator facilities, by resource type;

  - The total rated generating capacity of net metered customer generator facilities, by resource type;

  - The total number of kWh received from net metered customer generators; and

  - The total estimated amount of kWh produced by net metered customer generators, provided that this estimate does not require additional metering equipment.

- If a customer generator’s renewable energy generation system has been approved for interconnection under the interconnection rules, the electricity provider shall not require a customer generator to test or perform maintenance on the customer generator's system except in the case of any testing or maintenance recommended by the system manufacturer.

- An electricity provider shall have the right to inspect a customer generator's system during reasonable hours and with reasonable prior notice to the customer generator. If an electricity provider finds that the customer generator's system is not in compliance with the requirements of the interconnection rules and the requirements applicable standards, and non-compliance adversely affects the safety or reliability of the electricity provider's facilities or of other customer's facilities, the electricity provider may require the customer generator to disconnect the facility until compliance is achieved.

- Each electricity provider shall make net metering applications available through the electricity provider's website. In jurisdictions where wet signatures are not required, electricity providers shall accept applications online.

For customer generators participating in meter aggregation, the following provisions are suggested:

- For the purpose of measuring electricity usage under these net metering rules, an electricity provider must, upon request from a customer generator, aggregate for billing purposes a meter to which the net metering facility is physically attached (designated meter) with one or more meters (additional meter) in the manner set out in this subsection. This rule is mandatory upon the electricity provider only when:
    - The additional meter is located on the customer generator's contiguous property;
    - The additional meter is used to measure only electricity used for the customer generator's requirements
- A customer generator must give at least 30 days notice to the electricity provider to request that additional meters be included in meter aggregation. The specific meters must be identified at the time of such request. In the event that more than one additional meter is identified, the customer generator must designate the rank order for the additional meters to which net metering credits are to be applied.
- The net metering credits will apply only to charges that use kWh as the billing determinant. All other charges applicable to each meter account will be billed to the customer generator.
- If in a monthly billing period, the net metering facility supplies more electricity to the electricity provider than the energy usage recorded by the customer generator's designated meter, the electricity provider will apply credits to additional meters in the rank order provided by the customer generator, and any remaining credits after doing so will be rolled over to the designated meter for use during the subsequent billing period.
- Customer generators participating in meter aggregation do not have to have all meters on the same rate schedule.

To summarize the following points have been mentioned as “best practices” in interconnection based on US experiences [NNEC 2009]:

- Set fair fees that are proportional to a project’s size.
- Cover all generation types (by sources).
- Screen applications by degree of complexity and adopt plug-and-play rules for residential- scale systems and expedited procedures for other systems.
- Ensure that policies are transparent, uniform, detailed and public.
- Prohibit requirements for extraneous devices, such as redundant disconnect switches, and do not require additional insurance.
- Apply existing relevant technical standards.
- Process applications quickly; a determination should occur within a few days.
- Standardize and simplify forms.

3.3.4 Utilities Concerns of Net Metering

The following concerns sometimes are mentioned by utilities [Morrison 2010]:

- Net metering policies require utilities to pay consumers the retail price for wholesale power. The retail rate utilities charge includes not only the marginal cost of power, but also recovers costs incurred by utilities' for transmission, distribution, generating capacity, and other utility services not provided by the customer-generator.

- The policies require utilities to pay high costs for what is often low-value power. Power from wind and photovoltaic systems is intermittent, cannot be scheduled or dispatched reliably to meet system requirements. Even those forms of customer generation that could technically be dispatched at times when utilities need the power do not need to enter into operating agreements with utilities in order to obtain net metering under state net metering mandates.

  That PV, wind and other decentralized power generation facilities are not necessarily of low value but could prevent e.g. from grid extension is discussed in section 4.

- Net meters allow customers to under-pay the fixed costs they impose on the system. A utility has to install sufficient facilities to meet the peak requirement [Author comment: peak requirement could be decreased!] of the consumer and recover the costs of those facilities through a kWh charge. When the net meter rolls backwards, it understates the total energy used by the consumer, and thus understates the consumer's impact on the fixed costs of the system. It also understates the consumer's total share of other fixed charges borne by all consumers such as taxes, stranded costs, transition costs, and public benefits charges.

- Net meters can also be deliberately or inadvertently gamed. Consumers can take power from the system at peak times when it costs the utility the most to provide it, and then roll their meters backwards by generating power at non-peak times when the utility has little need for it. That is a particular risk, for example, with gas and diesel fueled units that can be operated on demand. [Author comment: that should not be done and is not the case with intermittent renewable electricity generation!]

4 Perspectives of net-metering for PV systems in Brazil

A prerequisite that net-metering could become superior to feed-in-tariffs is that electricity generation costs is or is becoming cheaper or at least equal to the end-user electricity prize.

In this section electricity generation prizes of PV systems under Brazilian climate conditions together with the development of end-user electricity is analyzed.

4.1 Solar Radiation Resources in Brazil

Electricity generated from PV strongly depends on solar resources. Illustration 4.1.a shows the solar radiation map for Brazil[10].

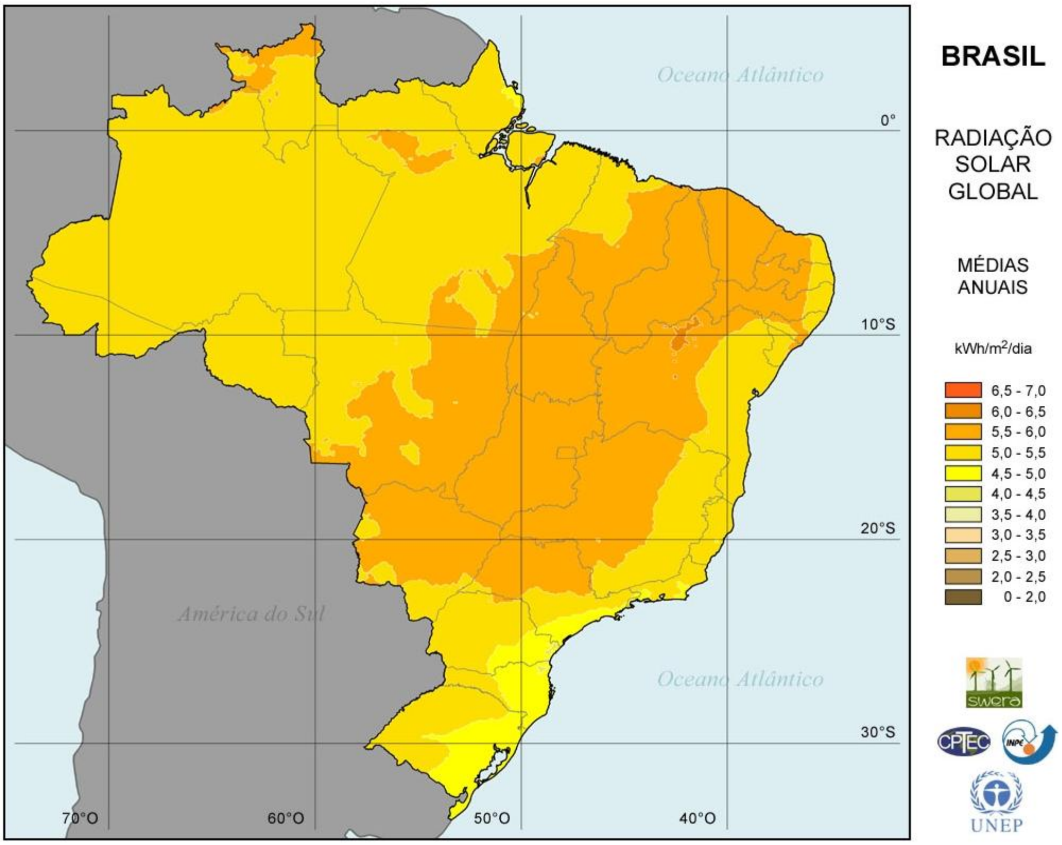

Illustration 4.1.a: Solar radiation map of Brazil

The global radiation data for different cities (in different geographical locations) in Brazil has been taken from Meteonorm and they are as follows:

[10] Adopted from http://www.solarpaces.org/News/Projects/Brazil.htm

Table 4.1.a: Global radiation data for Brazilian cities taken from Meteonorm

Cities	Global radiation on horizontal surface (kWh/m^{2}a)
Belem	1842
Brasilia	1797
Curitiba	1461
Fortaleza	2029
Recife	2225
Rio de Janeiro	1691
Sao Paolo	1446

These values are used to calculate the grid parity years for Brazil. The electricity generation price for a kWh using solar PV systems could be taken as a base for developing the PV system promotion policy.

A brief economic analysis has been carried out to find out the PV electricity generation price in different geographic locations in Brazil. PV module price is assumed to be decreased in the coming years driven by experience curve effects.

4.2 Experience Curve for Solar PV

Experience curves describe how cost declines with cumulative production, where cumulative production is used as an approximation for the accumulated experience in producing and employing a technology. PV modules experience curve learning rate for the period to come will follow by 20 % (meaning a progress ratio of 80 %) [Schaeffer et al, 2004].

The learning at PV module level makes no distinction between global and local learning, since most of the module manufacturing is done by internationally operating companies and there is extensive exchange of scientific and technological information on module technology. This is why an experience curve for world module price has been extrapolated and the values are used in calculations for Brazil in this report.

In illustrations 4.2.a and 4.2.b experience curves are plotted for different progress ratios (75 %, 80 %, 85 % and 90 %) and different annual growth rates for PV installations worldwide. For the calculations of economic analysis, a module price decrease at progress ratio of 80 % has been used.

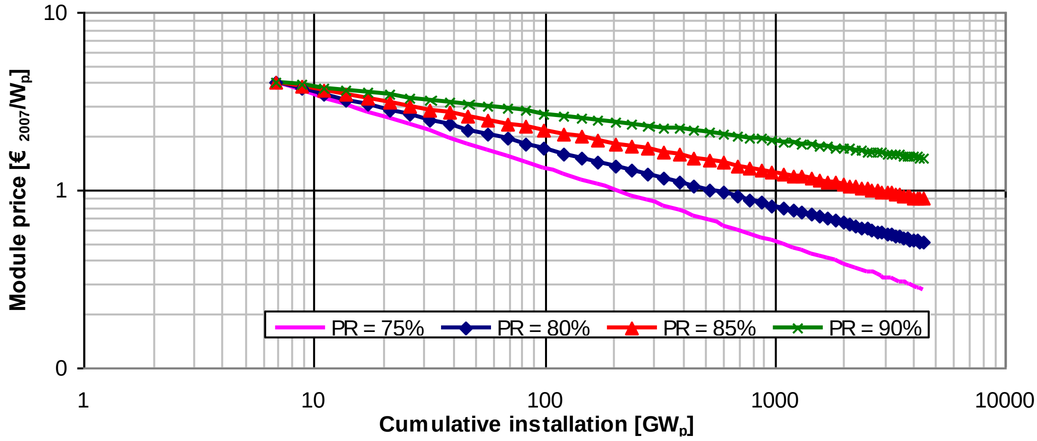

Illustration 4.2.a: PV experience curve for world module price, 2006-2060 [Bhandari, 2010]

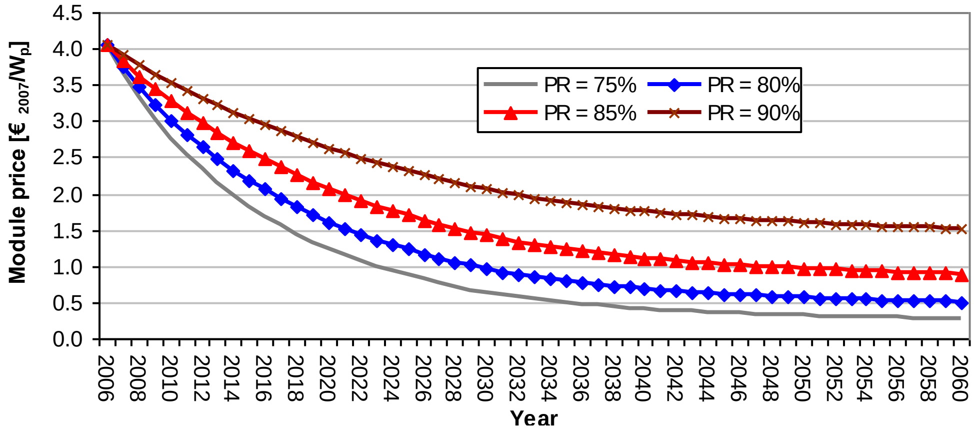

Illustration 4.2.b: Projected world module price for different progress ratio [Bhandari, 2010]

4.3 Economic Analysis

The analysis is based on the assumptions given in table 4.3.a.

PV system is considered to be installed by households and a capacity of 3 kW_p. The balance of system (everything else than moduels) cost used in this study is 30 % of total module costs. BOS replacement cost factor is supposed to be 70 % of the BOS costs assuming that all BOS components need not to be replaced (e.g. system planning and installation costs, PV module support structures, etc.). Cost for land is neglected with the assumption that the PV power plant will be installed at home premises, mainly on roof top. Other local factors such as value added taxes or any existing subsidy schemes that influence the investment in PV systems are excluded. No salvage value or disposal cost after system life time is over has been considered.

Table 4.3.a: Default values – grid connected solar PV system

Description	Symbol	Unit	Value
Module price	C_m	€/kW$_p$	3033[11]
BOS cost factor	k_{bos}	%	30
BOS replacement cost factor	k_{bosrpl}	%	70
BOS component life time	N_r	year	12
Interest rate	i	%	6
Discounting rate[a]	d	%	4
Variable cost factor[b]	k_v	%	1
Peak power	P_{peak}	kW$_p$	3
Annual degradation of energy yield	s	%	1
Performance ratio	Q	%	75

[a] discounting rate has been used to consider the opportunity cost of an alternative low risk investment (e.g. bank deposit). In other words, the money at hand today has given a higher value than the same amount in future.

[b] variable cost factor is a portion of initial investment and this expense will be needed annually for module cleaning, maintenance of structure and cables, insurance, etc.

4.4 Grid Parity

Grid parity explains the time point when a kWh electricity generation cost using solar PV becomes equal to a kWh electricity price from grid. PV electricity generation cost per kWh has been calculated by dividing the total system cost by cumulative electricity yield from PV system throughout its life time. Grid electricity has two different prices, one at wholesale market and one at household consumer market (i.e. end user price). In the following sections the end user electricity price has been used to calculate the grid parity.

The end user electricity price is assumed to vary between 10 €ct/kWh and 25 €ct/kWh in different places within Brazil. Also the global radiation values between 1200 kWh/m^2 and 2400 kWh/m^2 has been used in the calculations.

The results are shown for the following cases:

[11] The price is taken from the experience curve anylysis results (figure 4)

Case 1

Global radiation = 1200 kWh/m^2.year and annual electricity price growth rate = 2 %

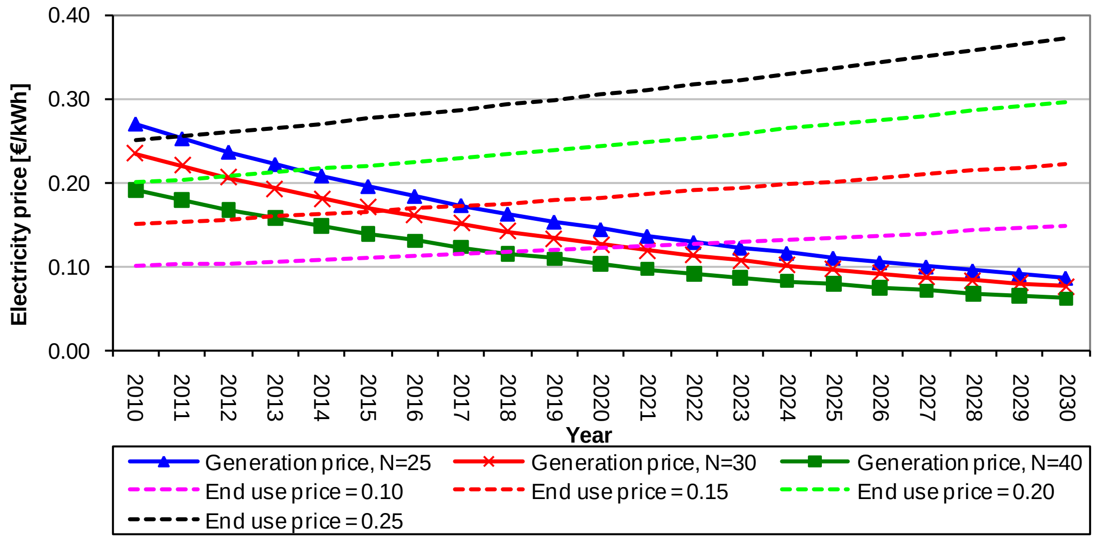

Illustration 4.4.a: Grid parity years – case 1

Case 2

Global radiation = 1200 kWh/m^2.year and Price growth rate = 4 %

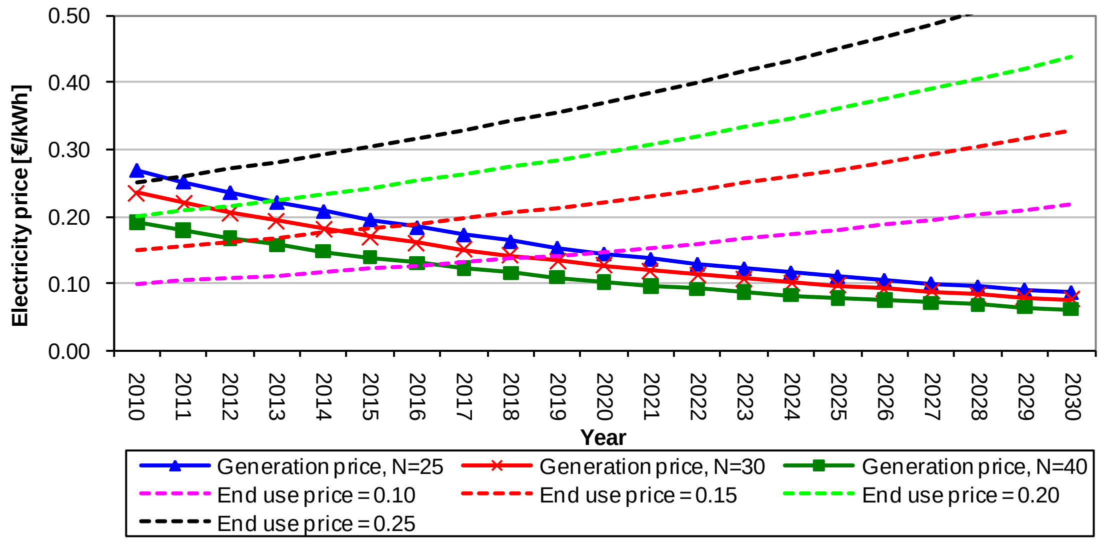

Illustration 4.4.b: Grid parity years – case 2

Case 3

Global radiation = 1500 kWh/m2.year and Price growth rate = 2%

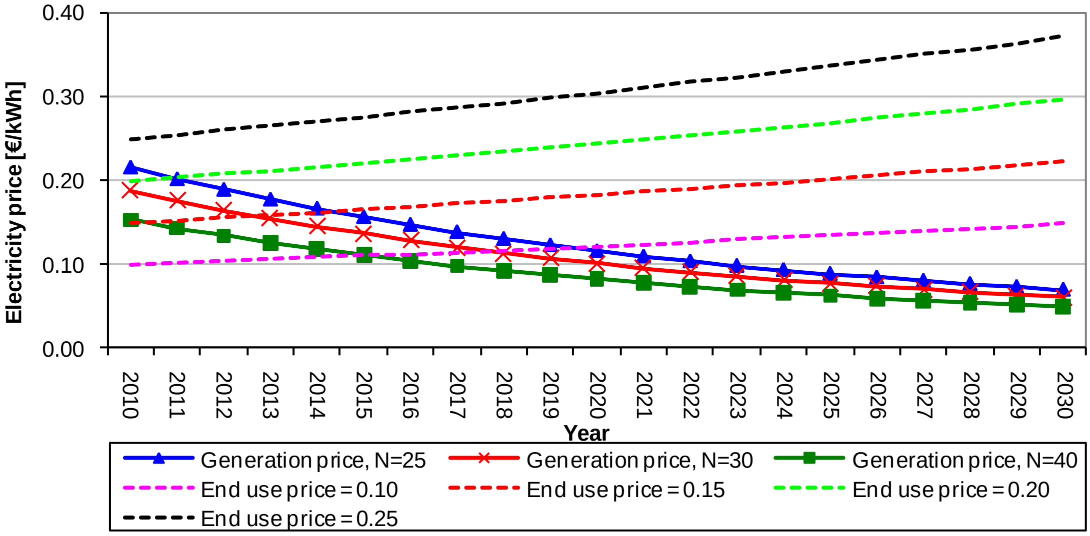

Illustration 4.4.c: Grid parity years – case 3

Case 4

Global radiation = 1500 kWh/m^2.year and Price growth rate = 4 %

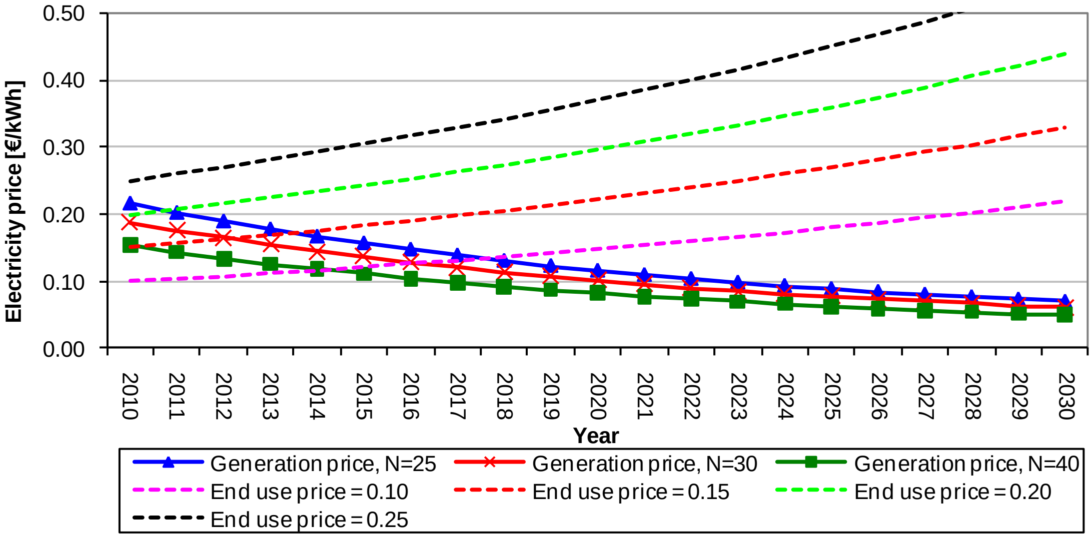

Illustration 4.4.d: Grid parity years – case 4

Case 5

Global radiation = 1800 kWh/m^2.year and Price growth rate = 2 %

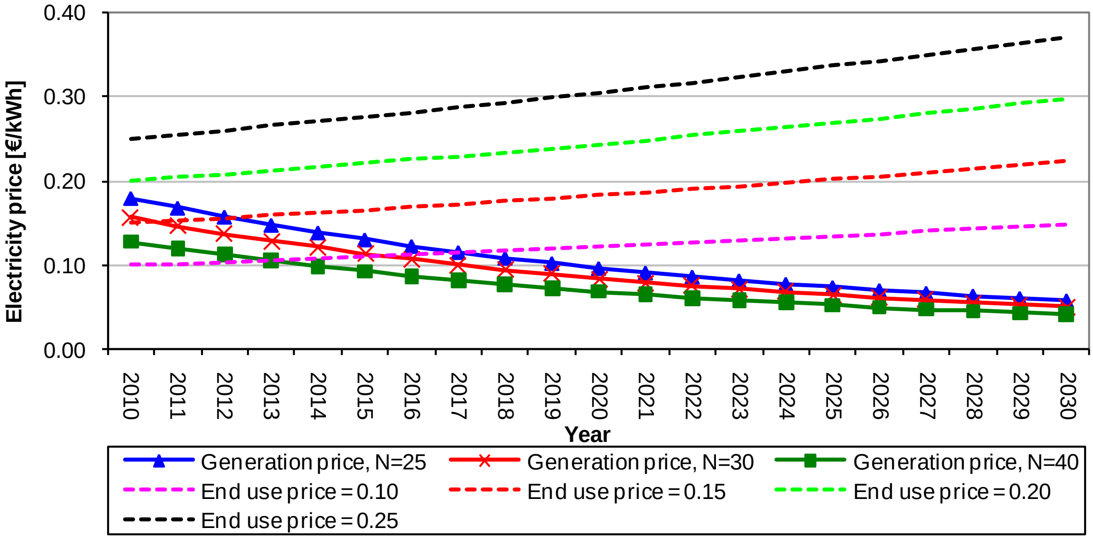

Illustration 4.4.e: Grid parity years – case 5

Case 6

Global radiation = 1800 kWh/m^2.year and Price growth rate = 4 %

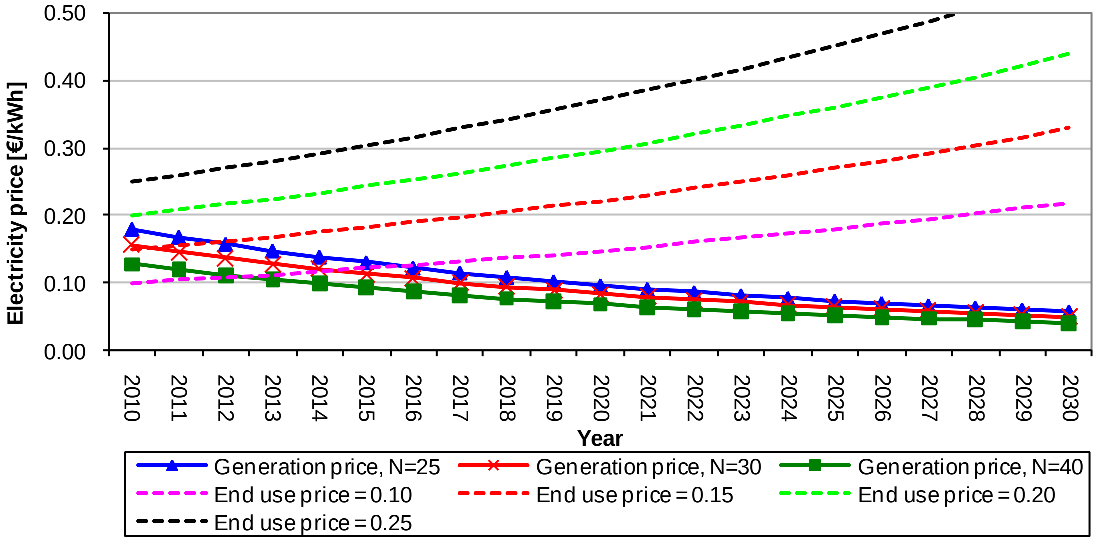

Illustration 4.4.f: Grid parity years – case 6

Case 7

Global radiation = 2100 kWh/m^2.year and Price growth rate = 2 %

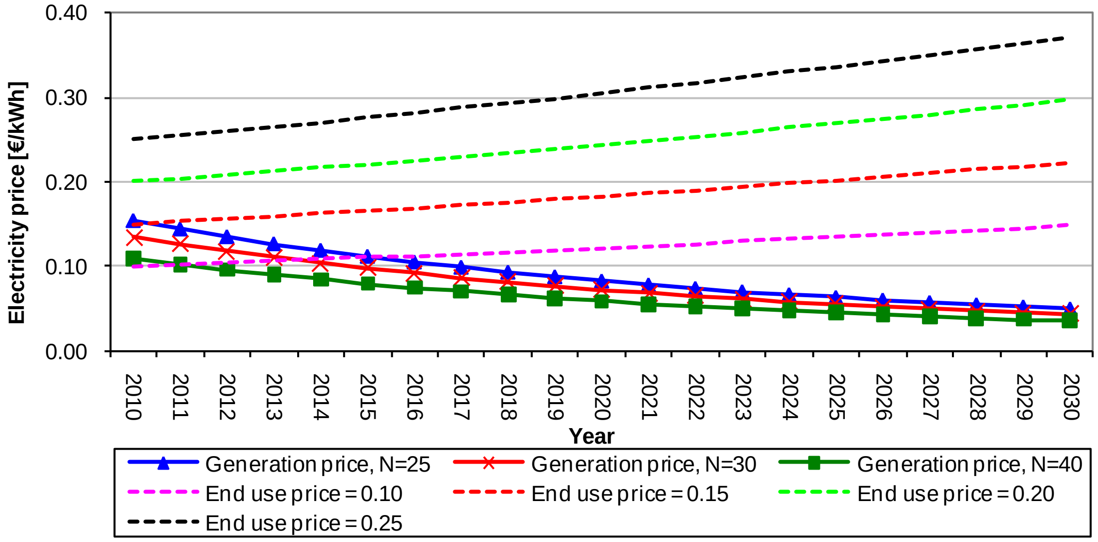

Illustration 4.4.g: Grid parity years – case 7

Case 8

Global radiation = 2100 kWh/m^2.year and Price growth rate = 4 %

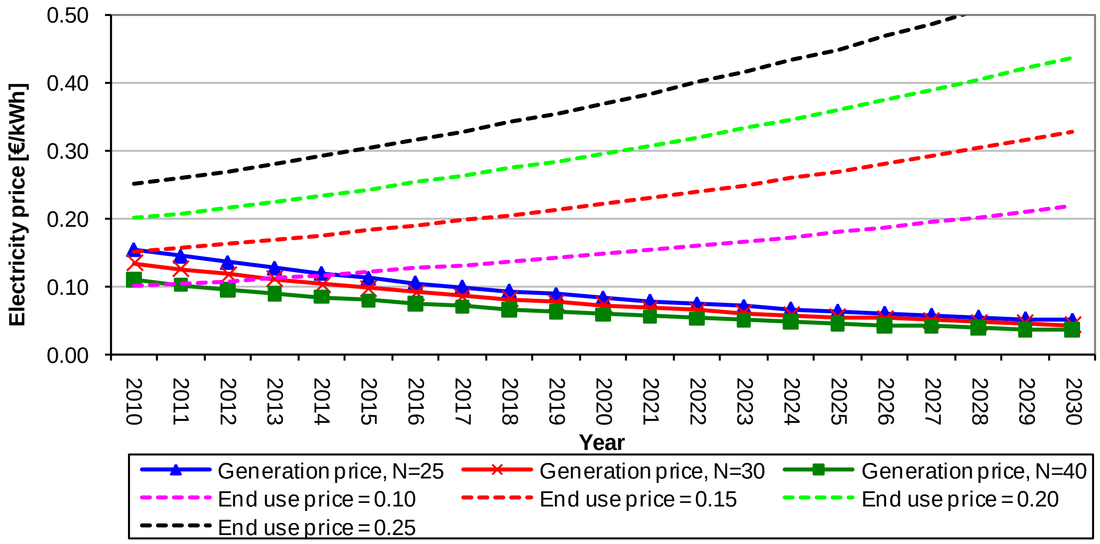

Illustration 4.4.h 1: Grid parity years – case 8

Case 9

Global radiation = 2400 kWh/m^2.year and Price growth rate = 2 %

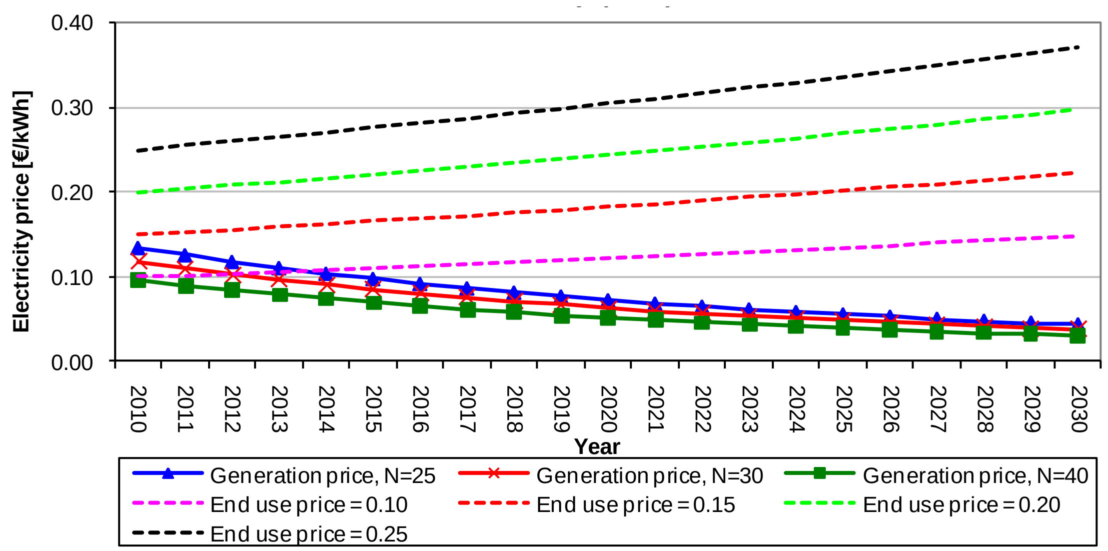

Illustration 4.4.i: Grid parity years – case 9

Case 10

Global radiation = 2400 kWh/m^2.year and Price growth rate = 4 %

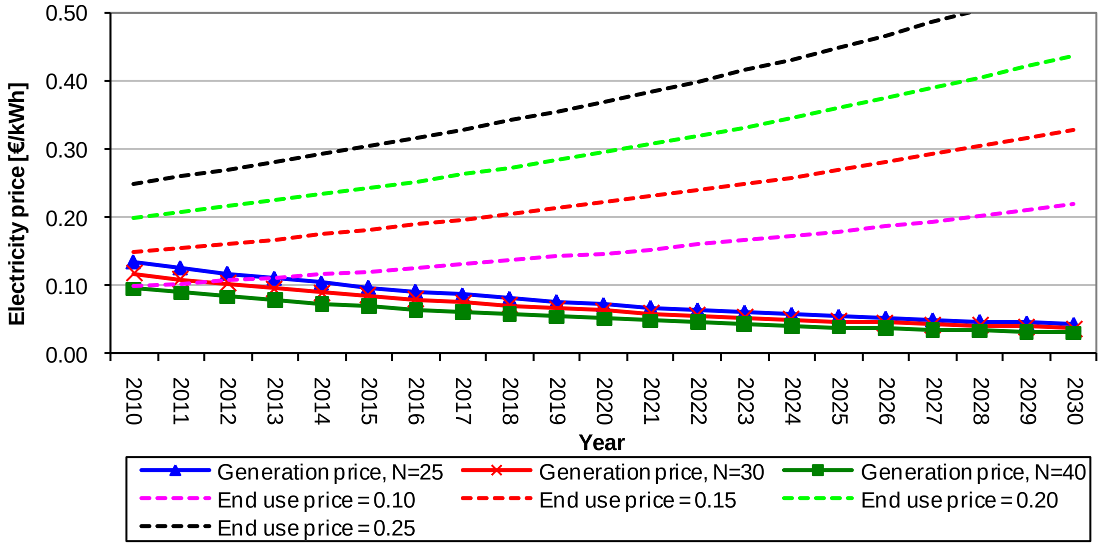

Illustration 4.4.j: Grid parity years – case 10

Case 11

The effect of different bank interest rate (0 % until 15 %) on the grid parity year has been shown in this case. The system life time of only 25 years has been considered in this case. As illustrated in the graph, the occurrence of grid parity is very much dependent on bank interest rate in the investment.

Global radiation = 2000 kWh/m^2.year and Price growth rate = 2 %

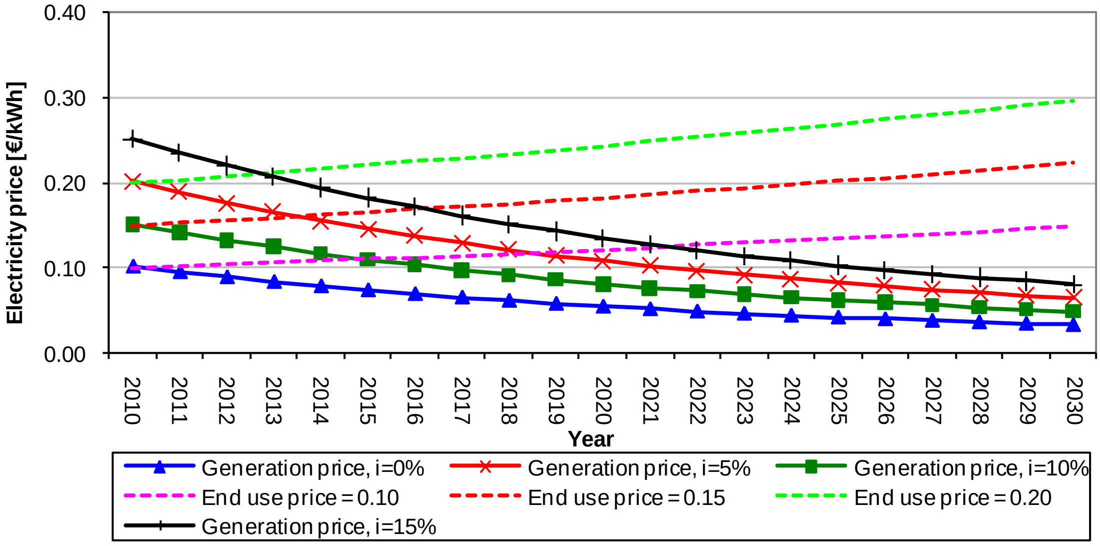

Illustration 4.4.k: Grid parity years – case 11

In all the cases discussed above, the module price for c-Si type modules has been assumed to be about 3022 €/kWp. However, in recent days the module price has been decreasing at faster pace and prices could be below this value in some markets. The cheaper thin film modules are not analyzed in this case. At present, the thin film module price is in the range of 1500 €/kWp. Therefore, choosing such modules could eventually make the PV system better competitive in the electricity market.

5 Impact of decentralized generation on load curves and distribution infrastructure

The German government announced the target to reorganize electricity production in a way that in the year 2050 80 % of the electricity generated is done by renewable energy sources (today about 16 %) [Energiekonzept 2010]. This will come along with new demands for the grid infrastructure and the question is how current infrastructure is suited for future challenges.

Illustration 5.a shows the power flows within traditional electricity supplies. Power plants have big rated powers, feed into the high voltage transmission grid and are built either close to load centers or where primary energy resources are available or easy to transport. Power flow is always top to bottom. Power flow is always from the power plants at highest voltage level down to the consumers connected to low and medium voltage level.

In future electricity supply there still will be a big amount of generation capacity feeding to the high voltage grid but often located in other places, e.g. offshore where wind conditions are excellent. That goes along with the erection of new transmission capacity, see e.g. [dena 2004], [Valov 2009]. But in addition generation capacity is also connected to the medium voltage level (mainly wind parks) that could lead to a reversed power flow. And finally, an increasing amount of decentralized capacity is connected to the low voltage level, especially photovoltaic power generators and small combined heat and power systems leading to all kind of power flow situations (illustration 5.b).

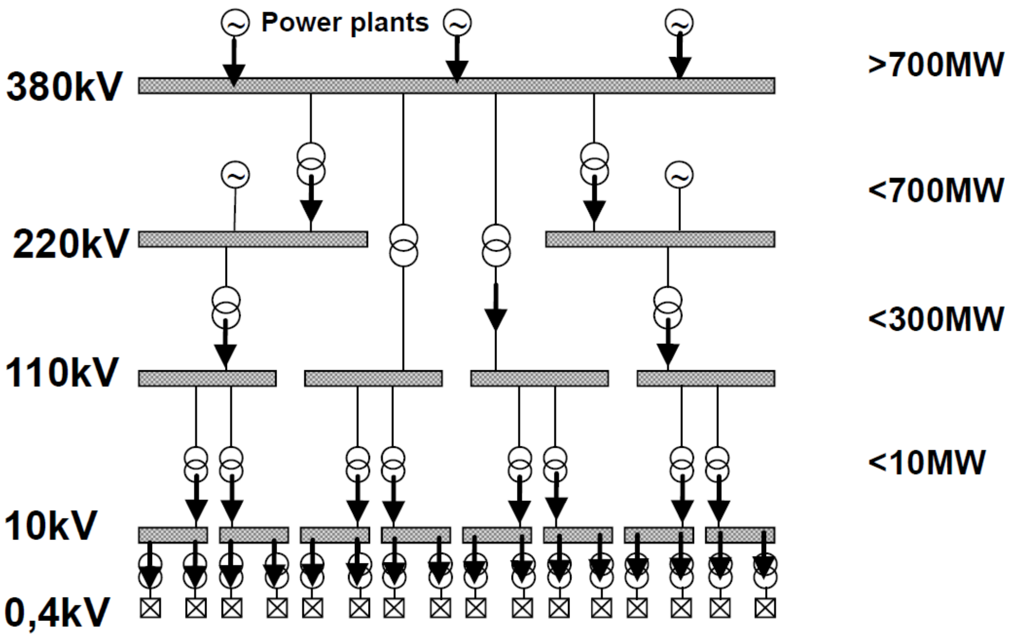

Illustration 5.a: Traditional electricity transmission and distribution grid structure with indicated power flow

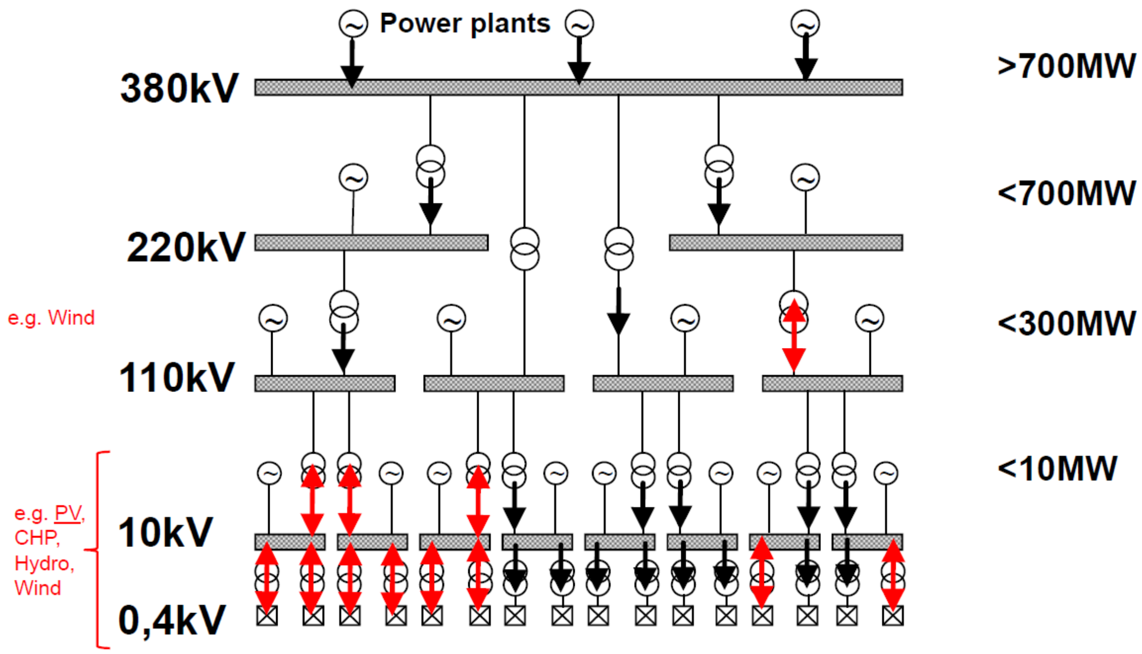

Illustration 5.b: E*lectricity transmission and distribution grid structure with high shares on distributed generation*

The question to answer is whether the existing grid is capable to cope with the planned electricity supply structure or if it is not? As mentioned before due to new installation sites like offshore wind parks there is a necessity to build new transmission lines. But this is not a mayor economic factor [dena 2004]. The German public electricity grid has a length of 1.8 million kilometers and only about 6 % counts for the high voltage level. The mayor part is medium voltage grid (27 %) and the low voltage distribution grid with 67 %. It is essential that low and medium voltage grids can cope with their new duties. Can they?

Comparing illustrations 5.a and 5b it is clear that every Watt generated in decentralized – meaning where the loads are – unburdens the grid assets. That means including decentralized generation results in lower loading of high voltage transmission lines, medium and low voltage distribution lines and all transformers in-between. That has several effects:

- Lower loading of transmission and distribution equipment results in lower power losses and therefore in lower costs for grid operators (to cover losses is in the responsibility of grid operators).
- In countries and regions with a high growth rate in electricity consumption there is a need for new (centralized) power generation capacity and also for higher capacities in transmission lines and transformers. Depending on the degree of decentralized generation application grid extension both can be slowed down and minimized or even be avoided (at least when decentralized generation contributes to peak power demand).
- Private capital is motivated to contribute to the power system extension

Generally, decentralized power generation unburdens the system!

Nevertheless, there might be other problems with decentralized generation and feeding-in to the distribution grids. They will be analyzed in the next sections and exemplary discussed with the German context.

5.1 Current situation and problems related to decentralized generation in German distribution grids

Within the last two years in television and newspaper announcements regularly one could find contributions that due to the renewable energy act so many photovoltaic systems have been installed that the public grid has arrived at its maximum intake capacity. This is far away from being reality. In illustration 5.1.a the installed capacity in the end of 2009 with a total installed PV capacity of almost 10 GW_p is shown. That is an equivalent of 121 Watt per capita. The leading state in Germany is Bavaria with an installed capacity of 311 Watt per capita and a fraction of more than 3 % of the electricity demand.

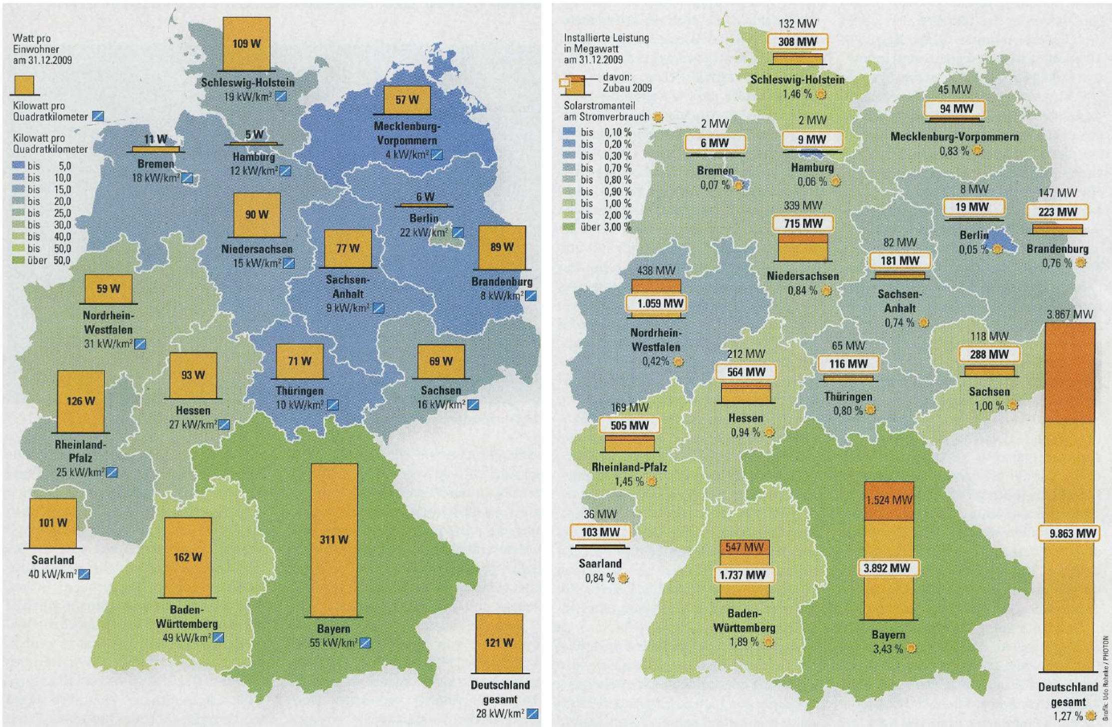

Illustration 5.1.a: Left: Installed PV module capacity per capita and per km². Right: Total installed capacity and in 2009 new installed capacity (orange block), percentage of PV on electricity demand [Photon 2010]

Later in the report it will be shown that this cannot cause problems at all. Even when targets of an installed capacity 30 GW or 50 GW as indicated in some energy scenarios will not cause mayor problems. At least it would not cause problems when the capacity would be distributed equally.

Nevertheless, in some special situations the capacity is already exceeded. An equal distribution does not cope with reality. Especially in rural areas with weak grids and low energy consumption and population densities photovoltaics has boomed a lot in the years ago. In illustration 5.1.b Nenning shows an extreme situation of such an area dominated by farm houses with large roof surfaces. Buildings are located far away from each other and almost all houses contain larger photovoltaic plants (13,5 kW_p, 20 kW_p and 38,7 kW_p) or other distributed electricity generation (biogas combined heat and power units with an overall capacity of 152 kW). In this case (and various others in rural areas) grid infrastructure was overloaded and the grid needed to be extended.

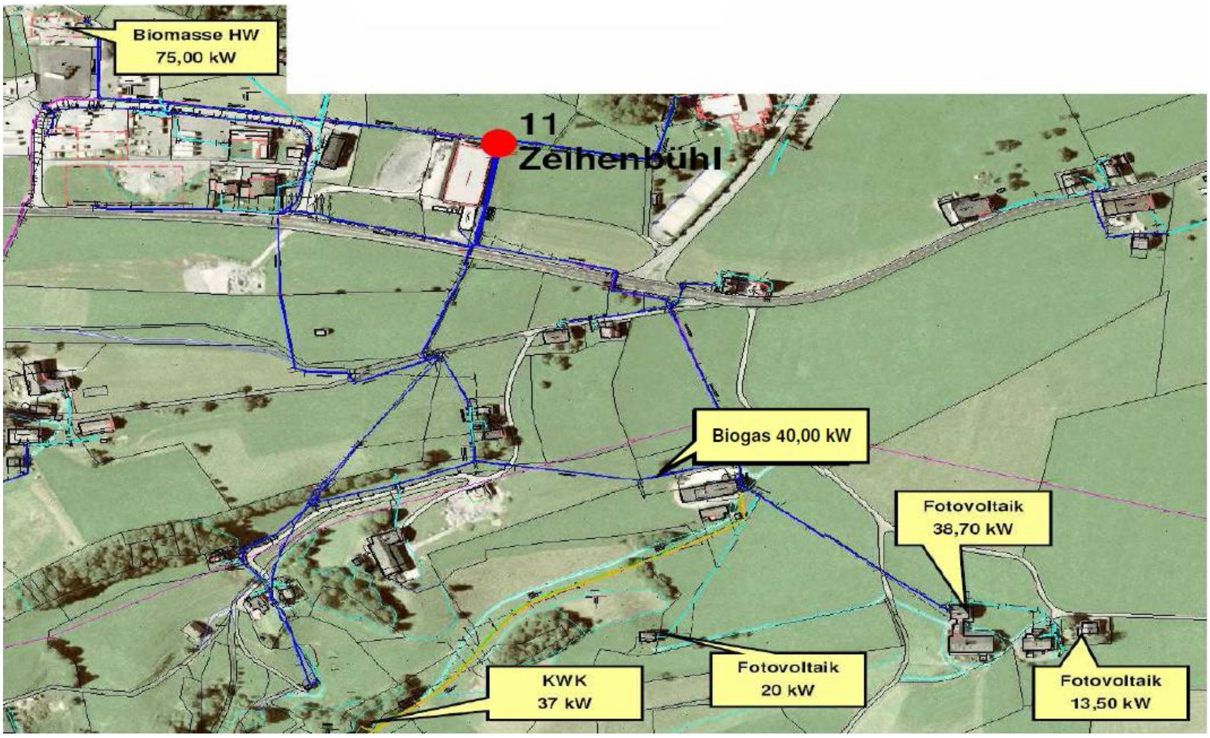

Illustration 5.1.b: Example of a rural grid situation with low load density but high decentralized generation [Nenning 2009]

5.2 Upcoming problems and solutions related to decentralized generation with a perspective until 2020

Scenarios for future PV installations are diverse from very pessimistic to very optimistic. Assuming an optimistic approach from the German Renewable Energy Federation BEE with a PV capacity of 39.5 GW in the year 2020 [BEE 2009] and an assumed number of housing units [Destatis 2007] of about 40 million would result in

$$\frac{39.5\,GWp}{40\cdot 10^{6}\,appartments} = 988\,\frac{Wp}{appartment}.$$

For comparison the peak load in Germany in the year 2009 was 78.5 GW [bdew 2009].

5.2.1 Possible bottlenecks in distribution grids

The maximum loading capacity of the grid on the one hand results from the maximum loading capacity of the grid assets and on the other hand from the provisions and standards on power quality (and here especially on voltage levels).

Simultaneity

Grid assets are planned according to the maximum load that has to be expected. With only one household connected the assets have to be dimensioned according to the maximum load of the household. The more households (or other loads) connected the less the probability is that all have their peak consumption at the same time. This theory results in the simultaneity factor according to which grid assets are dimensioned (illustration 5.2.1.a).

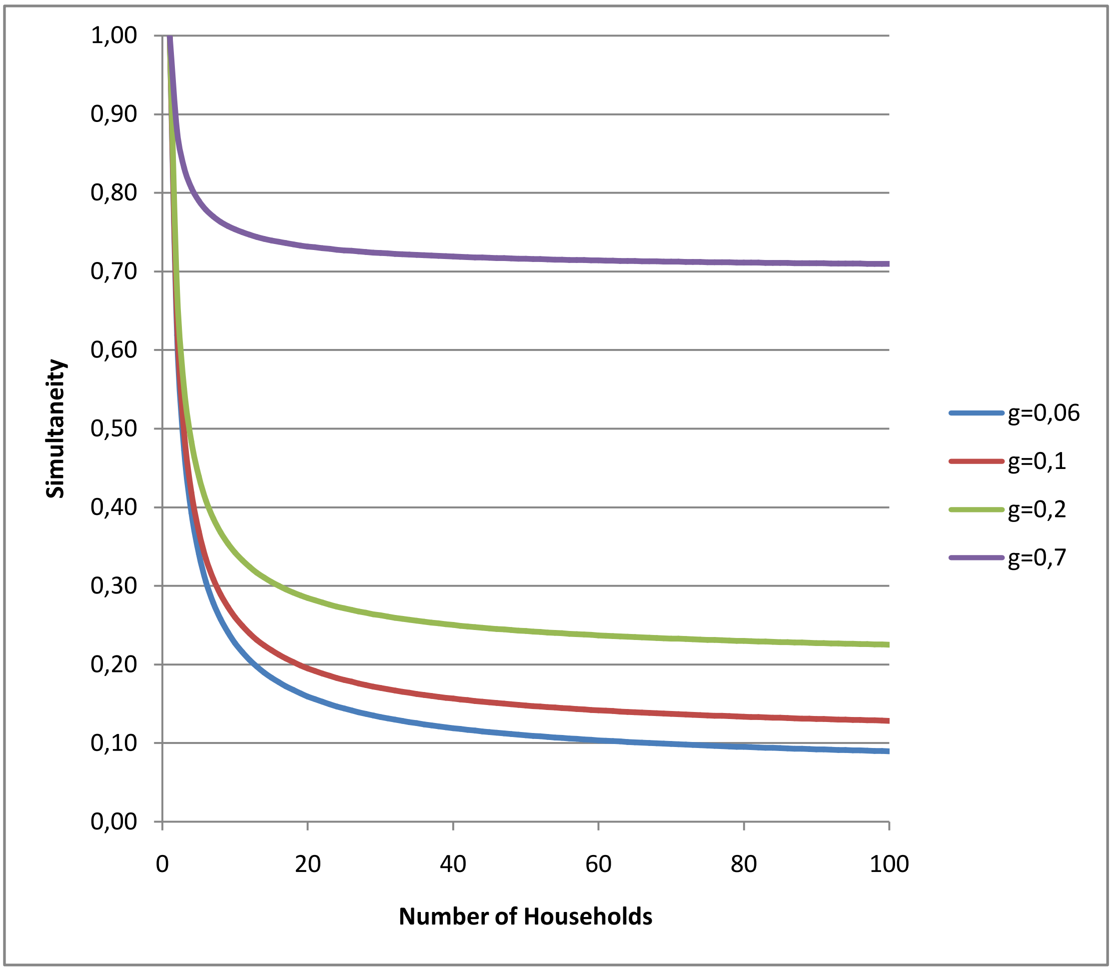

Illustration 5.2.1.a: Simultaneity and peak electrical load depending on number of households considered as function of simultaneity factor "g" for an infinite number of households (g=0,06: high electrification degree including hot water generation; g=0,1: partly electrified with electrical cooking; g=0,2: weak electrification; g=0,7: household with electrical heating), derived from [Kaufmann 1995]

That means that in a neighborhood with typical German households including electrical cooking transformer and lines are not dimensioned to every households peak load but only for about 20 % of it. E.g. when the households peak is around 10 kW the assets are only dimensioned for 2 kW.

With loads independent users this procedure leads to an economic grid design because a sufficient large group of people never behave in the same way (and therefore never consume peak electricity at the same time).

That is completely different with photovoltaic systems. Within a local district weather conditions are almost equal for all systems at any time (with small deviations when clouds are passing through). That results in a simultaneity factor of almost "1" for PV generators.

As a consequence a single house connection is designed for more than 15 kW and by logics also could feed electricity back to the grid in the same amount. But when all houses of a district feed electricity to the grid at the same time the maximum capacity is reduced to 20 %.

Cable and transformer loading

The maximum loading of assets is defined according to their design boundary conditions. A violation of defined loading limits either decreases the life time of the asset or even could destroy it. Relevant parameters are current and voltage.

Increased voltages result in an increased stress to insulation by electrical fields, losses and partly discharges. As insulation of low voltage assets are designed for a limit of 1000 V. Therefore, this criterion does not play a role when discussing decentralized power generation.

Electric currents cause losses in all assets and as a consequence they heat up. When the thermal load is too high aging is accelerated and life times decrease considerably (in case of short circuit currents to only few seconds). Allowed current loadings with boundary conditions like ambient temperatures are given in the asset's norms.

According to [Kerber 2008a] the rated apparent power can be exceeded by 50 % in case of oil distribution transformers. In case of cables the apparent power is the limit [Kerber 2008b].

Voltage Deviations

For a safe operation of the grid and the appliances connected requirements on the voltage levels have been defined. A definition of grid voltages and voltage limits is defined in DIN-IEC 60038 and VDE 0175. A more detailed description contains the European norm DIN-EN 50160. The voltage has to be kept within a limit of $\pm 10\%$ of the rated voltage.

In order to guarantee those norms different bodies have established further guidelines. Relevant to this publication is especially the maximum allowed voltage deviation through decentralized generation capacities. In Germany that are VDEW guidelines for parallel operation of electricity generation units in the low voltage grid [VDEW 2001]. Although the voltage band allowed in low voltage grids is $\pm 10\%$ the guideline limits the contribution of decentralized generation with the criterion $\Delta U \leq 2\%$. Most probably this value will be changed to $\Delta U \leq 3\%$ [Kerber 2009], [FNN 2008]. Then the rules would be equivalent to those of Czech Republic, Austria and Switzerland [VDN 2007a].

Reasons for those limits are not mentioned in the guidelines. Most probable is the explanation according to illustrations 5.2.1.b and 5.2.1.c [Kerber 2009]. Medium and low voltage grids have a fixed coupling. The last possibility (in traditional grid infrastructure) to influence the voltage is at the feeding transformer of the medium voltage grid. Those transformers can change their transmission ratio during operation. Within the medium and also the low voltage grid the voltage at any point results from the load distribution in the grid.

The worst case is shown in the illustrations below and lead to the $\Delta U \leq 3\%$ criterion. Grid string 1 is in a high load condition. The grid is dimensioned in a way that in this case the last connection to a house is kept within the $\pm 10\%$ limit with a safety reserve of 1 %. As a result the voltage at the 20 kV is increased to its maximum of 104 %. The voltage drop is then:

- 5 % voltage drop in the low voltage grid
- 3 % in the distribution system transformer
- 5 % in the medium voltage grid
- 1 % safety reserve.

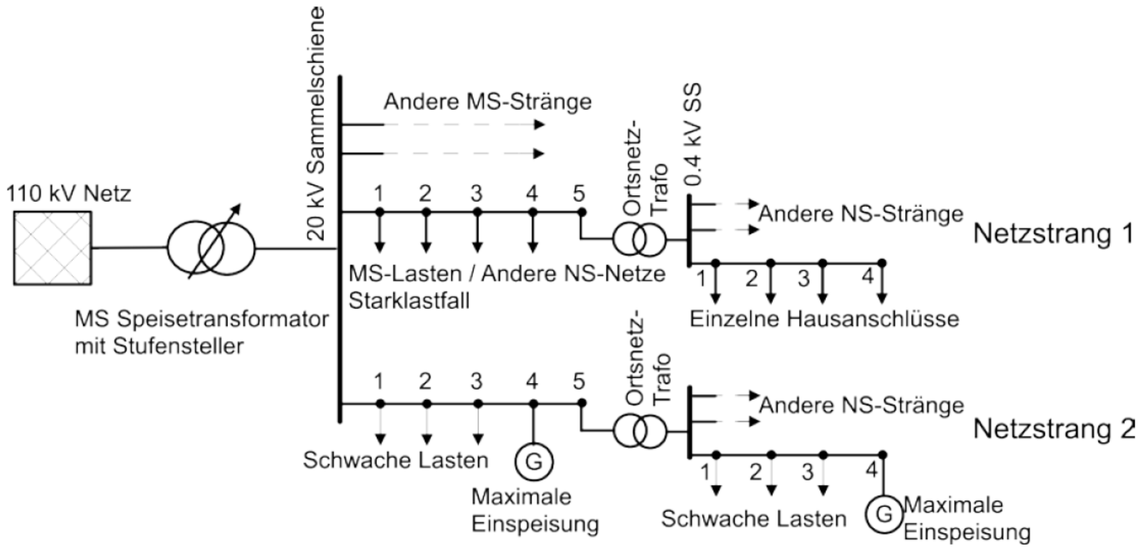

Illustration 5.2.1.b: Exemplary grid to explain voltage deviation limits ("Netzstrang"=grid string; "schwache Lasten"=low load; "Maximale Einspeisung"=maxiumum feed; "Starklastfall"=high load condition; "MS"=medium voltage; "Ortsnetztrafo"=distribution system transformer) [Kerber 2009]

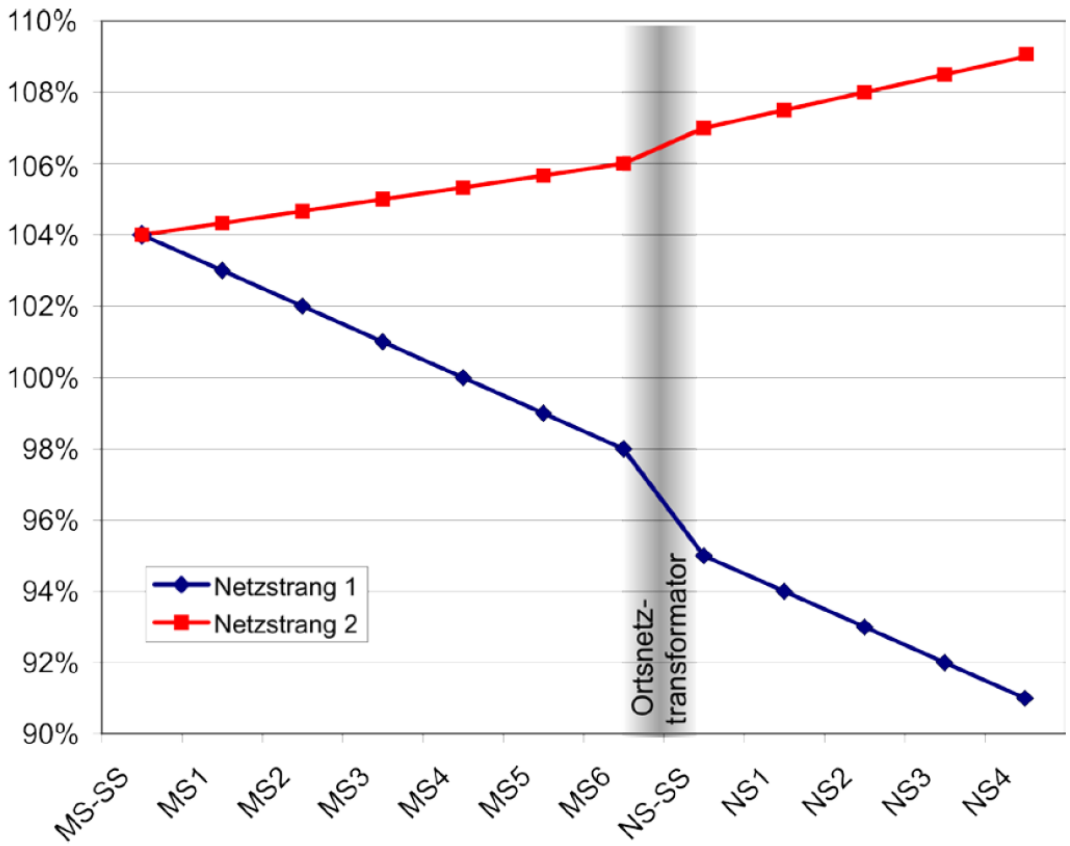

Illustration 5.2.1.c: Voltage distribution in the exemplary grid according to illustration 5.2.1.b [Kerber 2009]

It is further assumed that at the same time in grid string 2 there is no load and the maximum possible feed-in from decentralized power generators. This would lead to an voltage increase instead of an voltage decrease (see illustration 5.2.1.c). At the last house connection of this string the $\pm 10\%$ criterion also has to be kept. It is not possible to lower the voltage at 20 kV level because of grid string 2. Therefore, the remaining voltage drops are distributed accordingly:

- 3 % voltage drop in low voltage grid including transformer
- 2 % voltage drop in medium voltage grid
- 1 % reserve.

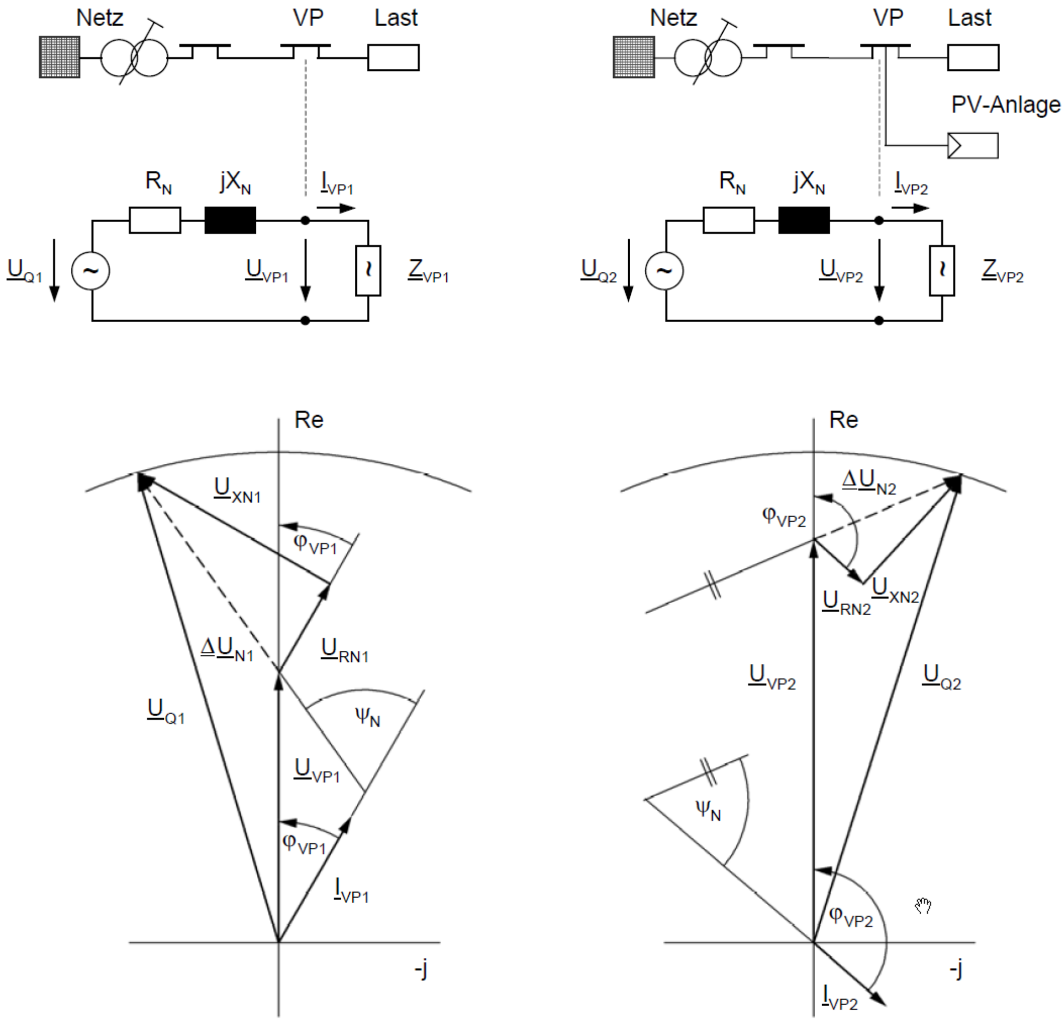

Illustration 5.2.1.d: Schematic to demonstrate voltage decrease in case of ohmic-inductive load (left) and voltage increase in case of injection of active power (right) [Scheffler 2002]

A general conclusion about which of the potential bottlenecks could cause problems to the distribution grid infrastructure is not possible to draw. Whether PV causes problems or not depends on many circumstances, like: transformer and cable selection, length of the distribution grid, load density and available roof surfaces for PV installations.

To evaluate potential grid infrastructure limitations typical grid situations need to be analyzed. In the next section this is done for

- Detached housing areas (high density)

- Single and two family houses areas (low density)
- Villages including courtyard houses areas
- Row of multistory buildings areas
- Block of buildings / city blocks

The most detailed work that has been done in this area is the dissertation from Jörg Scheffler from TU Chemnitz [Scheffler 2002]. If not mentioned differently all analysis results are from that work. In addition to that the results from other studies are included and cited.

5.2.2 Analysis of different distribution grid structures

<u>Detached Housing Area (high density)</u>

This type is maybe the most typical and common way of living in Germany. It is a suburb structure mostly located at the border areas of cities. Electricity supply is done by cables. Illustration 5.2.2.a gives an impression of this area type and illustration 5.2.2.b shows the studies exemplary grid.

The boundary conditions are the following:

- Medium voltage grid:
    - 20 kV
    - Short circuit power 116 MVA
    - Grid impedance angle 39°
- Transformer apparent power: 630 kVA
- Cables: NAYY 4x150 mm²; I_{max}=265 A
- House connections: NAYY 4x25 mm²; I_{max}=90 A
- 1,15 accommodation units per house connection (85 % detached houses; 15 % two family houses)
- Number of accommodation units: 176
- Peak load quotient per accommodation unit: 2.0 kW
- Other loads: 2 kW telecommunication and one restaurant (15 kW_{max})
- Roof inclination: 40°

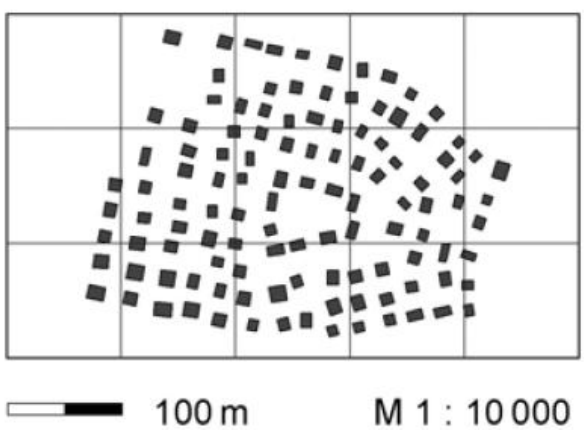

Illustration 5.2.2.a: Exemplary detached housing area with high density [Scheffler 2002]

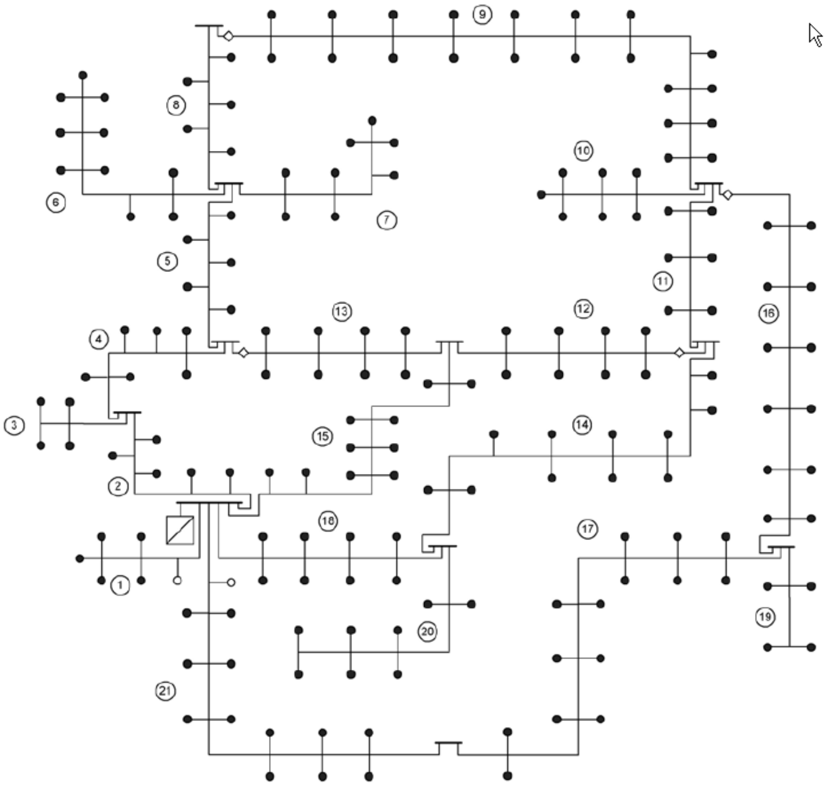

Illustration 5.2.2.b: Grid map of the studied exemplary detached housing area [Scheffler 2002]

The main results of this grid type analysis have been (illustration 5.2.2.c):

- With an installed PV capacity of 5.32 kW_p per accommodation unit the transformer is at its loading limit.
- Cables are already at their limit with an installed capacity of 2.83 kW_p.
- Limitations due to voltage deviations are given according to the fluctuation range within the medium voltage grid (horizontal axis). With realistic fluctuations voltage does not mean a further limitation installed capacity. In case the medium voltage band would be $\pm 6.6\%$ the PV capacity would be limited to only 0.7 kW_p per accommodation unit. Bigger variations of the medium voltage band are not allowed due to the voltage limit in the low voltage grid during peak load condition.
- In case the medium voltage is controlled in a way that according to the load the minimum voltage is kept the possible installation area is increased to the dark grey area in illustration 5.2.2.c
- With a medium voltage band of $\pm 3\%$ the maximum capacity that is limited by cable loading can be installed. This is only about 30 % of the suited roof area but nevertheless the installed capacity would be almost 500 kW_p in this small neighborhood.

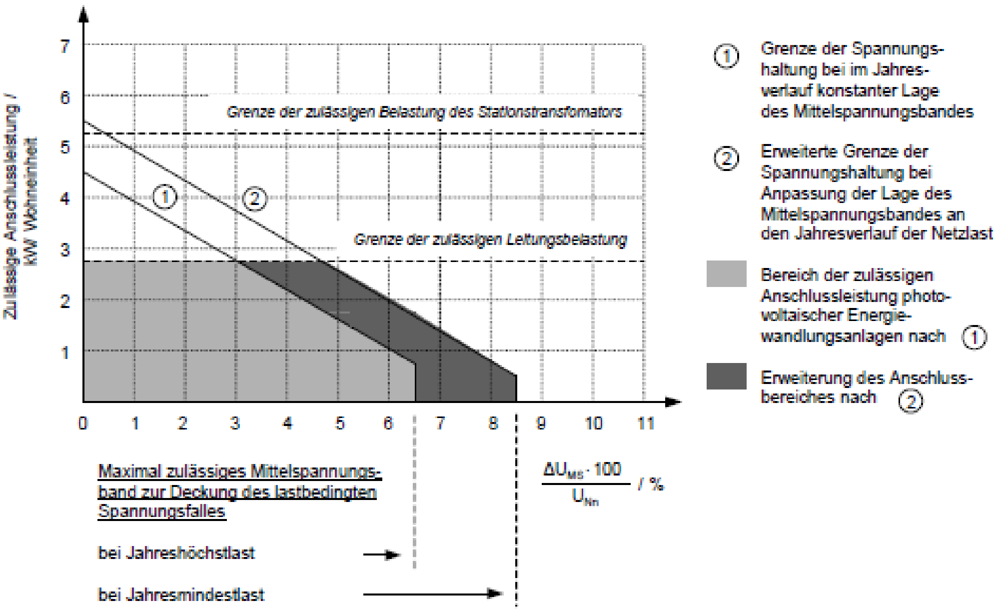

Illustration 5.2.2.c: Limitations for PV installation capacity potential within the exemplary grid for a detached housing area (vertical axis = PV capacity in kW$_p$; horizontal axis = maximum medium voltage band allowed with yearly peak load (light grey) and yearly minimum load (dark grey) [Scheffler 2002]

[Braun 2009] also discusses a suburb area according to illustration 5.2.2.d. Five branch feeders are connected to a 630 kVA 10/0.4 kV distribution transformer and distribute electrical energy to the consumers. One feeder is modeled in more detail to show the influence of PV power feed-in at different injection points along the branch feeder. The overall length of every single branch feeder is about 300 m. The maximum apparent power of each of the five branch feeders is limited to 182 kVA due to 250 A circuit-breakers at the respective terminals at the low voltage bus bar and an assumed minimum power factor of 0.95. 18 residential homes, each of them equipped with a PV generator of 5 kWp, are connected along the respective branch feeders. The length of the spur feeder cables, which connect the respective injection points with the branch feeder cable are set to 10 m.

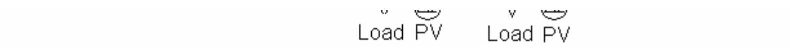

Illustration 5.2.2.d: Exemplary grid of a suburban living area [Braun 2009]

Braun calculates with the assumption of a fixed medium voltage at 1.0 p.u. With this assumption he concludes that the $\Delta U \leq 2\%$ criterion but not the $\Delta U \leq 3\%$ criterion would be violated. The results are far away from exceeding the 1.1 p.u. Also transformer and cable loading is not at the limit.

[Degner 2010] investigated a synthetic low voltage grid. The main focus also here has been laid on voltage management. The grid consists of six identical strings (illustration 5.2.2.e). Each string has a length of 600 m with every 25 m a house interconnection (24 connection points per string). The main cable is 150 mm² VPE-Copper with a thermal capacity of 270 kVA and an impedance load per unit length of (0,124+j0,069) Ω/km. the connection line to the buildings have a length of 30 m each and are of 50 mm² VPE-Copper type with a thermal capacity of 140 kVA and a impedance laod per unit length of (0,387+j0,072) Ω/km. the distribution transformer 20/0,4 kV has a capacity of 630 kVA of type Dyn5 and a short circuit voltage of 6 %.

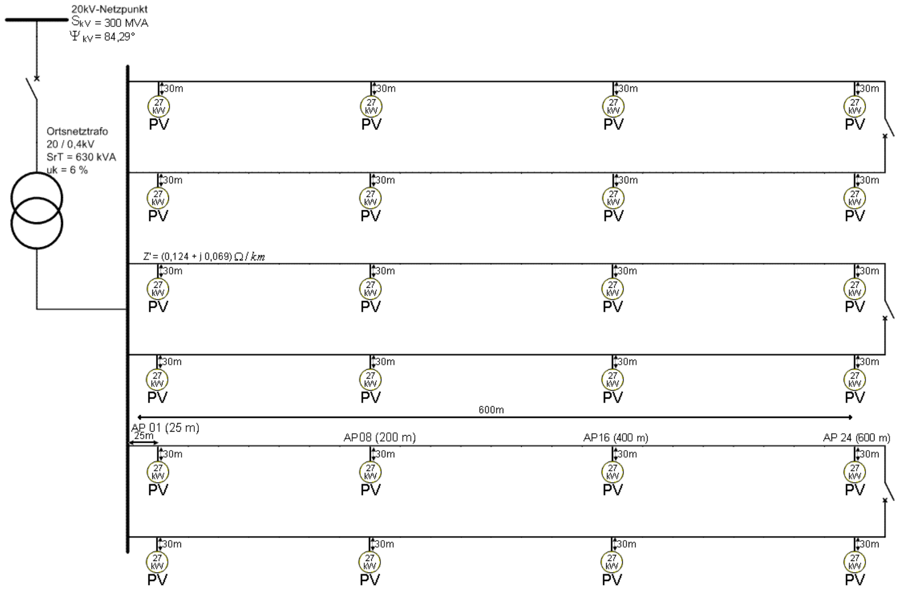

Illustration 5.2.2.e: Exemplary low voltage grid from [Degner 2010]

Loads have not been considered. At every string four PV systems with a capacity of 27 kW each had been connected to injection points 1, 8 16 and 24. Illustration 5.2.2.f shows the voltage distribution for different voltage management strategies. The $\Delta U \leq 2\%$ criterion cannot be kept with a $\cos(\varphi)=1$. With a fixed $\cos(\varphi)=0.9$ the transformer voltage decreases to less than 0.98 p.u. With a fixed $\cos(\varphi)=0.95$ voltage is always kept in the tolerance band. It further was found that with a $Q(U)$-function inverters close to the transformer and at the end of the line can have an opponent behavior resulting even in an increasing line load exchanging reactive power among each other.

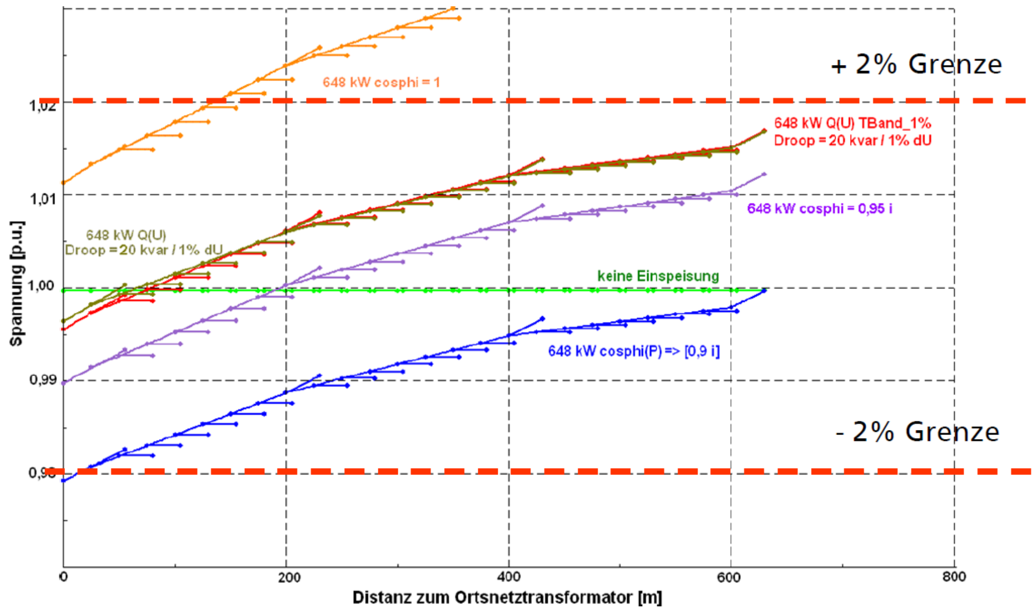

Illustration 5.2.2.f: Voltage distribution along the cable with different voltage management strategies (horizontal axis: distance from transformer [m]; vertical axis: voltage [p.u.]) [Degner 2010]

Depending on the way of reactive power provision the in table 5.2.2.a presented maximum injection power was determined by Degner. Consideration was limited to the voltage criteria. Degner mentions that in some scenarios transformer and cables are overloaded. The results of scenarios three to five are displayed in illustration 5.2.2.g.

Table 5.2.2.a: Maximum active power injection with different reactive power management strategies (scenario1: $\cos(\varphi)=1$; scenario2: $\cos\varphi(P)$ function of $\cos(\varphi)=0.9$; scenario3: $\cos(\varphi)=0.95$; scenario4: $Q(U)$-characteristic; scenario5: $Q(U)$-characteristic, but PV generators differently assembled)

Szena-rio	Regelungsverfahren / Einstellung	Bemessungsleistung / Ver-teilung der PV- Anlagen	Max. Wirkleistungs-einspeisung [MW]
1	Fixer cos φ cos φ = 1	2 x 27 kW; AP 1 und AP 24 oder AP 8 und AP 16	2 x 6 x 0,027 = 0,324
2	cos φ (P)-Statik oder Fixer cos φ cos φ = 0,9 untererregt	4 x 27 kW; AP 1, AP 8, AP 16 und AP 24	4 x 6 x 0,027 = 0,648
3	Fixer cos φ cos φ = 0,95 untererr.	7 x 27 kW; AP1, AP 4, AP 8, AP 12, AP 16, AP 20 und AP 24	7 x 6 x 0,027 = 1,134
4	Q(U)-Kennlinie	7 x 27 kW; AP1, AP 4, AP 8, AP 12, AP 16, AP 20 und AP 24	7 x 6 x 0,027 = 1,134
5	Q(U)-Kennlinie (PV Anlagen gezielt an-geordnet)	12 x 27 kW; AP1 – AP 10, AP 16 und AP 24	12 x 6 x 0,027 = 1,944

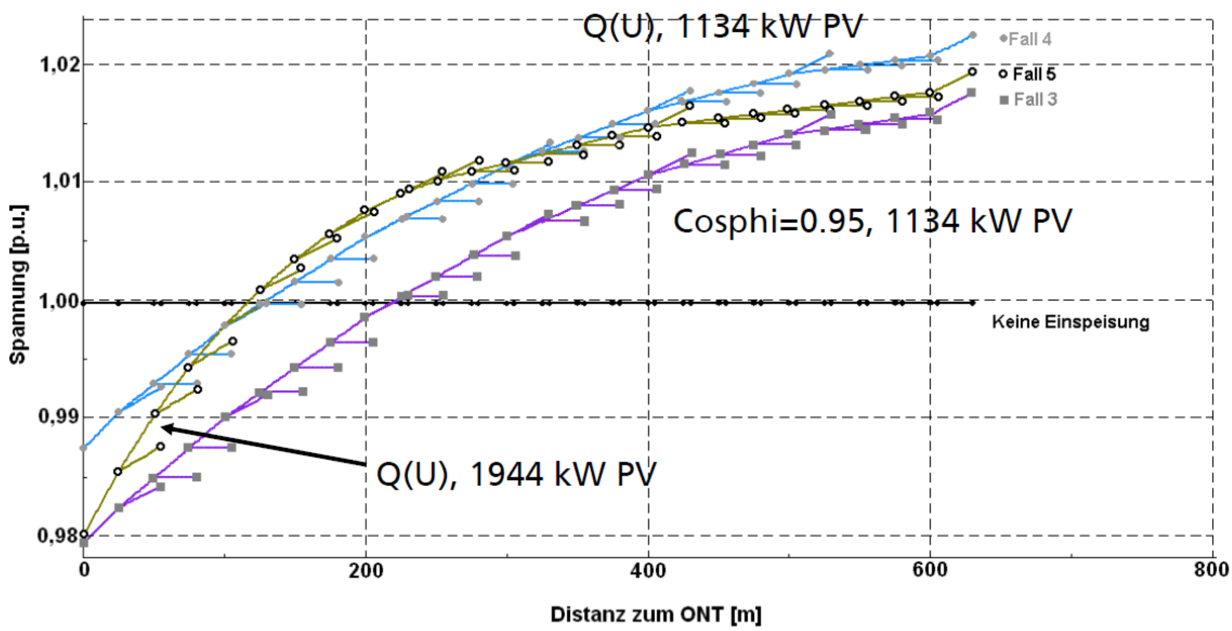

Illustration 5.2.2.g: voltage distribution of the scenarios three to five of table 5.2.2.a [Degner 2010]

In [Kerber 2007] many grids have been investigated. The results in this document are split with the attempt to distribute them according to the methodology Scheffler has used. Kerber determined the typical maximum PV capacity per building for each area type (illustration 5.2.2.h). In case the capacity was bigger than 30 kW_p the value was limited to that size.

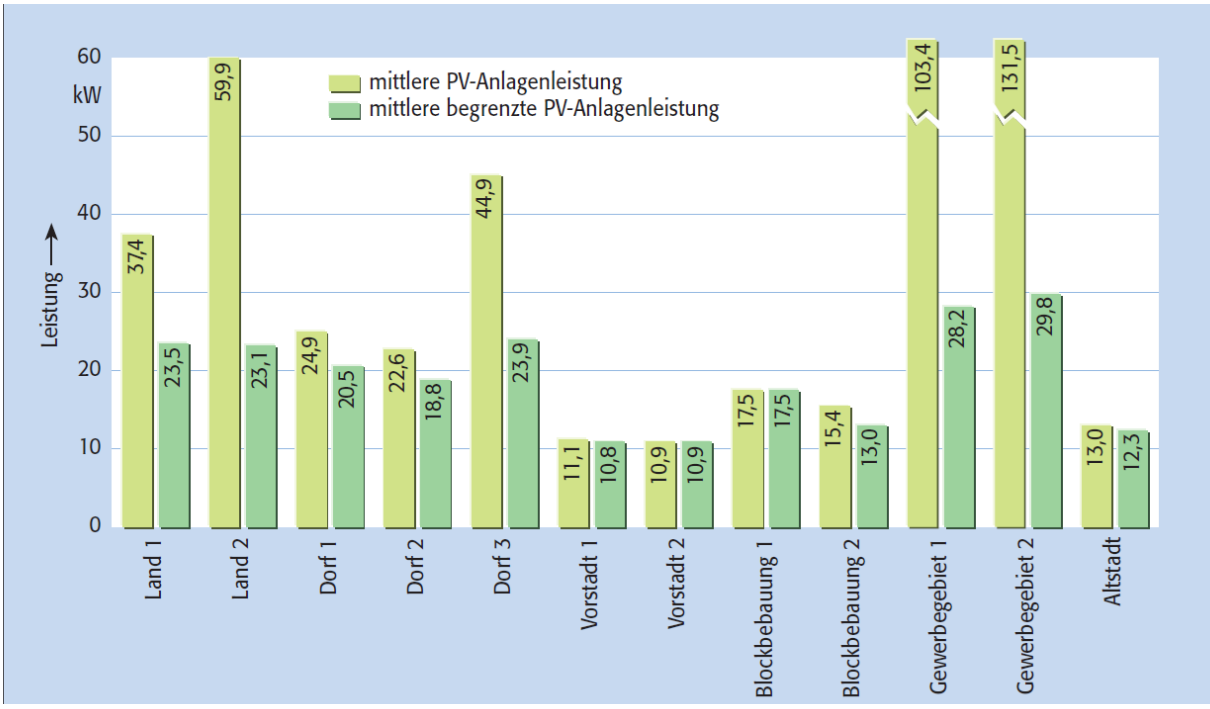

Illustration 5.2.2.h: maximum PV capacity per building in different area types [Kerber 2007]

The results for suburban areas are displayed in illustration 5.2.2.i. The mean theoretical capacity had been determined to about 10 kW_p. All investigated grids cannot take this capacity. This does not fail because of single criterion but by all of the investigated ones.

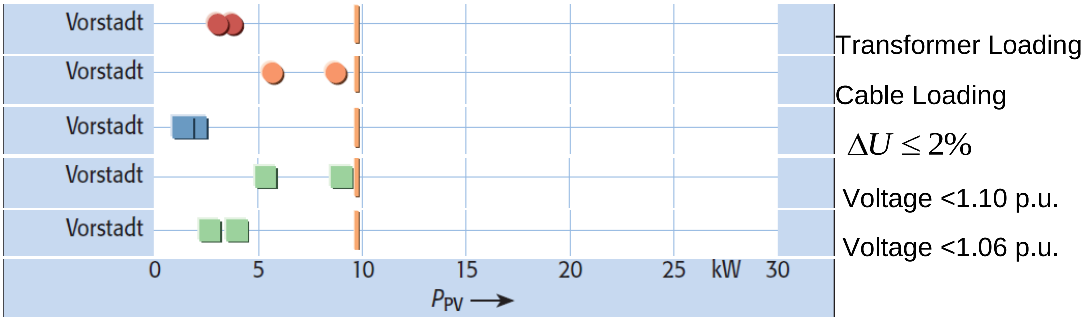

Illustration 5.2.2.i: Limiting criteria for PV installation in suburban area grids [Kerber 2007]

Single and Two Family Houses Area (low density)

This type is of a similar structure like the one described before. It is a suburb structure mostly located at the border areas of cities. The lots of land are bigger than in the one described before what results in a lower density. Electricity supply is mostly done by cables, sometimes by overhead lines. Illustration 5.2.2.j gives an impression of this area type and illustration 5.2.2.k shows the studies exemplary grid. The exemplary grid is a single fed mesh network and operated as radial distribution system. It is arranged as insulated overhead line.

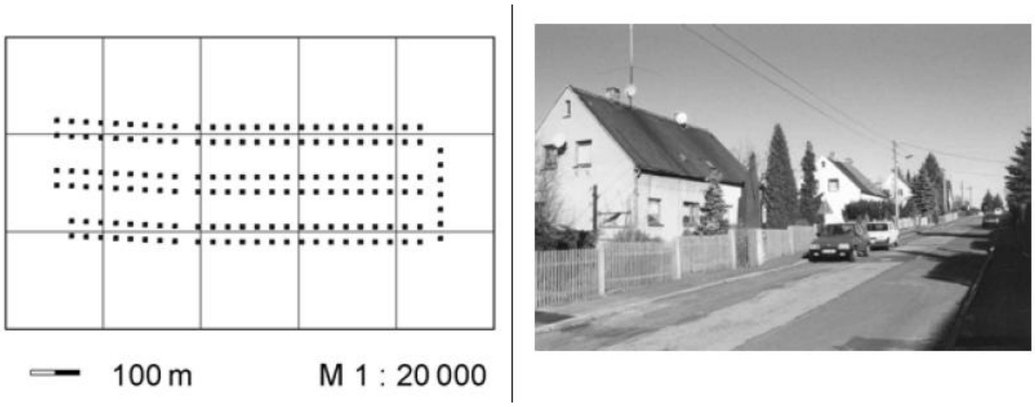

Illustration 5.2.2.j: Exemplary single and two family houses area with low density

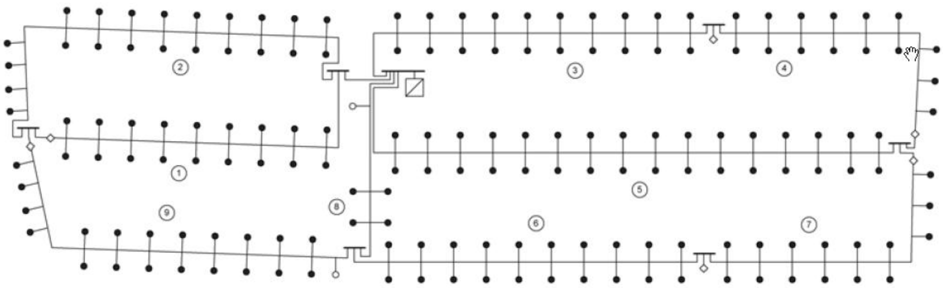

Illustration 5.2.2.k: Grid map of the studied exemplary single and two-family houses area [Scheffler 2002]

Similar like in the grid investigated before the limitation in the single and two-family houses area is limited by the cable capacity. The capacity limit here is lower because of the lower population density and therefore bigger cable lengths and was determined to be 2.4 kW_p per accommodation unit. This is the relevant limit when the medium voltage band is less or equal to $\pm 2{,}3\%$ of the nominal voltage. With reduced PV capacities the medium voltage band can be increased up to $\pm 6.2\%$ before the voltage drop according to peak load is the limitation. With the 2.4 kWp per accommodation about 50 % of the theoretical potential can be accessed.

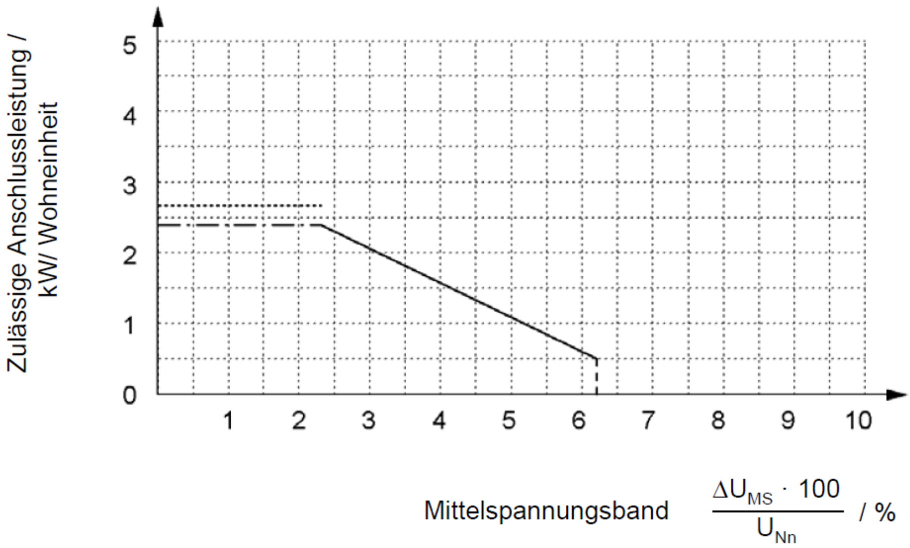

Illustration 5.2.2.l: Limitations for PV installation capacity potential within the exemplary grid for a single and two-family houses area (vertical axis = PV capacity in kW_p; horizontal axis = maximum medium voltage band allowed) [Scheffler 2002]

Villages Including Courtyard Houses Area

This grid example is typical for rural areas. Electricity supply is mostly done by cables, sometimes by overhead lines. The grid type is a radial distribution system. In the exemplary grid about 15 % of the houses include agricultural holdings. Into the investigations a line tap of 800 meters behind grid string number two is assumed.

Illustration 5.2.2.m: Exemplary village with included courtyard houses area [Scheffler 2002]

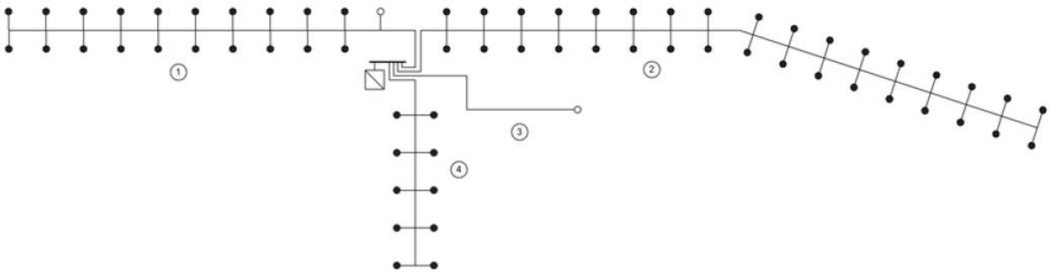

Illustration 5.2.2.n: Grid map of the studied exemplary village with included courtyard houses area [Scheffler 2002]

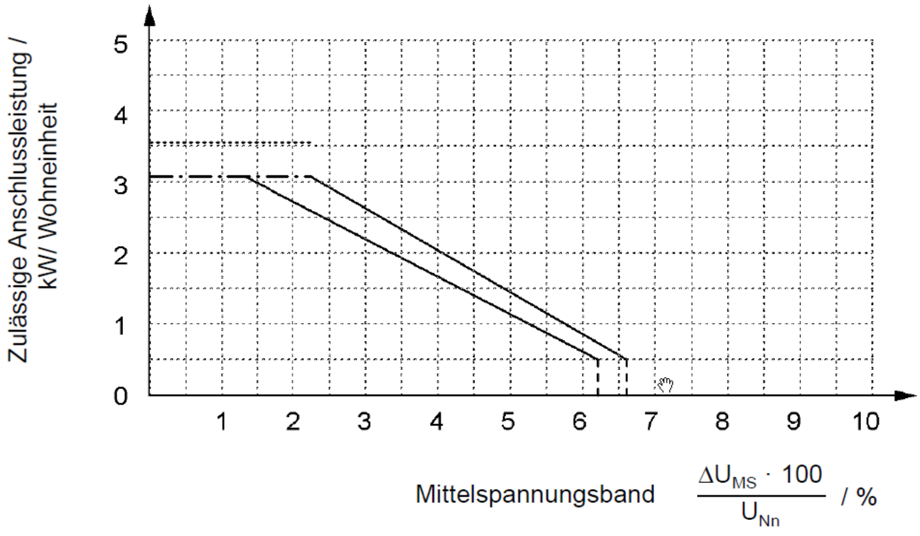

Illustration 5.2.2.o: Limitations for PV installation capacity potential within the exemplary grid for a village with courtyard houses area. The left line indicates the border with the line tap, the right one without (vertical axis = PV capacity in kW_p; horizontal axis = maximum medium voltage band allowed) [Scheffler 2002]

The maximum PV capacity again is limited by the cable capacity and should not exceed 3.1 kW_p per accommodation unit. Due to the wide-stretched grid topology and the resulting voltage drops the installed capacity decreases already with a medium voltage band bigger than $\pm 2{,}5\%$ (illustration 5.2.2.o). The theoretical PV capacity potential can only be used by 20 %.

In [Braun 2009] also a rural low voltage grid is investigated (illustration 5.2.2.p). The assumed overall length of each single branch feeder is 270 m, with 6 residential homes connected. The average distance between the single injection points is 54 m. All conductors are overhead lines with one neutral phase. Three feeders branch off the low voltage bus bar, supplied by a 100 kVA 20/0.4 kV distribution transformer.

At the very end of each feeder, a farm is connected to PCC6 consisting of a residential home, the farm itself and a 30 kVA PV generator.

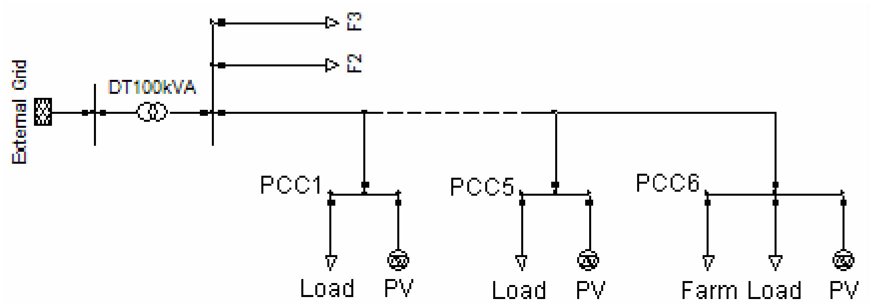

Illustration 5.2.2.p: Exemplary rural grid with a high installed PV capacity at the final end of each grid string [Braun 2009].

Again, Braun takes the assumption that the medium voltage is constant. With this assumption both the $\Delta U \leq 2\%$ criterion and the $\Delta U \leq 3\%$ criterion is violated independent of the measure taken. Nevertheless, with the assumption taken the voltage is kept within the $\pm 10\%$ limit. But even without PV the maximum load violates the 0.9 p.u. criterion. Therefore, it is very probable that the distribution transformer has a setting different of the assumed one. Braun also comes to the conclusion that the transformer would be overloaded not taking into account the cable load.

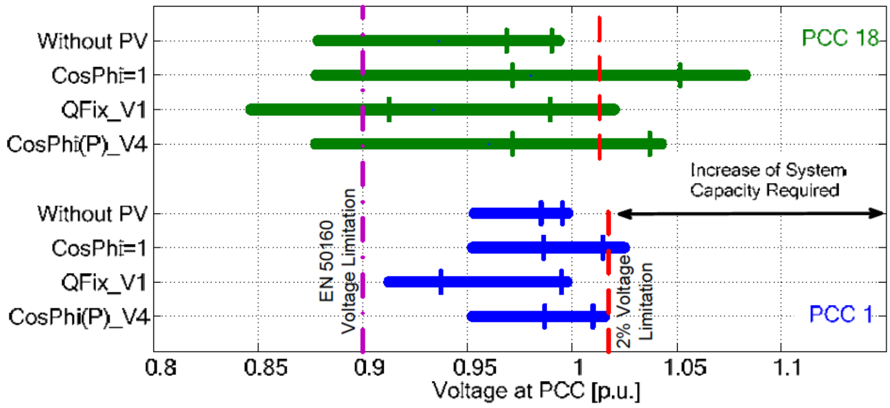

Illustration 5.2.2.q: Voltage range at transformer and end of line with different measures to influence the voltage distribution [Braun 2009]

For village structures the results of [Kerber 2007] are similar to them of suburbs. The enormous theoretical capacity for PV installations cannot be realized because all criteria are violated before (illustration 5.2.2.r).

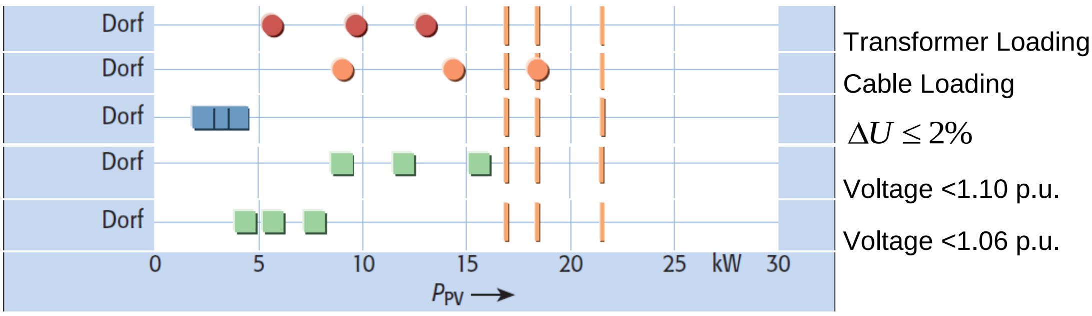

Illustration 5.2.2.r: Limiting criteria for PV installation in village grids [Kerber 2007]

Row of Multistory Buildings

This area type is typically located at the border of large and small cities and sometimes in newer city centers. They are supplied by cables. Because of the building sizes each building typically is supplied via a single grid string. At grid string seven a school is connected to (illustrations 5.2.2.s and 5.2.2.t).

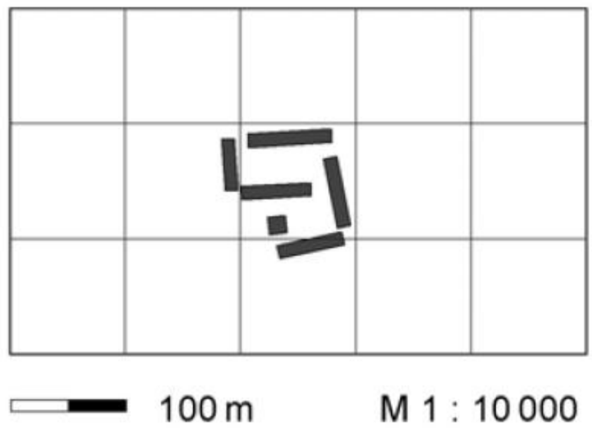

Illustration 5.2.2.s: Exemplary area with rows of multistory buildings [Scheffler 2002]

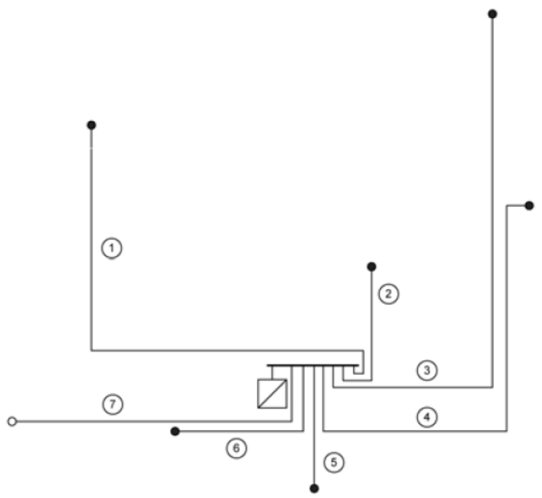

Illustration 5.2.2.t: Grid map of the studied exemplary area with rows of multistory buildings [Scheffler 2002].

Different to the grid types described before in this exemplary grid the maximum PV capacity is limited by the transformer loading when the capacity has reached 2.2 kW_p per accommodation unit. The small dimension of the grid area is the reason why voltage drops are not significant. Limitations here start when the medium voltage band exceeds $\pm 6{,}7\%$. Load justified limitations even start not until a band of $\pm 8{,}5\%$. An increase of the transformer rated power from 400 kVA to 630 kVA increases the capacity limit to 3.4 kW_p per accommodation unit (upper pointed line in illustration 5.2.2.u). The potential of increasing the voltage more than $\Delta U \leq 2\%$ at the point of connection is given in this case. Nevertheless the allowed low voltage band of $\pm 10\%$ is never violated. Therefore this criterion is questionable.

As the limit is always given in kWp per accommodation unit and those buildings contain many units the roof potential can be exploited by 100 % (even facades could be equipped with PV).

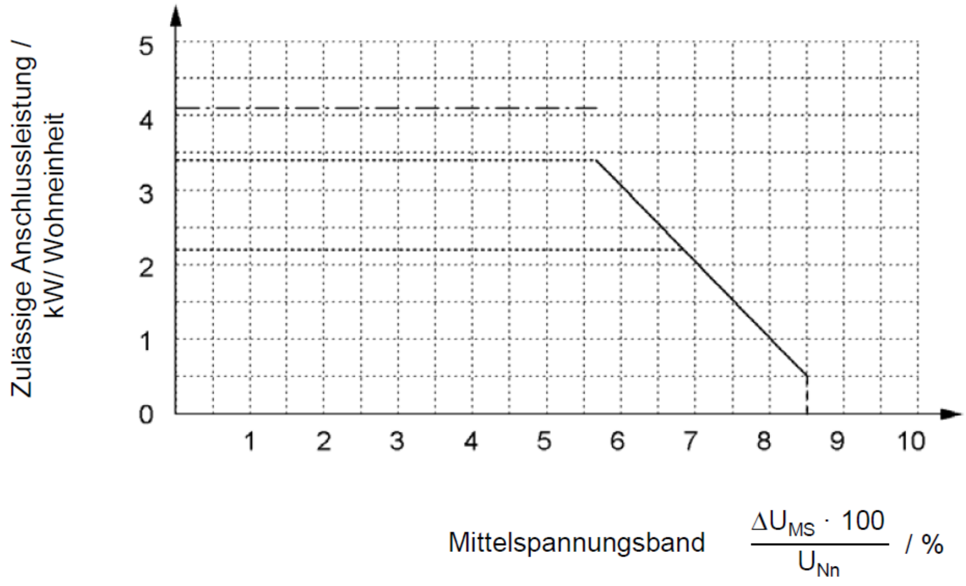

Illustration 5.2.2.u: Limitations for PV installation capacity potential within the exemplary grid for an area with rows of multistory buildings. (vertical axis = PV capacity in kW_p; horizontal axis = maximum medium voltage band allowed) [Scheffler 2002]

Completely different from the other grids investigated before are the city grids. Due to the strong and from their geographical extension small grid all available roof capacities can be applied. Only the $\Delta U \leq 2\%$ criterion is violated (illustration 5.2.2.v). As it will be discussed later this criterion might not be critical in reality.

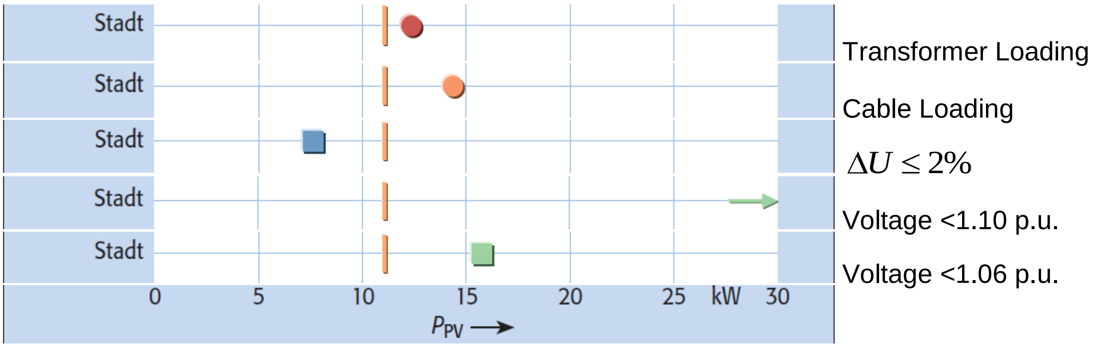

Illustration 5.2.2.v: Limiting criteria for PV installation in city grids [Kerber 2007]

Block of Buildings / City Block

This area is typical for city centers. These areas are supplied via cables, have high load densities and line lengths are limited. The exemplary grid (illustrations 5.2.2.w and 5.2.2.x) supplies 36 buildings. The mesh grid is fed by several transformers. Via opened section points it is operated as a radial distribution system.

Here, the installation capacity is limited by the loading of cables to 2.4 kW per accommodation unit. Due to the limited line lengths the voltage drops are small and a limitation by voltage is only valid for a medium voltage band exceeding $\pm 7\%$ (illustration 5.2.2.y).

Available roof area is small compared to the number of accommodation units. therefore, the theoretical potential can be completely used.

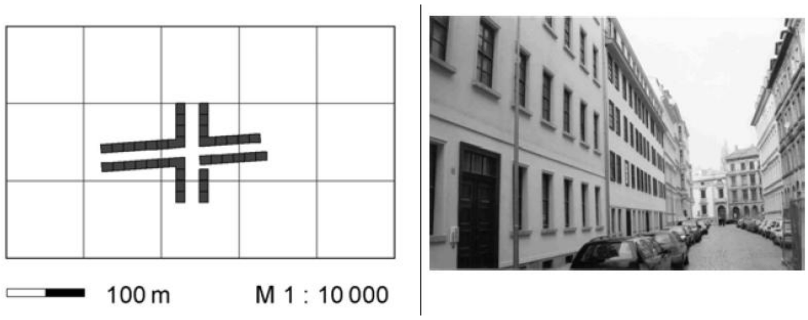

Illustration 5.2.2.w: Exemplary area of a city block [Scheffler 2002]

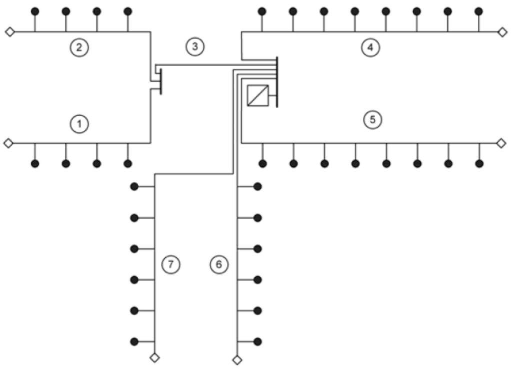

Illustration 5.2.2.x: Grid map of the studied exemplary city block area [Scheffler 2002].

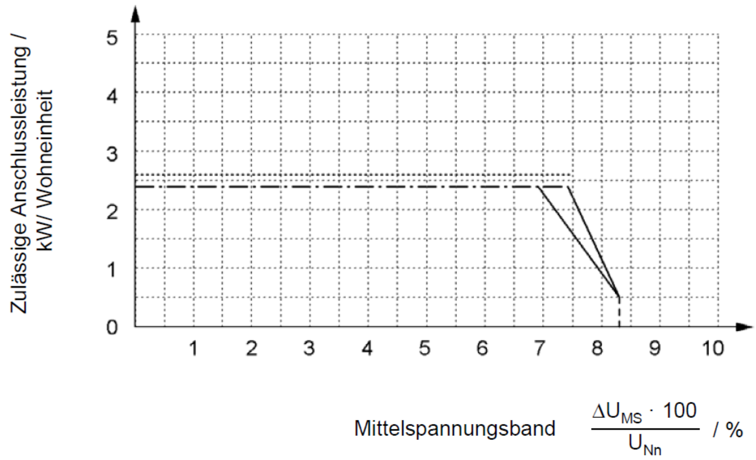

Illustration 5.2.2.y: Limitations for PV installation capacity potential within the exemplary grid for a city block. (vertical axis = PV capacity in kW_p; horizontal axis = maximum medium voltage band allowed) [Scheffler 2002]

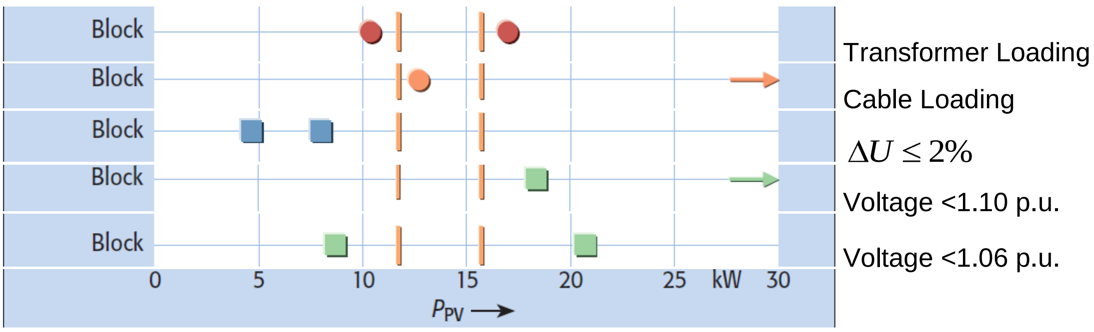

Illustration 5.2.2.z: Limiting criteria for PV installation in block area grids [Kerber 2007]

<u>Other grids investigated by [Kerber 2007]</u>

In industrial areas investigated all the theoretical capacity can be installed, see illustration 5.2.2.aa.

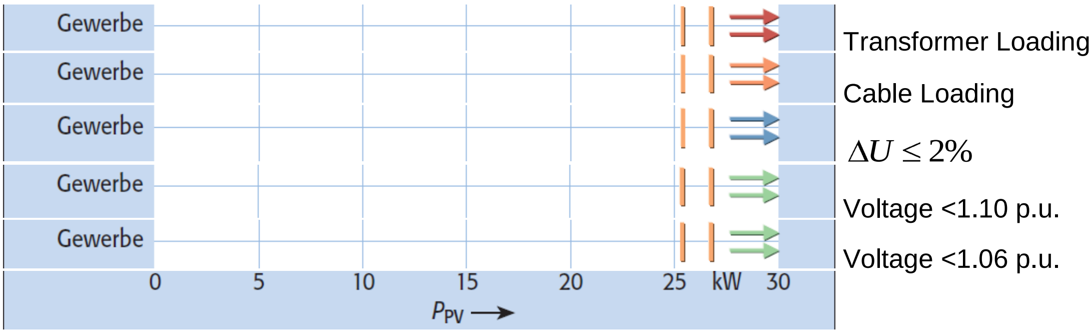

Illustration 5.2.2.aa: Limiting criteria for PV installation in industry grids [Kerber 2007]

In rural area available roof surfaces are very large and the potential cannot be explored. Nevertheless, neglecting the $\Delta U \leq 2\%$ criterion and taking into account not overloading the assets and keeping within the 1.1 p.u. range the capacity per house could be around 12 kW_p (illustration 5.2.2.ab).

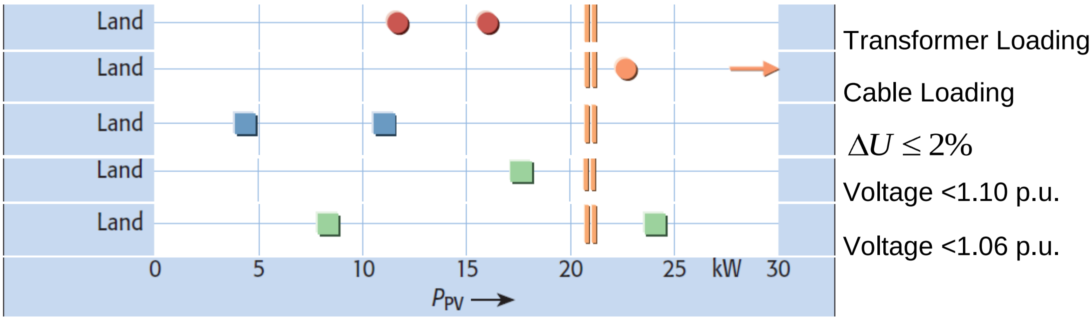

Illustration 5.2.2.ab: Limiting criteria for PV installation in rural grids [Kerber 2007]

<u>Summary and discussion from investigations of grids in different settlement areas</u>

The following can be concluded from the sections before:

- The maximum PV installation capacity is limited by asset loadings. In most cases the limit is determined by cable capacities. In case of short line lengths and high load density (multistory buildings, city blocks) the limit is due to the transformer. The maximum possible installation capacity ranges from 2.2 kW_p to 3.1 kW_p per accommodation unit.
- In areas with multistory buildings and city centers with building blocks the complete capacity can be exploited. In suburbs with predominantly detached houses or rural areas with large roof surfaces the potential is limited by the distribution grid infrastructure.
- Only large medium voltage bands influence the maximum installation capacity. This might be only the case in low voltage distribution grids that are located far from high voltage to medium voltage transformation substations.

5.2.3 Solutions to overcome bottlenecks in distribution grid infrastructure

<u>Solutions in case "voltage violation" is the problem</u>

The evaluation of typical grids has shown that the "voltage violation" problem is seldom the case – and when then it is more of a theoretical nature:

- The $\Delta U \leq 2\%$ criterion or the $\Delta U \leq 3\%$ criterion, respectively, was derived from a situation when one grid string was loaded with its peak and therefore the medium voltage needed to be set to a maximum allowed. At the same time in another grid string it is assumed that there is no or minimum load but maximum feed-in from PV systems. This is not a very probable assumption.
- [Scheffler 2002] reports that load caused voltage drops normally are of a maximum of 2 % and this only in case of grid sections that are far away from transformation station and only in case that storage heating systems cause a high load. And that is normally during night where the power injection from PV is zero.
- Before European and international harmonization of norms low voltage grids have been designed for a voltage deviation of $\pm 5\%$. Therefore, the today's $\pm 10\%$ should leave a large safety margin.

Nevertheless, there is a theoretical danger and several grid management solutions in future could be undertaken to avoid voltage violation even with higher installed capacities.

<u>Solution "Voltage Violation" 1</u>: voltage and/or current are measured at every low voltage transformer. From this information one can draw conclusions on the line loading and take adjustments on the high voltage to medium voltage transformer stations in order to keep all areas within a grid part in its range. Those transformers can change their transformation ratio on load whereas low voltage transformers only can be adapted under no load condition in fixed steps of e.g. $\pm 2.5\%$ (see illustration 5.2.3.a) or $\pm 4\%$.

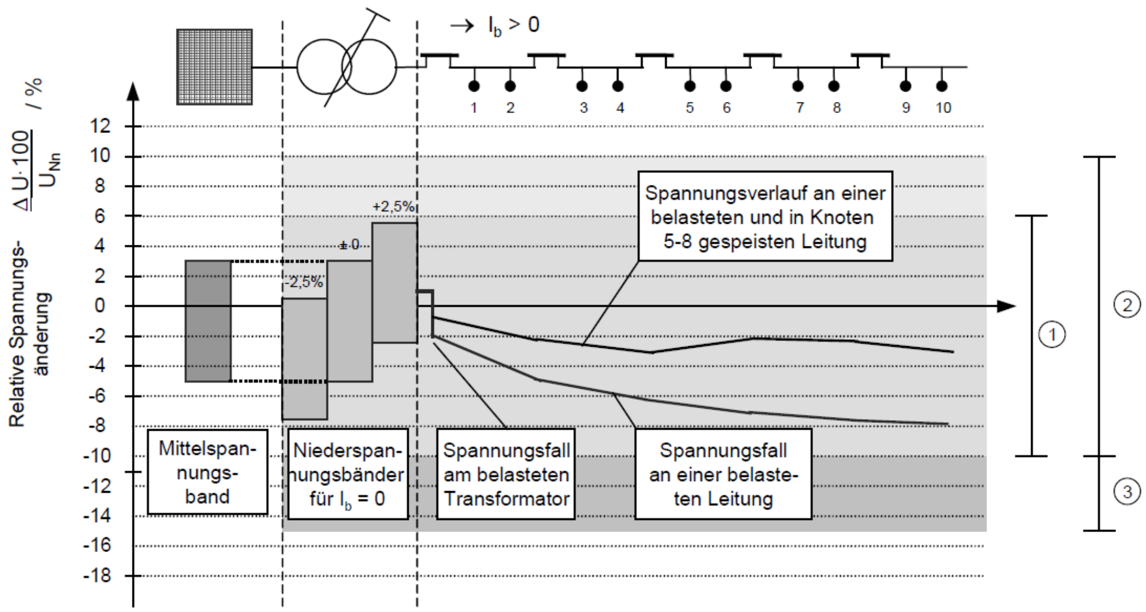

Illustration 5.2.3.a: Settings of low voltage transformers [Scheffler 2002]

Solution “Voltage Violation” 2: with future regulations for system services that have to be provided by decentralized power generators (like nowadays already the case in medium voltage grids) information about voltage can be gathered even from the distributed inverters of PV plants. On basis of that information again action can be taken in the medium voltage transformer station.

Solution “Voltage Violation” 3: completely without communication the problem could be solved decentralized by the PV inverters themselves. For safety reasons PV inverters contain security devices that measure among other parameters grid voltage. When the $\pm 10\%$ criterion is violated they can automatically reduce power injection. Additional expenditure compared to today’s inverter design would be minimal.

A problem could be more the social compatibility because always those inverters need to reduce power injection first that are located at the end of a grid string.

Another problem is the legal boundary condition of the renewable energy act that guarantees that renewable electricity plant operators have the right to feed-in their generated electricity.

Solution “Voltage Violation” 4: Not only in the low voltage grid but also in the medium voltage grid an increasing number of renewable energy generators are installed - mainly wind power generators. Those generators have excellent abilities in order to influence the voltage level in the medium voltage grid. According to “Systemdienstleistungsverordnung” [AnxServiceAct 2009] those generators are obliged to perform voltage regulation [Stadler 2009]. In advanced grid management structures this ability can be applied in order to also improve the voltage in low voltage grid.

Solution “Voltage Violation” 5: PV inverters can inject reactive currents in order to influence voltage and keep within the $\pm 10\%$ limit.

Illustration 5.2.3.b shows the voltage at a PV installation point $\underline{U}_{VP}$ in relation to the transformer voltage $\underline{U}_{Q}$ and the voltage drop on the cable impedance. In case 1 reactive power is fed to the grid and consumers (or generating unit) draw reactive power from the grid. Due to the R/X-relation in the grid the voltage at the connection point is lower at the transformer station. In case 2 only active power is fed to the grid. Grid loading is minimized and the voltage is slightly higher than at the transformer station. With active and reactive power generation the voltage increase at the injection point is getting larger.

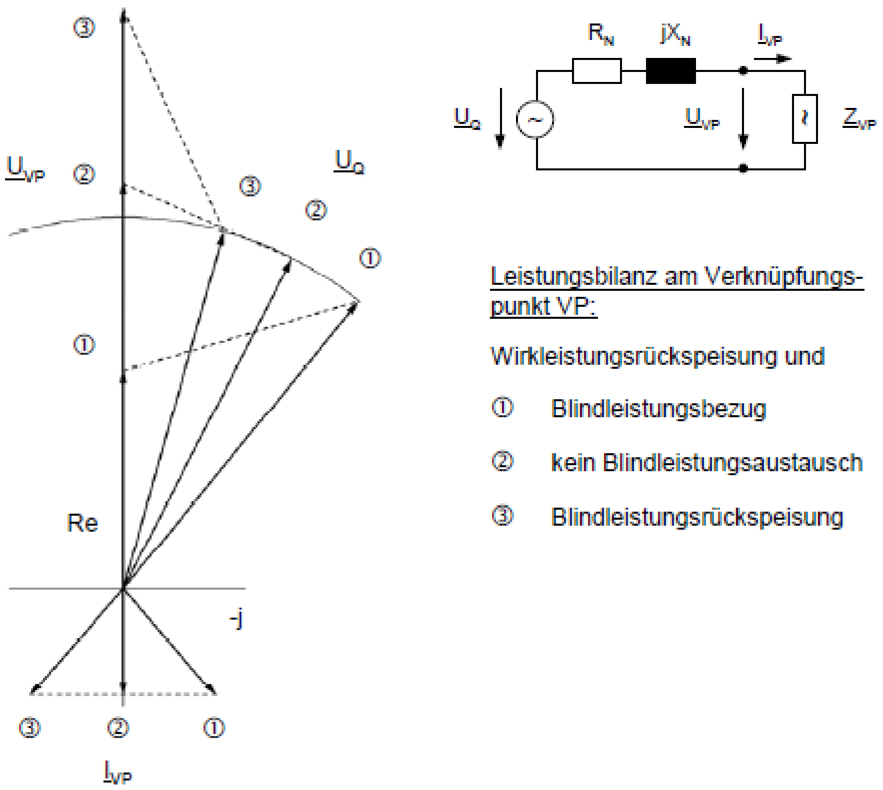

Illustration 5.2.3.b: Vector diagram for different power injection cases into a low voltage grid (case 1: reactive power consumption; case 2: no reactive power exchange; case 3: reactive power generation)

[Kerber 2009] discusses a reactive power delivery characteristic according to illustration 5.2.3.c. Within a band between 370 V and 430 V only active power is injected. In case of overvoltage an inductive current is injected with a linear increase to 100 % in case the voltage reaches 450 V. In case of low voltage a capacitive current is injected, again with linear characteristic reaching 100 % when the voltage decreased to 350 V.

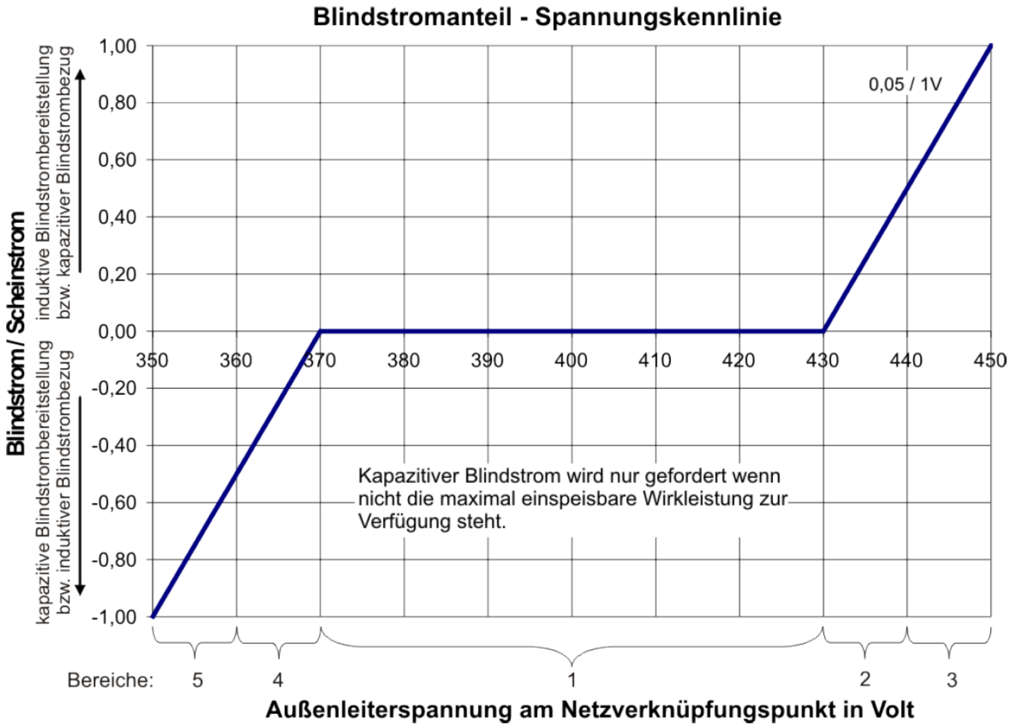

Illustration 5.2.3.c: Suggestion of a reactive power delivery characteristic (horizontal axis: voltage at inverter injection point; vertical axis: relation of reactive current to apparent current) [Kerber 2009]

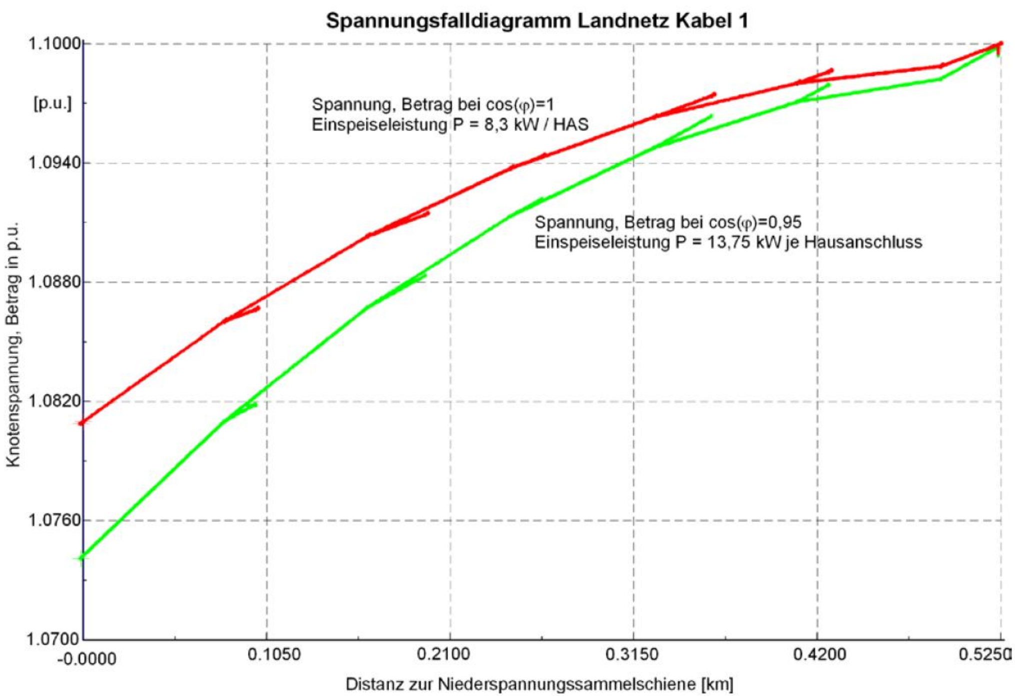

Illustration 5.2.3.d: Voltage characteristic on low voltage grid with PV inverter power injection, red curve: 8.3 kW per house with cos(ϕ) = 1, green curve: 13.75 kW per house with cos(ϕ) = 0,95$_{ind}$ (horizontal axis: distance to transformer in km; vertical axis: voltage in p.u.) [Kerber 2009]

Kerber investigated exemplary grids with identical injection powers at every house and increased the power injection until either the $\Delta U \leq 3\%$ criterion or $\pm 10\%$ criterion is violated. The investigated grid is a radial distribution string. The medium voltage side has been kept constant at 1.07 p.u. Illustration 5.2.3.d shows the results. With a cos(ϕ) = $0{,}95_{ind}$ the maximum power injection could be increased from 8.2 kW per house (with cos(ϕ) = 1) to 13.75 kW per house. That represents an increase of 65 %. At the low voltage side of the transformer voltage decreases due to the bigger load flow that causes especially voltage drops at the transformer impedance.

Solutions in case "asset loading" is the problem

The evaluation of typical grids has shown that loading of cables or transformer in most cases is the limiting factor. The following could be undertaken to increase the PV capacity that can be installed.

Solution "Asset Loading" 1: in case of a too small transformer a second one can be installed in parallel or it could be exchanged by one with a higher rated capacity.

In case the loading of cables is the problem it is not that easy just to lay a second cable as this action comes along with costly ground work apart from the pure cable cost. Therefore other actions need to be undertaken.

Solution "Asset Loading" 2: The current at the transformer could be measured. In case the current from the low voltage side to the medium voltage side is too high PV inverters could reduce power injection. This solution requires a communication infrastructure.

This measure could significantly increase the potential PV capacity as the theoretically assumed minimum load during maximum feeding-in is not very probable. And times with peak injection also are of short duration. Therefore, this measure probably only seldom need to be applied.

Solution "Asset Loading" 3: grid load is generally of ohmic-inductive nature. When inductive power is provided via the low voltage transformer means an additional load also to the cables. PV inverters can supply a reactive power in order to make a decentralized compensation. This reduces the load on the line and additional active capacity could be installed. This also reduces line losses at the same time.

The same communication mechanisms could be applied like it is already the case in the medium voltage grid nowadays.

Solution "Asset Loading" 4: Alternatively to the communication solution described beforehand power factor could be controlled decentralized to "1" at the injection point. Here, a communication with e.g. a smart meter would be necessary that measures $\cos\varphi$.

Solution "Asset Loading" 5: Again with communication at least with the low voltage transformer or even with PV inverters the medium voltage could be adopted in a way that low voltage is at its maximum allowed ($\pm 10\%$). With the same power injected the current is decreased when the voltage is increased.

Advanced solutions to increase PV power capacity in low voltage grids

In low voltage grids the relation of resistance load per unit length to reactance load per unit length is around 2.5. Due to this fact in opposite to high and medium voltage grids active power has a bigger influence on voltage drop than inductive power. Therefore, grid management via active power management is more effective than reactive power management. Active power management not only controls voltage but at the same time also the loading of cables and transformers.

Active power management solution 1: By demand side management respective load shifting in combination with smart metering loads can be shifted to times of high solar irradiation and therefore consume the power generated at the place or close to the place of generation. By this, both voltage increase and line overloading is prevented.

Active power management solution 2: Mobile battery storage in electrical vehicles. Batteries can be charged when solar power generation is high. With so-called plug-in-hybrids also a discharge in case of a power need could be realized.

Active power management solution 3: Stationary battery storage. Batteries can absorb excess power generation when the grid is overloaded. They can be discharged in a high load and low power generation condition.

Active power management solution 4: An increased number of buildings are heated with heat pumps. When heating systems are equipped with (cheap) heat storages heat pumps need not be operated in times of heat demand but can be operated when solar power generation is highest and therefore avoid overvoltage and cable overloading. The same could be realized with cold storages and air conditioning units.

Active power management solution 5: Finally, also direct electrical heating can be applied in times of too high solar power generation. With a heating rod hot water tanks can be heated in times additional loads are required for grid management.

6 Protection and Metering Issues

Protection of PV systems connected to the low voltage grid can be divided into protection issues for the PV plant itself (mainly blocking diodes and string fuses) and into issues related to safety issues for grid operation. For this study only the latter is of importance and discussed in the next section.

6.1 Protection issues for decentralized generators related to distribution grids

Originally, low voltage grids had been designed as pure distribution grids that are exclusively fed by the transformer station. With e.g. PV plants within the low voltage grid power flow can occur from many places – not only from the medium voltage side of the transformer. In order to protect service personnel from the grid operator when they work on grid assets it must be ensured that they can work safely on the grid without danger of an electrical shock caused by PV plants feeding electricity into the grid. This task is done in different ways, depending on the plant size.

PV power plants with a nominal power exceeding 30 kVA

For PV power plants connected to low voltage grids exceeding a nominal power of 30 kVA a circuit breaker with disconnection functionality with permanent accessibility is specified. That can be either

- An over ground access point of the house connection cable to the low voltage grid, or
- The house connection box in case it can be accessed by the grid operator personnel.

PV power plants with a nominal power less or equal 30 kVA

The majority of PV power plants connected to low voltage grids have a nominal power less or equal than 30 kVA. Differently, here circuit breakers with disconnection functionality can be waived in case the following is taken into account:

- The PV system is connected to the grid via a single phase inverter with a nominal power less or equal 4.6 kVA (systems bigger than 4.6 kVA must be connected to all three phases) that has implemented a voltage monitoring in all three phases, or
- The PV system contains an automatic disconnection unit (German: Selbsttätige Freischaltstelle) in between the PV system and the grid according to DIN VDE 0126-1-1. This unit is operating according to one of the following principles:
    - Impedance measurement
        - In case impedance measurement is applied an impedance step of 1 Ohm has to be selected.
    - Three phase voltage monitoring

    - In case the voltage decreases to values less 0.8 UN or increases to values more than 1.1 UN the inverter has to disconnect the PV system from the grid in all three phases – even only one phase is affected.
    - Only when the voltage has returned to the mentioned limits within all phases the inverter can reconnect the PV system to the grid.
  - Resonant circuit test

- The automatic disconnection unit can be an integral part of the inverter or can be installed separately.
- The frequency is outside the interval of f ≤ 47,5 Hz und ≥ 50,2 Hz
- The power factor of a house connection including the PV power plant must be in the range of $\cos\varphi = 0.9 capactive$ and $\cos\varphi = 0.8 inductive$
- The unbalance within different conductors must not exceed 4.6 kVA.

In the beginning of PV installations in Germany always accessible circuit breakers had to be installed. That has represented a large expenditure during installation. The waiver of circuit breakers with disconnection functionality has been a big step towards economic efficiency of PV power plants, especially those with a smaller installed nominal power.

When installing a PV power plant it has to be proven that the system fulfills the above mentioned criteria. In order to avoid testing this for every PV system installed so-called “Conformity Declarations” have been introduced. Inverter manufacturers provide them for their products.

6.1.1 Comparison of the protection costs with the total investment costs

Especially in smaller PV installations less than 30 kVA the protection devices according to chapter 6.1 are almost always an integral part of the inverter. Only in larger systems it is obligatory to have a separated switching device.

For the comparison of protection costs to total investment costs here external protection devices are taken into account and some examples are calculated with the assumption of overall specific system cost of 3,700 €/kW$_p$ (Table 6.1.1.a).

Table 6.1.1.a: Comparison of several protection cost shares

System Capacity [kW$_p$]	Protection unit	Protection unit cost [€]	Overall system cost [€]	Percentage of protection cost [%]
< 3.6	Tele Haase ENS VDE	102.00[12]	13,320.00	0.77

[12] http://www.mbw-electronic-online.de/Tele-Haase-ENS-VDE-0126-1-1 [September 30th 2010]

< 5.7	UFE ENS26	370.00[12]	21,090.00	1,75
< 30.0	UFE ENS32	850.00[13]	111,000.00	0.77

This analysis shows that protection costs are almost negligible when considered as a percentage of the overall system cost. For inverter integrated protection solutions the cost fraction is even significantly lower. Phone discussions with inverter manufacturers approve this but did not result in concrete figures.

6.2 Measurement of decentralized electricity generation

Operators of PV systems want to earn money by selling electricity to grid operators. Therefore, PV systems require the installation of one or several electricity meters. The exact configuration depends on several boundary conditions. Illustrations 6.2.a and 6.2.b are configurations where only the difference between generation and consumption are fed to the grid whereas in illustration 6.2.c a typical configuration according the German feed-in low is shown. The illustrations indicate the meter configuration and also the different safety devices.

Depending on the contract situation the following has to be measured:

- Electricity consumption of the customer loads
- Electricity consumption of the PV system itself (in stand-by mode during night or very low irradiation times the PV system can have a higher electricity demand than generation)
- Electricity generated by the PV system

The simplest meters can be used as feed-in tariffs are constant in time and do not vary with time of day or time of year.

The property of the meters is up to the decision of the plant operator. The meter can be owned by the grid operator. In this case the PV plant operator pays a rental fee to the grid operator. PV plant operators can buy and install their own metering devices. From an operator perspective the difference is the rental cost of 20 years compared to the meter investment cost (in practice most often rental is more expensive than buying one). In future with a liberalized metering market the meter also can be owned by a third party.

Independent from the model selected the meters installed need to be calibrated. In the feed-in tariff model applied meters need either to be equipped with a reverse lock or electronic meters are applied that are capable of measuring power flow in both directions.

In case of net-metering only one electricity meter has to be installed – that is <u>not</u> equipped with a reverse lock.

[13] http://neg4.de/pool/download/datenblaetter/ens32/ENS32_savings_en.pdf [September 30th 2010]

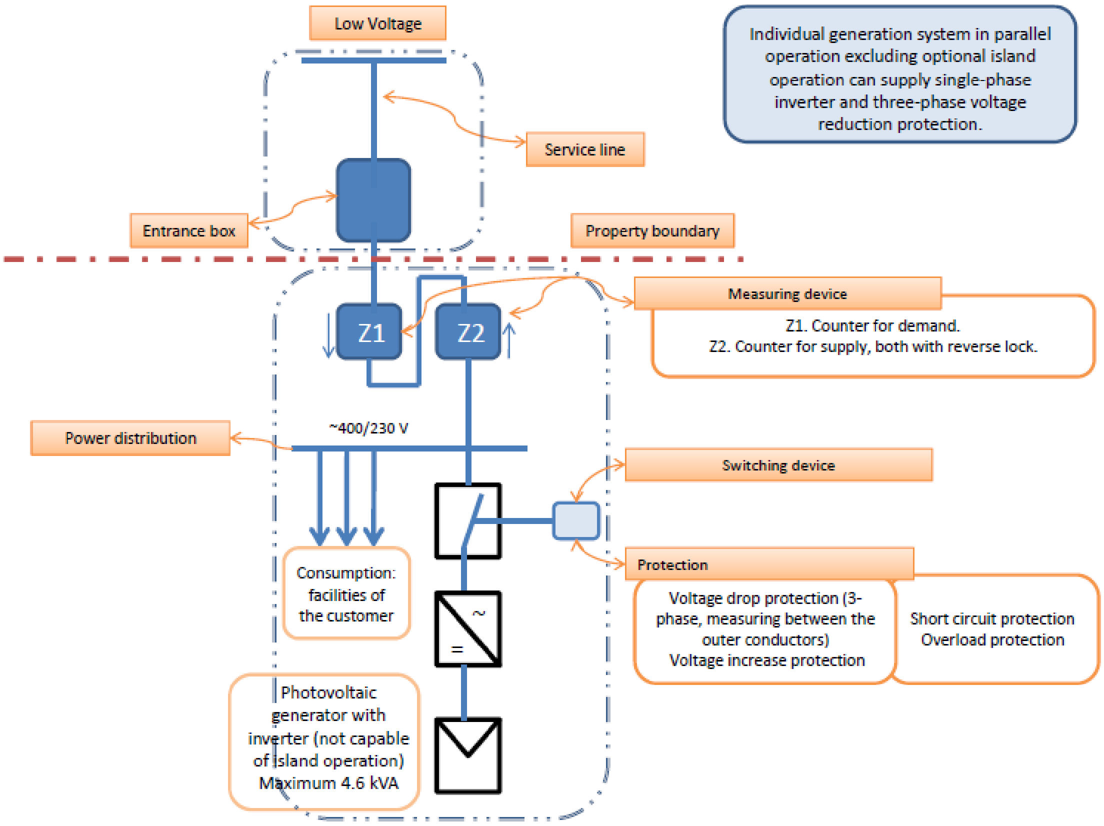

Illustration 6.2.a: Installation scheme for excess power feed-in with voltage drop and voltage increase protection as well as short circuit protection.

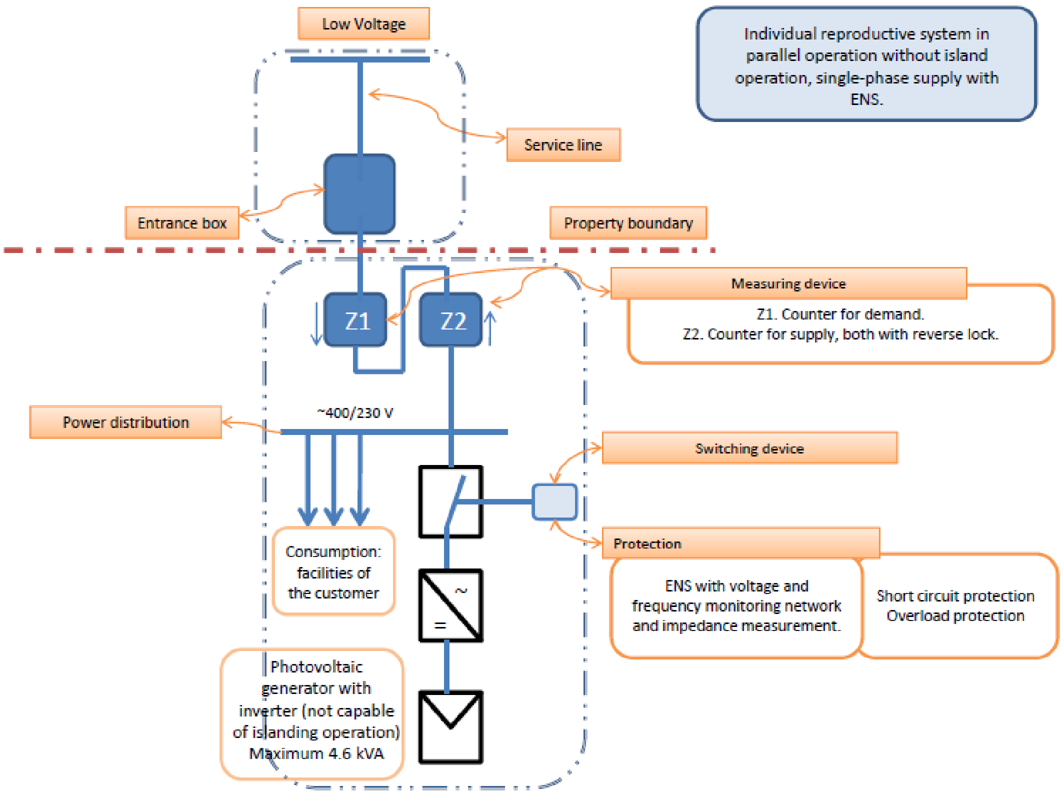

Illustration 6.2.b: Installation scheme for excess power feed-in with voltage, frequency and impedance measurement protection as well as short circuit protection.

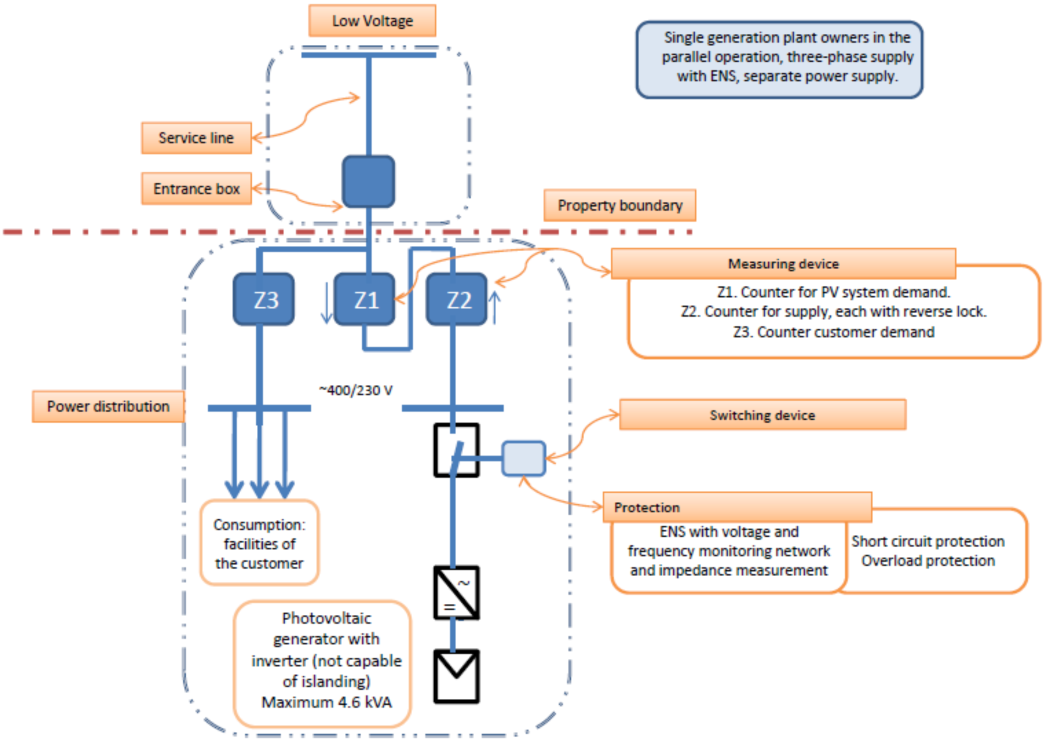

Illustration 6.2.c: Installation scheme according to German feed-in law with voltage drop and voltage increase protection as well as short circuit protection.

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