MSc Program
Renewable Energy in Central & Eastern Europe

Problems and opportunities by large scale integration of distributed generation and improvements by using ripple control technology

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“Master of Science”

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Affidavit

I, Walter Schlegel, hereby declare

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Abstract

Integration of distributed generation (DG) in Central Europe is a key element for future security of supply, adequacy and sustainable development of electric energy production. It also becomes more significance in the context of Smart Grid and the „20/20/20“ targets of the European Union climate and energy policy. Problems and opportunities are widely discussed and it is hard to get an overview and clear indications of the possibilities to increase the installed capacity of DG in distribution networks. Existing studies give already some indications of possible integration level of DG and together with a qualitative assessment of the problems and opportunities the implications in execution time and cost could be evaluated. The results show that the problems can be solved with additional investments but the lead time for this is in the range of several years. A DG capacity quota start to be problematic if it is larger than 25 % of DG compared to maximum load. The dominating influence is given by stochastic production and lack of control. The smart grid approach tries to tackle this problem but unfortunately with a long lead time, necessary for research, development, standardisation and financing schemes. Various pilot projects with smart grid approach exist but a wide-ranging transformation might be still a few years away. With the simple control functionality of ripple control, which is widely used in Europe, the capacity of DG could be increased with little changes up to 75% and more. This means, that in networks with already installed ripple control system this controllability could be used to reach a high degree of installed DG without lead time. The hardware cost for new ripple control receivers (e.g. with more channels) is negligible. However, the implementation of new business models and / or contractual arrangements can create relevant obstacles for the management and might need a change in attitude. In addition regulators should focus on incentive schemes to promote DG integration and storage facilities for electricity production from renewable energy resources.

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Glossary

AC	Alternating Current
ACER	Agency for the Cooperation of Energy Regulators
CAPEX	Capital Expenditure
CEER	Council of European Energy Regulators
CHP	Combined Heat and Power
CIGRE	International Council on Large Electric Systems
DG	Decentralized Generation or Distributed Generation
DSO	Distribution System Operator
DSM	Demand Side Management
DSP	Demand Side Participation
EC	European Commission
EHV	Extra High Voltage
ENTSO	European Network of Transmission System Operators
ERGEG	European Regulators Group for Electricity and Gas (now ACER)
EU	European Union
HV	High Voltage
Hz	Frequency, Hz = 1 s^{-1}
ICT	Information and Communication Technology
IEEE	Institute of Electrical and Electronics Engineers
kW	kilo Watt (1*10^3 Watt)
LV	Low Voltage
MV	Medium Voltage
MW	Mega Watt (1*10^6 Watt)
OPEX	Operation Expenditure
PQ	Power quality is a set of limits in electrical systems (EN 50160 standard)
RES	Renewable Energy Resource
SCADA	Supervisory Control and Data Acquisition
TSO	Transmission System Operator
UCTE	Union for the Coordination of the Transport of Electricity
VDE	Association for Electrical, Electronic & Information Technologies
VQ	Voltage Quality

Adequacy: ability of the electrical system to supply the aggregate electrical demand and meet energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities.

Quality of Supply: measures the quality of the electricity service provided to customers, usually in terms of acceptable voltage and frequency values.

Security of Supply: ability of the electrical poer system to provide electricity to end-users with a specified level of continuity and quality in a sustainable manner.

Stability: the ability of an electrical system to withstand normal and abnormal system conditions or disturbances and to regain a state of equilibrium.

Tap changer: device on a transformer that adjusts the output voltage of the transformer by changing the number of turns in the windings.

Reactive Power: generally expressed in var (volt ampere reactive) is the portion of electricity that establishes and sustains the electric and magnetic fields of alternating current equipment. Reactive Power must be supplied to most types of magnetic equipment, such as motors and transformers, and causes reactive losses in transmission facilities. It is provided by generators or electrostatic equipment such as capacitors and directly influences the voltage of the electrical system.

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1 Introduction

The market for electrical energy is very complex. On the one hand electrical energy is a consumer good which is available against a market price and on the other hand electrical energy is a regulated good with state controlled access. In Switzerland like elsewhere too, the utilities have the obligation to connect every household to the public grid and have to secure the supply of electrical energy. This circumstance of market driven, and regulated activities can create complex structures with complicated rules and finally great influence on the behaviour of the consumers. Electric energy seems to be available at any time in any quantity without restrictions, at least in western European countries. For the provider it is a driver for strong transmission and distribution networks, installing big power plants for base load, peak load and backup power production. Supporting renewable energy leads to small production facilities randomly distributed and stochastic production. This was leading to network problems and additional costs and the network companies, distribution operators, opposed against large penetration of decentralised generation. Due to lack of new large production sites and problematic transmission network enlargement the acceptance of decentralised production has grown but problems are still present or have even increased. This paper shall give an overview of the problems and highlight a simple solution with a standard technology.

1.1 Motivation

The idea of decentralised energy production is very old and therefore also the beginning of the electrical energy supply. After a period of centralising production and building strong transmission networks it becomes today more significance in the content of Smart Grid and the „20/20/20“ targets of the European Union climate and Energy policy. At the same time we discover a diminishing acceptance for building new transmission lines and large power plants. A dissemination of decentralised production of electric energy was long time hampered by putting forward technical reasons and also economical scepticism was popular. In the meantime many studies have been published and have shown that technical solutions are available and economical benefits can be expected. Nevertheless it attracts my attention during the study of the postgraduate course (Auer H, 2009) and my daily work that the variety of problems about decentralised production has even increased. The opening of the markets and the unbundling of network and production has lead to an additional complexity and cost drivers. Notwithstanding I am at the opinion that a raising portion of decentralised production could be achieved by applying existing standard technologies. In this paper I like to give an overview of the problems and highlight some solutions with related lead time and if available information on cost. As a practical solution I explore the effect of achieving higher concentration of decentralised production by using ripple control technology.

1.2 What is the core objective / the core question?

The objective of the paper is to find out if ripple control can increase the installed capacity of DG in distribution networks.

- What are the technical problems in installing DG?
- What solutions exist?
- What is the effect of each problem (time delay and cost)?
- What is the possible integration level of DG in MV and LV networks?
- Can ripple control technology help to overcome some of the problems and increases DG quota?

1.3 Citation of main literature

- DG DemoNetz – Konzept; Bundesministerium für Verkehr, Innovation und Technologie, Wien, H. Brunner et al. 12/2010
- Systemvergleich von Strom- und Wäremeversorgung mit zentralen und dezentralen Anlagen, Paul Scherrer Institute, PSI und Axpo Holding AG, CH. Bauer et al. 12/2010
- Technisch wirtschaftliche Systembetrachtung zur netzorientierten Integration von Mini-Blockheizkraftwerken. Dissertation an der Technischen Universität Carolo-Wilhelmina zu Braunschweig, M. Pielke 2010
- KWK-Erzeugungsanlagen in zukünftigen Verteilnetzen – Potenzial und Analysen, Dissertation an der Universität Dortmund von von E.Hauptmeier
- Wirtschaftlichkeit dezentraler Einspeisung auf die elektrischen Netze der Schweiz. Bundesamt für Energie, Bern 2010; CONSENTEC und Polynomics

- Studie „Dezentrale Erzeugung in Österreich“ E-Control 2005
- Dispower, Distributed generation with High penetration of Renewable Energy Sources, Final Public report, 2006
- Smart Distribution 2020 Virtuelle Kraftwerke in Verteilungsnetzen, VDE (ETG) 2008
- Technical information’s from DSOs, Associations and manufacturers.
- DG Energy web platform Smart grid and CEER/ACER web platform.

1.4 Structure of work

- Definition and description of the problems
- Description of the solution with information about execution time and costs
- Assessment of impact of problems and solutions on increase of DG
- Assessment of limiting factors
- Optimisation potential by using ripple control

Methodology:
For the problem and solution study mainly literature research is used. The assessments are done by qualitative comparison, benchmark and interpretation which are visualised in a matrix similar the portfolio analysis according to Boston-Consulting-Group-Matrix.

2 The electrical system

2.1 Historic evolution of electrical networks

The development of engines, starting with steam engines, was the driver of the industrial revolution. The possibility to use powerful machines instead of human kind workforce very rapidly introduced new work procedures and processes. The development of electric machines was only one step forward in this development. Naturally the production of the electricity was in the beginning very close to the consumer. So were many waterwheels with belt transmission systems converted to

water turbines with generators and small distribution networks. The networks were very small and most of the time only powered by one power plant.
Alfar Edison started local electric networks which were based on DC technology. But with the technical development of the machinery, bigger power plants were possible and wider areas of consumers could be supplied and the AC technology, invented by Nicola Tesla, made the race on future network development. The demand in urban localisations raised faster than in rural zones and the distance between power plants, especially hydro power to the cities defined the strategy of electrical networks. In the years followed it was only a natural development of network topology following the consumer demand and power plants.

2.2 System description

For the approach to the question of how to increase decentralised generation the system has to be defined first. A mainly technical based system is determined by components which interact in processes with each other and can been seen as a coherent object. It interacts with its environment in both directions. That means it can be influenced (controlled) and reacts with a specific output. A car or a power plant can be seen as technical system with clear purpose and interaction with its environment. The question now is, is an electrical network with producers and consumers a simple technical system?

In the past the producers had their own network and were building a system supplying the customers based on a clear demand request. The system “electricity supplier” managed the production and distribution within its system borders could be seen from outside as a system supplying electricity. Because of the lack of a free market for the commodity electricity this was combined with a monopoly. So the answer would be more or less YES.

Today the unbundling of the old system has been decided and is already in a advanced status. According to (Scheepers, 2005) the electric system can be divided into two subsystems, the physical and the commodity subsystem.

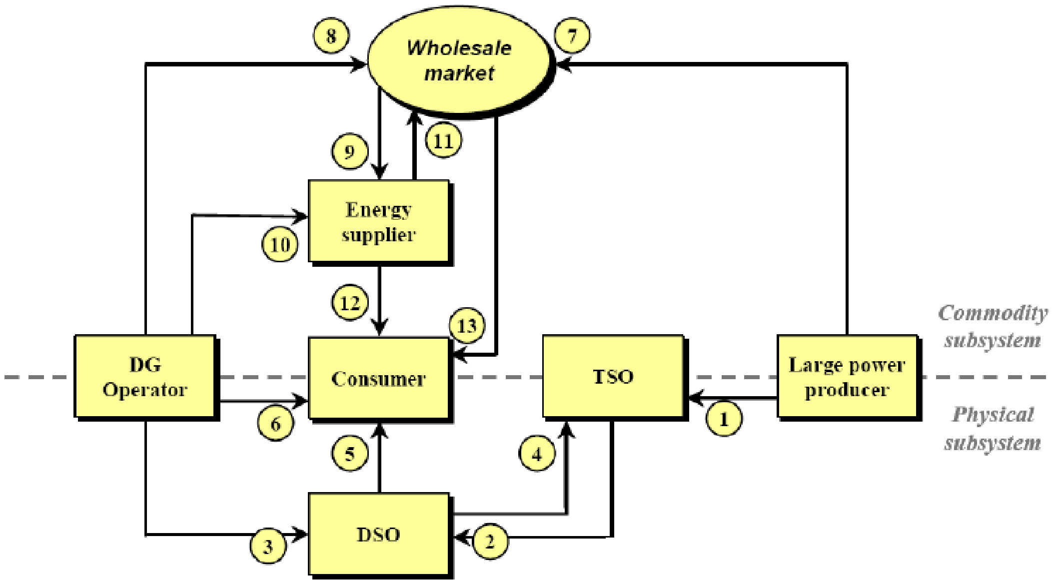

Figure 1, elctricity marketmodel, source: (Scheepers, 2005)

2.2.1 The Commodity subsystem

The commodity subsystem has been well integrated in the physical subsystem in the past but the unbundling process has created new elements. Wholesale market places were large power producers and DG operators offer their electricity (relation 7 and 8) and Energy suppliers get the right to use the electricity against a bid (relation 9 and 11). DG operators can also offer directly to the Energy suppliers (relation 10) and mainly large consumers can participate directly in the wholesale market (relation 13). The consumer finally gets the right to use the energy, supplied by the physical subsystem, from the energy supplier (relation 12).

2.2.2 The physical subsystem

The physical subsystem basically consists of hardware for production, transportation, distribution and consummation of electricity. The elements involved are the Transmission System Operators (TSO), the Distribution System Operators (DSO), large power producers, consumers and Distributed Generation (DG) operators. The large producers are connected to the transmission grid (relation 1) there the DGs are connected to the DSO grid (relation 3). The TSO supplies the DSOs with electricity (relation 2) and further down the chain to the consumer (relation 5). The physical subsystem is now regulated, system charges and connection fees are guaranteeing the payments for the services provided by the network operators (relations 1 to 5). Where electricity is produced locally it can also be used by a consumer directly without using the networks (relation 6).

Today the electrical networks are generally divided into two groups. Networks with nominal voltage above 52 kV are called Transmission-, and networks between 1 kV and 52 kV are called Distribution Networks. The networks where households are connected to are so called low voltage networks with nominal voltages of 230 resp. 400 Volt in the 3 phase, 50 Hz system.
The transmission networks are used to connect big power plants (> 30 MW) and for electrical energy exchange between regions, big cities and countries. The distribution networks are used for connection of power plants between 1 and 30 MW and for energy exchange between small cities, industrial areas and rural districts. Low voltage networks are only used in local residential and small industrial areas.

The classification in network levels 1 to 7 is used to describe the hierarchy of electrical networks and is shown in figure 1together with the associated power which is typically available on each level.

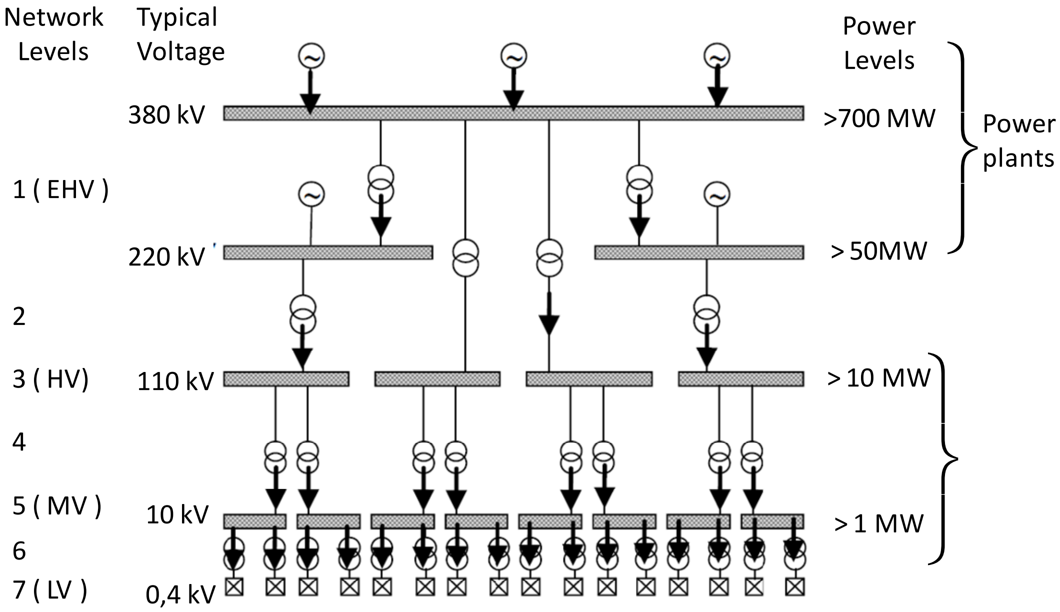

Figure 2 network levels

If we look at an electric network on a large scale (like UCTE network) we find all power production sites somehow decentralised and distributed. The term distributed generation (DG) needs therefore to be more clearly defined. The following definition by (Ackermann et al, 2001),"*Distributed generation is an electric power source connected directly to the distribution network or on the customer site of the meter*" will be used and categorised as per table 1.

Table 1 categories of DG

Micro DG	~ 1 Watt < 5 kW
Small DG	5 kW < 5 MW
Medium DG	5 MW < 50 MW
Large DG	50 MW < 300 MW

The design and operation of Transmission Networks is different to Distribution Networks. Transmission Networks are normally designed for connection of power plants and are also controlled via a SCADA system. Distribution Networks on the other hand are normally designed to have only loads and are not fully supervised and controlled. The main problems of integration of DG can therefore be found on the Distribution Networks with DG of categories Micro and Small. The following chapters will deal only with DG in Distribution Networks, network levels 5, 6, and 7.

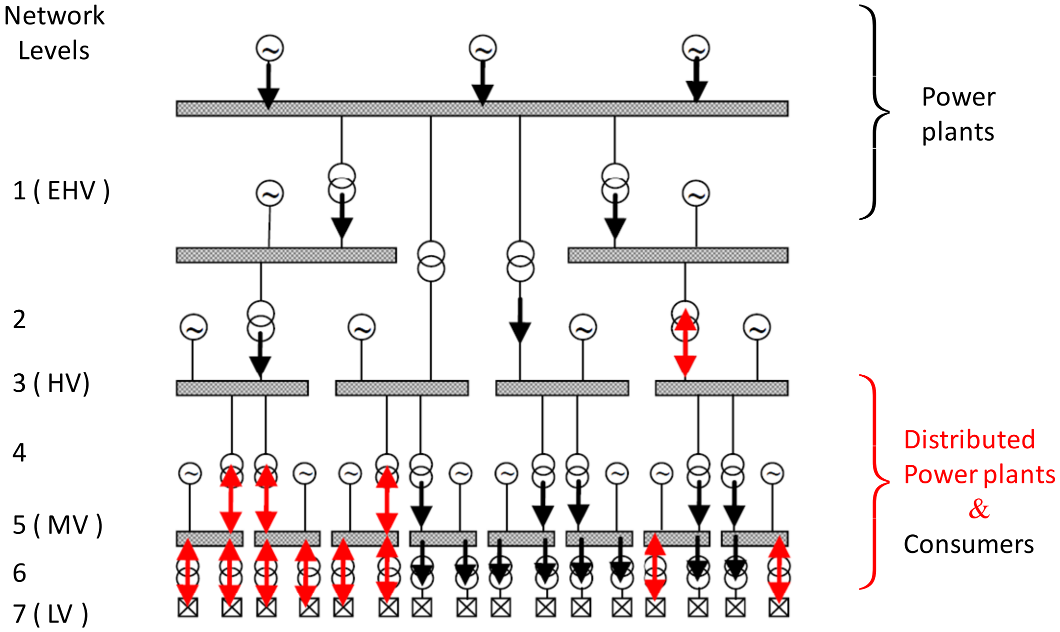

Figure 3 network with DG

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Since the early 80's, driven by the first oil crisis the idea of generating electric power by small decentralised units from renewable sources became a topic in the utilities. For a long time the amount of decentralised installed power units was very small and standards and procedures for grid connection were given by the local utilities case by case.

The discussion on CO_2 enrichment in the atmosphere and related climate change, political changes in supporting renewable energies and generous feed in tariffs gave now the final drive into the bigger scale integration for decentralised production units. National and international standards for grid connection and procedures are now under discussion and many R&D projects have been launched so far.

3 Identifying the problems of integrating DG in existing networks

According to the EU research project DISPOWER (Degner et al, 2006) the following technical impacts on power systems were identified:

- Quality of supply and power quality at the customer point of connection
- Grid control and stability of the overall network
- Safety and protection of the overall network
- Change of dispatch and economics of centralised power plants of non-DG electricity producers.

3.1 Quality of supply and Power Quality (PQ)

The quality of a service of an electrical network to customers is determined by several factors there the voltage and the frequency are the leading variables. The ideal form of the PQ is based on sinusoidal Voltage with a frequency of 50Hz in Europe. In a network with suppliers and consumers exists a joint responsibility to maintaining a satisfactory PQ.

Voltage and frequency are in general representing the quality and stability of the network. In large networks, like the European EHV network, the frequency is very stable there the voltage can vary depending on the local network structure (Congestion) and load / generation situation.

Voltage and frequency in an electrical network are monitored and regulated from top down in the transmission network by the transmission system operators (TSOs). Normal- and maximum / minimum levels for the synchronic zone of the central European transmission network (network level one) are defined by UCTE. The specification of voltage quality on the consumer side connected to the network levels 5 and 7 are given by the European standard EN 50160. This standard gives minimum requirements in public distribution networks at the points of supply. Actually specified for slow changes within 95% of the time in one week is ±10% of nominal voltage and ± 1% of nominal frequency. Further specified are short duration voltage disturbances like flickers, sags and longer time interruptions, as well as unbalance and harmonics. The DSO has to take measures to keep the values inside the given standards. Based on this obligation and considering his own network characteristics every distribution system operator has its own specification of how to connect consumers and producers to the grid. In Austria, Germany, Czech Republic and Switzerland there exist technical rules for the assessment of network disturbances (DACHCZ, 2007) as a guideline for DSOs to deal with network connection issues and maintaining EN 50160 standards. The traditional development of electrical networks where the power flow is top down has lead to a specific problem of voltage increase by connecting DG.

3.1.1 Voltage increase in distribution networks with high penetration of DG

Any current in an electrical network with AC induces a voltage across the resistance of the networks elements. As in AC networks the elements have real and imaginary terms which are expressed as Impedance $Z = R + jX$. This voltage is either decreasing or increasing the network voltage depending on the power flow.

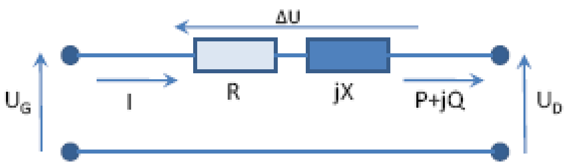


Figure 4 AC network element

The voltage on the EHV and HV network (levels 1 and 3) is generally carried by large power producers with synchronous machines and voltage variations along the network elements can be controlled by voltage regulators on the transformers (tap changers) which are able to vary the voltage in steps of 1 % between values of ± 5 to 10% of the nominal voltage. Due to the fact that traditionally power flow was considered from large power plants connected to the transmission network down to the consumers connected at network level 5 and 7 the last transforming between MV and LV (network level 6) was not equipped with tap changers. The last possibility of controlling the voltage is therefore at voltage level 4. The transforming to the last voltage level was on a fixed ratio considering the load and the voltage limits within the standards. In figure 5 we see an example of a network with two strings and in figure 6 the voltage along these strings.

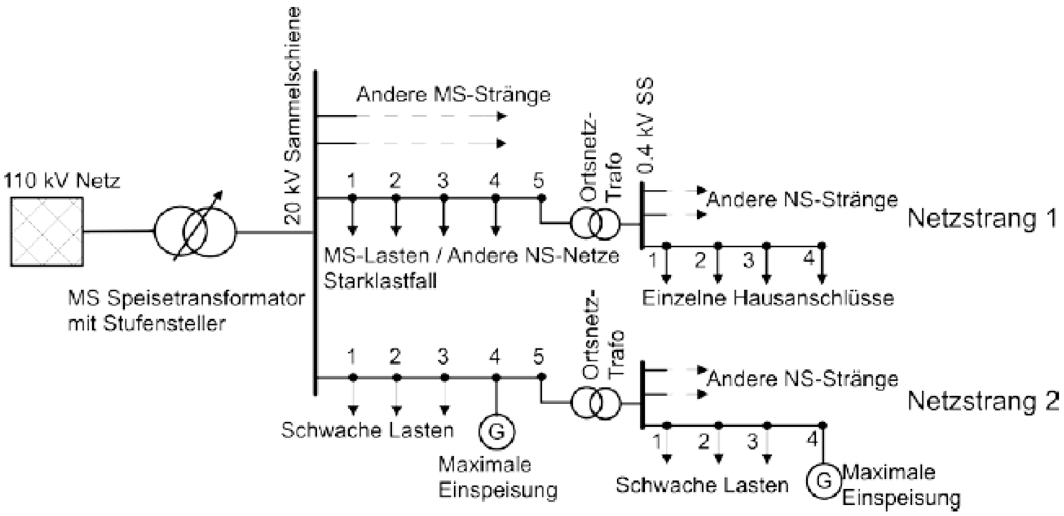


Figure 5 simplified network with 2 strings on level 5 to 7 (Kerber, 2009)

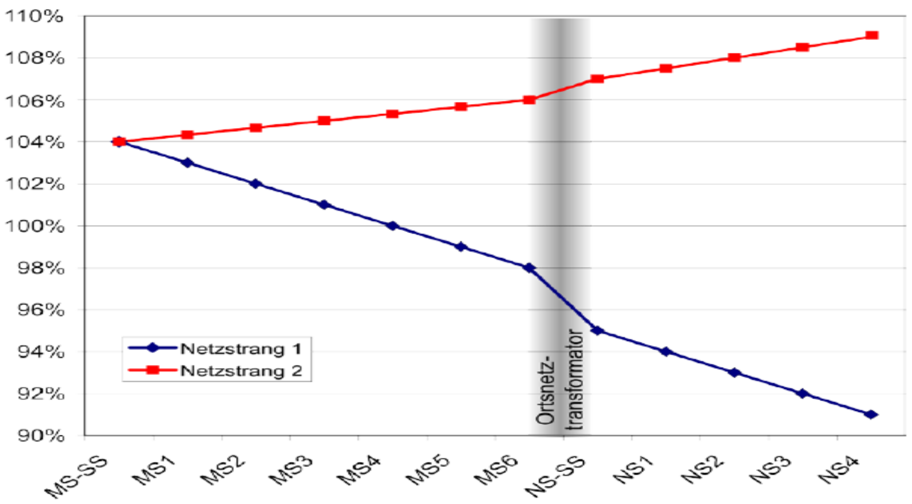
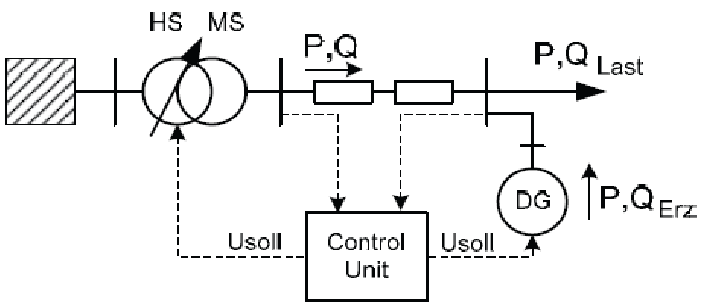


Figure 6 voltage levels along the two network strings (Kerber, 2009)

We can see what happens if we connect DG to one of the two network strings. String one has only loads connected and string two some DG. The worst case is shown in Figure 6 where string one is fully loaded and string two is with minimum load but maximum generation. The actual voltage increase, allowed by the guidelines (DACHCZ, 2007) is 3% and as the example in figure 6 shows this can be exceeded in networks with DG.

3.1.2 Solutions for voltage control in distribution networks

An extensive study and pilot project has been done under the program DG DemoNetz (Brunner H, 2010). In this program three different networks have been studied and the project team developed four innovative voltage control concepts which enable the network to operate within the limits with a high number of DG integrated in the network. The economic results of the study consider only the cost side of the concepts since it was considered that the revenues are equal to all of the four solutions. The most promising solution was found to be the coordinated voltage control. By this solution the tap changer on the transformers on network level 4 are used to vary the Voltage. They are normally already installed but controlled from the HV – SCADA control (higher network levels).



- HS = high voltage network (level 3)
- Transformer on level 4
- MS = medium voltage network (level 5)

Figure 7, coordinated voltage control, source: (Brunner H, 2010)

The solution requires some communication facilities between network stations and DG locations. This communication could also be used for coordinated protection (see chapter 3.2) and coordinated load management. This technical solution considers DG in the medium voltage network. A possible increase of DG in the low voltage network has not been considered and would be on top of the possible level of installed DG as shown in table 2. The table summarises the results of the study from (Brunner H, 2010). It shows, that by a indicated increase of DG (in MV network), the costs would only be 15 to 70% of conventional network reinforcement by implementing this solution (the savings therefore 85 to 30%). The possible increase in each network was not equal and also the savings were not comparable. This shows clearly that each network has to be analysed individually.

Table 2, main results of DG penetration and cost savings in (Brunner H, 2010)

Network types	**Already installed DG (% of max. Load)**	**Possible level of DG (% of max. Load)**	**Cost / savings (% of conventional network reinforcement)**	
Network 1	60	90	15	85
Network 2	24	56	30	70
Network 3	49	68	70	30

As a solution to improve the voltage situation in the low voltage network (Witzmann, 2010) and (Kerber, 2009) have shown that reactive power (Q(V)) regulation of DG can improve the voltage situation in the network and the new technical guidelines from BDEW (Bundesverband der Energie- und Wasserwirtschaft e.V.) ask for static voltage support and dynamic network support in the future (between 2010 and 2013) for MV network connected DG. The static voltage support in LV networks is under discussion and could be introduced in 2012. The effect of reactive power support by PV is shown in (Degner, 2010) and illustrated in figure 8. The increment in installed DG by PV is obvious even with fixed cosphi without additional network reinforcement.

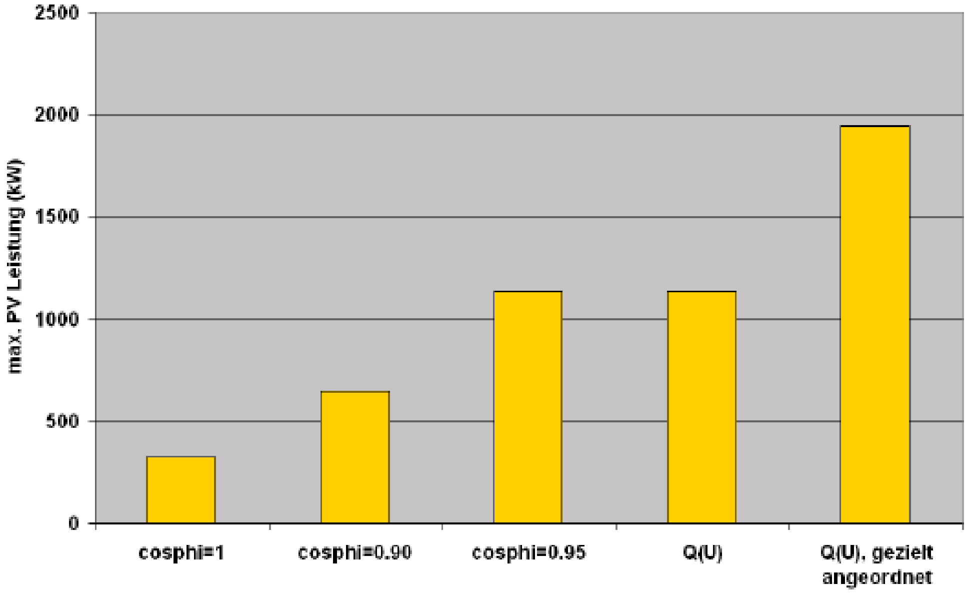


Figure 8, increase of installed PV by providing reactive power, sourde: (Degner, 2010)

The cost for additional V(Q) regulation in PV-inverters is not known to date.

3.1.2.1 Cost for network reinforcement

The net present value of the reinforcement in the medium voltage network is according to (Dg DemoNetz) 350 €/kW (including operation cost). For reinforcement cost for low voltage networks an average value according (DENA, 2007) of 21 €/kW can be considered and as operation cost only the metering cost will be applied with approximate 7 €/measuring point and month. For a small DG with 3 kW this is roughly 28€/kW/a. This cost would appear anyway for a household but for comparison this operation cost are considered for small DG. For DG above 30kW there is an obligation in Switzerland to install load measurement. This increases the cost to 500 €/measuring point and year[1] which leads to a cost of 17€/kW/a which is in addition to the normal measuring cost of a standard household connection.

Net present value of investment $NPV_n = \frac{IN_i}{(1+r)^n}$

IN = investment; R = interest rate = 2%; i = year of installation; n = year of use = 40

Operation cost cumulative $OC_n = \sum_{i=0}^{n} yc_i \frac{1}{(1+r)^i}$

yc = yearly cost (without price increase)

total cost (net present value) $TC_n = NPV_n + OC_n$

The values in table 3 are based on values above and are showing the net present values including operation cost for 40 years for DG sizes later used in this paper.

Table 3, indicative values of net present value for network reinforcement

Network and size of DG	NPV incl. Operating cost [€/kW]
MV / ≥ 500 kW	350
LV / 2.73 kW	186
LV / 3.85 kW	133
LV / 8.3 kW	64
LV / ≥ 30 kW	334

The figures are only of indicative use since network reinforcement can vary significantly depending on specific network configuration and situation of DG and have to be calculated individually for each project. A reinforcement and operation

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[1] ElCom Communication from 12. Mai 2011 „Messkosten und Zugriff auf Messdaten“

cost per kW seems to be optimal on low voltage networks with DG around 8 kW and highest if the installed capacity is ≥ 30 kW with connection to the LV or MV network.

3.2 Safety and protection

3.2.1 Short circuit power and island operation

As explained in the previous chapters, the electrical network is developed and structured top down. That means from production facilities to transmission and distribution down to consumers respectively loads. Since the power flow is clearly defined from top down the protection devices used for security are specified for this only. Also all parameters used to describe the safe switching off during fault conditions are based on this top down structure. One of the most common faults are the over currents due to short circuits to earth or between phases. In order to have a clear over current in case of short circuits the power to drive this current must be big enough. For this reason the utilities are dimensioning the short circuit current capability of power plants in the range of 20 times (2000%) the nominal current [VDE]. Frequency converter coupled DEA’s can only provide approximately 20% over current (island converter can drive up to 500% of nominal current for 100ms, source SMA). High penetration of DG, especially with converters, in networks can lead to smaller short-circuit power and therefore to malfunctioning or none functioning of conventional over current protection systems, On the other hand, additional short circuit power from lower or the same network level can overload the switching device.

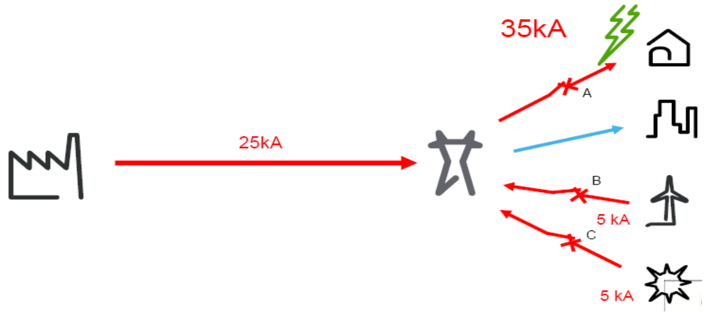

Figure 9, overload on switch A due to In-feed from B and C

Island operation of a part of the grid with DG is possible when a fault in the network has triggered a disconnection of a branch where DG is located. This intentional islanding is forbidden in public distribution networks. Small DG is normally not equipped with voltage and frequency control and the islanded network may operate outside of allowed limits which could lead to damages and malfunction of equipment. Another problem is the reconnection of the related network branch. This needs synchronising equipment on the islanded branch which is in normal cases not installed. A switch on in unsynchronised condition would cause severe damages to equipment and connected DG.

The problems are of different natures and in general some additional equipment is necessary. The minimum solution might be the change of fuse to a circuit breaker and the maximum solution is the fully coordinated protection scheme with distance protection at DSO level and inters trip communication between the relays. Figure 10 gives an idea of the location of the protection devices in a DSO network with DG.

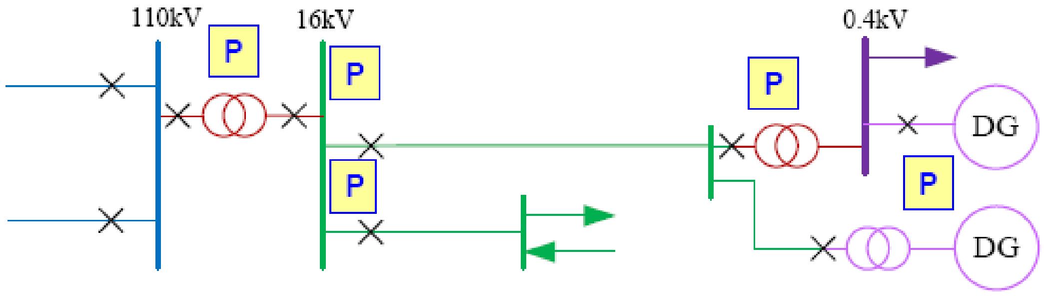

Figure 10, protection devices on a DSO network with DG

To solve the problems the following measures could be implemented

- more circuit breakers instead of fuse switches
- more protection devices
- in consequence more voltage and current sensors
- more communication for intertrip and control

The costs for coordinated protection systems (controllable switch with protection functions) are shown in table 4 and are approximate values based on (Hauptmeier, 2007) and projects executed by the author.

Table 4, estimated cost of coordinated protection systems, source: (Hauptmeier, 2007)

Location of the system	**Price in CHF / feeder**
MV Level (16kV)	43’000
NV Level (0.4kV)	6’000
Commercial connection point	3’500
Domestic connection point	2’500
Single small DG	1’500

3.3 Grid control and stability

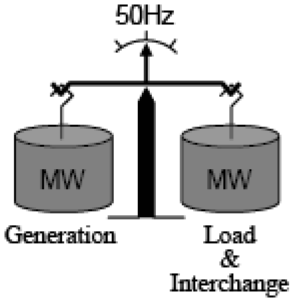

Figure 11 frequency balance

Grid control mainly means controlling the power flow were grid stability means ensuring a safe and stable network mainly guaranteed by keeping the two variables frequency and voltage within specified limits. In the previous chapter the thematic of voltage was described looking at the supply point of the network (network levels 5 to 7). Grid control and stability is mainly a task provided by the TSOs and big DSOs with a meaningful amount of power plant connected to their network. The balance between production and consumption is a condition for a stable electricity grid and means the coordination of these two influencing variables. Synchronous generators used in conventional power plants are relatively easy to control. Small distributed generation from renewable in the contrary is difficult to predict and control from remote. Load and cross border interchange on the other hand can be estimated but never accurately predicted. The IEEE/CIGRE joint task force on stability terms and definitions defines the power system stability as follows: "*power system stability is the ability of an electric system, for a given initial operation condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact".*

To guarantee the requirements on a stable network so called Balancing Authorities have been defined. At European level these are the national TSOs acting within their national borders.

3.3.1 Balancing services – grid stability

3.3.1.1 Market model of balancing

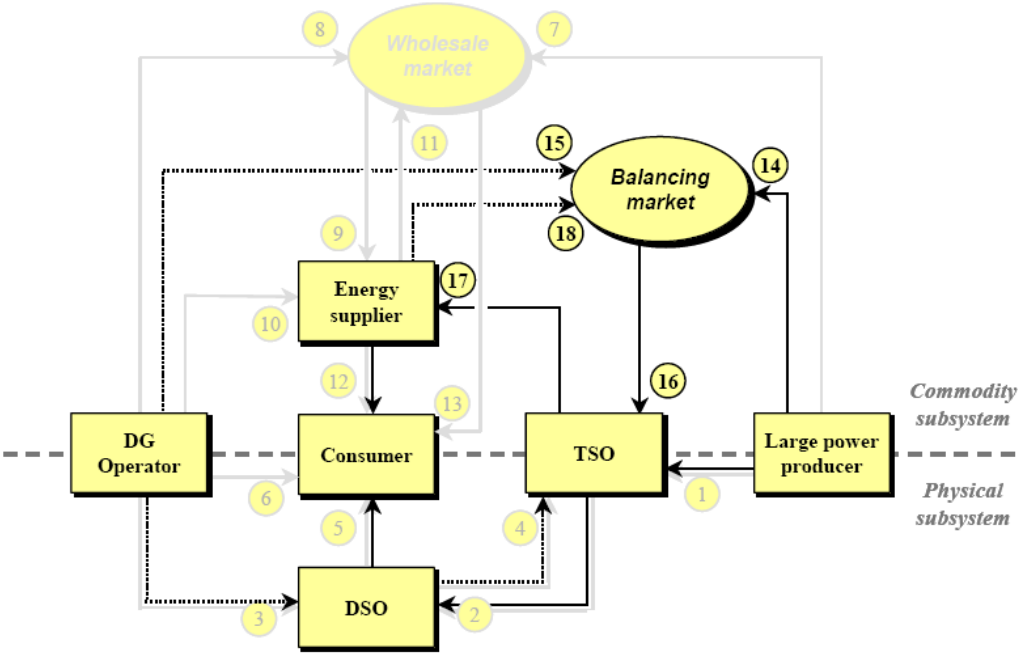

Figure 12, the balancing market, source: (Scheepers, 2005)

The balancing of the electric system today is organised by the TSOs. They buy balancing energy if needed based on offers made (16) on the balancing market. On this market place mostly large power plants offer their capacity and energy (14) but energy suppliers (18) as well as DG operators 15) can participate too. The TSO charges the balancing group which caused the imbalances (17) with the costs for this service.

3.3.1.2 Operational process of balancing

The Balancing Authorities are defined as a control area which maintains the frequency by balancing load with production. The TSOs organised within UCTE, which is now replaced by ENTSO-E, have agreed on a procedure of maintaining the frequency. It is based on a stepwise procedure which is shown in Figure 13.

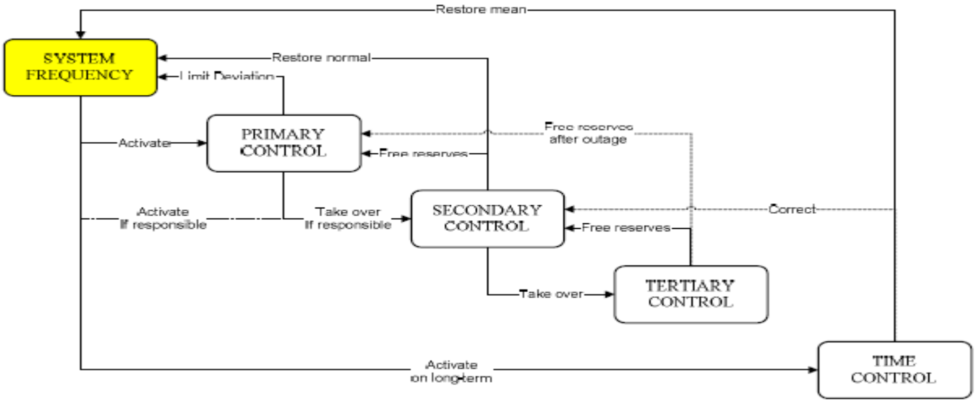

Figure 13 Control mechanism for the system frequency according UCTE

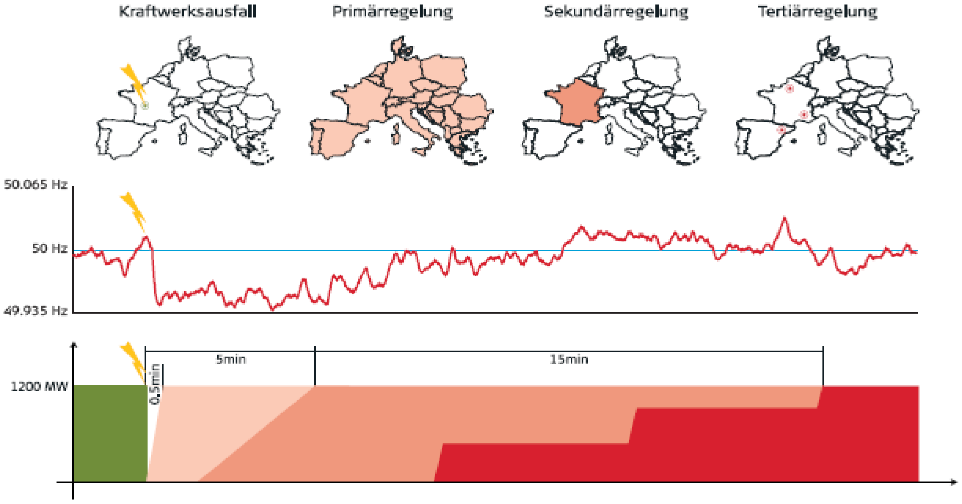

Figure 14 Example of control sequence after power plant failure

The figure above shows the time relation and actions taken in Europe based on a power plant failure in France. The primary and secondary reserves are automatically activated whereas the tertiary reserve is mainly activated manually by the dispatch centres. Balancing services are a main task of any TSO and power plants directly connected to network level 1 are generally forced to contribute to the balancing services. The services for secondary and tertiary balance are normally allocated to the providers based on a auction for energy and power. The amount of balancing power is determined based on the types and sizes of the power plants in the balancing area. Conventional power plants are fully controllable and therefore planning is easy and only faults, unplanned load and random in program inaccuracy are defining the necessary balance power and energy. With increasing portion of decentralised power production based on renewable energy the planning of production is becoming difficult. Independent of the increased predictability by

simulation software of weather conditions there will be an increased risk in forecasting and therefore higher demand of balancing power and energy.
The secondary control power was in the recent years almost used up to its full amount during certain hours of the day. This was mostly due to the hourly steps of the schedules (see next chapter), based on the international trade process which has hourly products as minimal products and the balance group schedules which were based on ¼ hour steps. This has been tackled by new ENTSO-E rule of using a 10 minutes ramp for schedule changes which has been introduced in 2010.

3.3.2 Scheduling and power flow – grid control

The grid control means mainly having the demand and supply in balance. There the balancing mechanism is designed to handle the short term variations and unplanned events the scheduling is the process to keep the network in balance. This process is based on the principle that all producers and consumers connected to a network are arranged in balancing groups. Each balancing group (BG) has to nominate a balance group manager (BGM) which has a contract with the TSO and is responsible for the equilibrium of the power balance within his group in each 15-minutes measuring period. The BGM is allowed to do the following business:

- trade energy with other BGM
- accept energy from power plants
- supply energy to consumers

The TSO on his side is responsible for the correct planning of the power flows and has a scheduling process which is harmonised within a common regulation zone (like UCTE). During the scheduling process all information from the BGM are collected and balanced together with all cross border trade. This process is ruling and basically organised in two steps following the trading schedules on the energy markets which are:

- long term energy trade and capacity rights, yearly, monthly products
- day ahead, hourly products

This scheduling process takes place in the day before delivery. The BGM have to supply their schedules until 14:30. The TSOs can coordinate and optimize with cross border schedules and open afterwards an additional trade window, the intraday market. This allows trade and schedule changes during the day of delivery (hourly products) and is especially of importance for BGM which has inaccurate schedules either for load or production. On lower network levels there are often loads with so called “normalised load curves” installed and the real-time behaviour of the load is not measured and leads to inaccurate schedules. A schedule of BGM must be balanced over a period and imbalance leads to costs or revenues depending on the situation in the control area. Table 5 shows the clearing system with related costs and revenues which will be applied. The factors are chosen to give the incentives for the BGM to support the control area in stabilising the system.

Table 5, imbalance clearing system, Swissgrid 2011

🟩 BGM has stabilising effect		Control area	
🟥 BGM has de-stabilising effect		short	long
Balance group	short	🟥 BGM pays $P_{imb-import}$ * A	🟩 BGM pays P_{spot} * A
	long	🟩 BGM receives P_{spot} * B	🟥 BGM receives $P_{imb-emport}$ * B
Legend	long = surplus of power short = deficit of power $P_{imb-import}$ = Price the control area pays for reserve power $P_{imb-emport}$ = Price the control area receives for reserve power P_{spot} = price on Energy on the sport market A = multiplication factor, actual (2011) 1.3 B = multiplication factor, actual (2011) 0.7		

3.3.2.1 Load curve

In addition to this financial risk of being imbalanced the DSO is also charged by the upper level network based on the peak load. According to Swiss law the commonly applied distributed network tariffs of distribution networks are divided into two portions (Art.16, StromVV). 70% of the network costs are based on the average of the monthly peak of the direct connected consumers of the network and the lower networks connected to this. 30% are charged based on energy consummation per kWh.

The Peak / Base load behaviour of a consumer or DSO is therefore relevant for their network tariff to be paid, respectively paid by the consumers connected to the DSO network. Figure 15 shows examples of load curves of a medium sized DSO typical for Switzerland (160 GWh supplied energy in 2010). The load curves are generally higher in winter and the base peak ratio can be as high as 1:2.

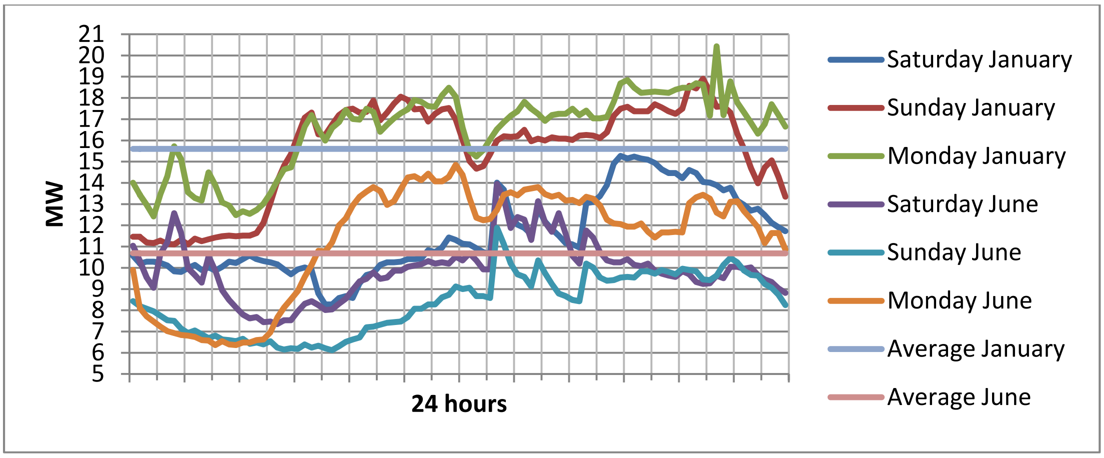

Figure 15, load curves of medium sized DSO in Switzerland (EWS)

To evaluate the commercial impact of the load curve an example with four different supply groups are chosen. The tariffs are taken from a large DSO in Switzerland which supplies smaller DSOs and customers in a range from large consumers down to households. The network tariff is compiled on a portion based on maximum power and a portion based on Energy consumption. This leads to different tariffs for groups with a more base-load behaviour and others with a more peak-load behaviour. The division is depending on the quotient of the yearly consumed energy and the average of the monthly peak. The quotient has the unit hours and if it is > 3000h this means it's more base-load characteristics and if it's ≤ 3000h it's more a peak-load characteristics. Each of the four groups is now calculated with two scenarios. The first is leading to base load characteristic and the second to a peak load characteristic. The energy consumption in each scenario is equal but the peak ration is 1:2. The tariff in figure 16 is calculated by the yearly cost divided by energy consumption. The tariffs for peak load are obviously higher than for base load. Since the energy consumption in each group is equal there is a cost saving expressed as the product of the energy consumed by the difference of tariffs. Table 6 shows the results based on the example calculated.

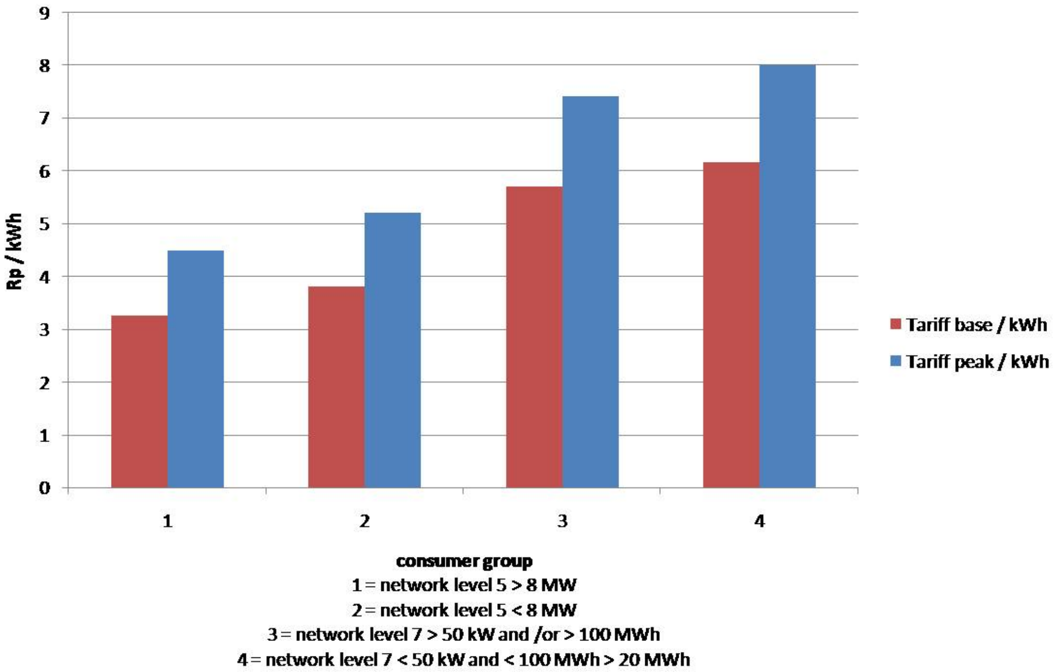

Figure 16, comparison of network tariffs based on load curve (base / peak)

Table 6, yearly cost savings by reducing the peak load by factor 2

Group with assumed energy consumption / base / peak		**Base load CHF**	**Peak load CHF**	**Savings in CHF and % of peak load**	
1	40 GWh / 10 / 20 MW	1’299’360	1’793’520	494’160	28 %
2	12 GWh / 3 / 6 MW	457’176	623’208	166’032	27 %
3	400 MWh / 100 / 200 kW	22’741	29’574	6’833	23 %
4	80 MWh / 20 / 40 kW	4’923	6’392	1’469	23 %

The example shows that the change of load curve can bring savings of approximately 25 % on the network tariff.

The group of household consumers is not included in the example .This group has in Switzerland no load measuring devices and only energy tariff, but mostly with two tariffs, night and day. Nevertheless the impact on the load curve shape is not to be disregarded. Figure 17 shows an example of the household demand curve and there is a significant high spread between maximum and minimum to be observed. This spread and the unpredictability of the peaks is today managed by using combined load profiles based on sophisticated models.

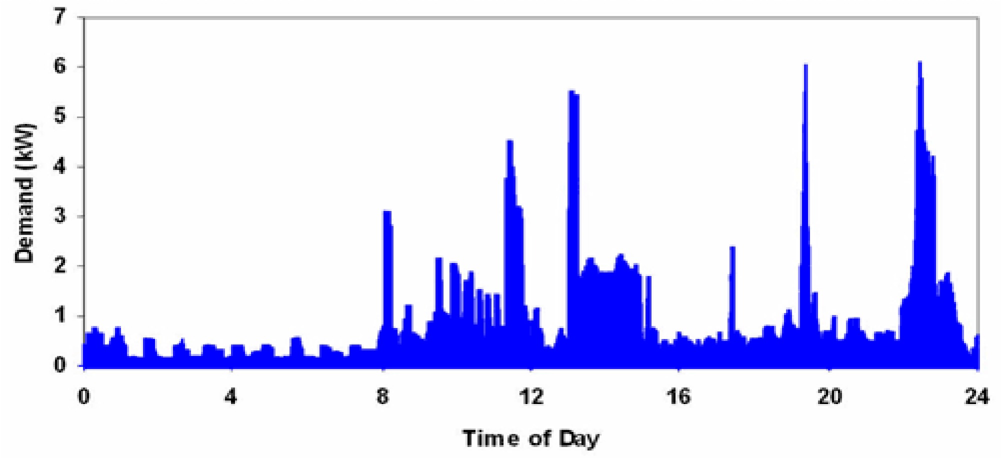

Figure 17, Individual household electricity demand
(source: http://www.mpoweruk.com/electricity_demand.htm)

3.3.2.2 Network losses

Network loss means basically cost for DSO. The losses are normally determined by comparing the in-feed and out-feed power measurements of each network operator. In Europe and North America, average network losses are around 7% and about 75% of the losses are situated within the distribution network[2]. For Switzerland, with a total consummation of 60.4 TWh in 2004 the total losses are approximately 4.3 TWh. An estimated distribution of the network losses to the network levels is shown in the following table.

Table 7, network losses on each network level in CH 2004 (Bauer, 2009) and own calculation.

Network level	Out – feed in TWh	Losses in TWh	Losses in % of the total loss
1	4.2 (without transit)	0.1	2
3	5.6	0.3	7
5	16.8	0.5	12
7	33.8	3.4	79

(Höckel M, 2003) made a simulation in a MV network (level 5) in Switzerland on the impact of network losses depending on different load conditions and production of DG within the network.

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[2] http://www.leonardo-energy.org/drupal/node/2935

Cases 1 and 2 are with planned load, case 3 and 4 with maximal load and case 5 and 6 with minimal load. The three load cases are analysed with zero DG generation and an estimated maximum DG generation. In case 2 the DG portion is 41.36% and in case 4 it is 46.07%. Both of this cases show a drastic reduction of the losses of approximately factor two. Due to the minimum load in the network is the DG portion in case 6 much higher, 138,56% with a high back-feed of power to the upper network level and a as a consequence losses which are 3.8 times higher than with zero DG production. Without going into further analysis the results show **that a DG production of around 50% could bring a reduction in losses of about factor two**. But it could have an opposite effect, which means increase of losses, if the percentage of DG production versus load is more than 100%.

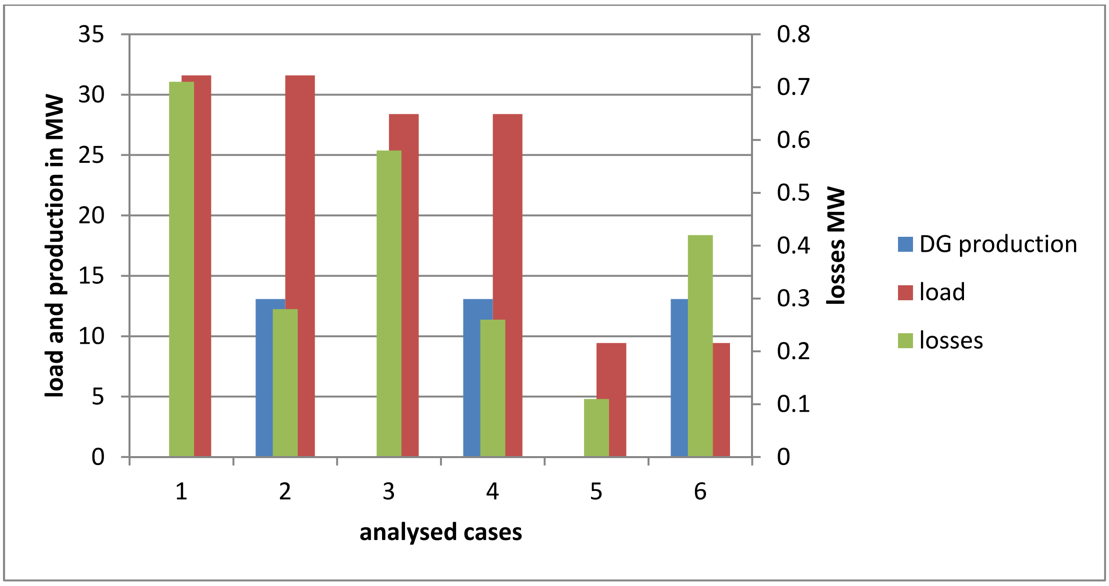

Figure 18, impact on losses by different load / DG proportions (Höckel M, 2003)

Considering the fact that DG production to load proportion of 50% and the fact that more than 70% of the losses are produced in the distribution network it is obvious that the location of DG near the load can lead to a massive reduction of the losses in a network area. The commercial impact could be analysed in detail by aggregating the cost of distribution network losses. To estimated the total cost of losses in Switzerland the losses from table 7 are multiplied with the average prices in Switzerland in 2011 including network and public charges and shown in table 8 for the network levels 5 and 7. The prices for network levels 3 and 1 are not public but considering that the losses on these network levels are only approximate 10% of the total network losses and the tariffs are much lower than on the levels 5 and 7 they can be neglected.

Table 8, price of electricity for Switzerland 2011 (Source: VSE Medienkonferenz 26.08.2010)

Network level	**Price in Rp / kWh (Energy & network- & public-charges**	**Cost in Mio CHF Price * losses**
5	16.4	82
7	22.3	758

The figures are not negligible and have a certain potential to increase the social welfare but will not be further used in this thesis except as an additional driver for the increased use of DG.

One of the best solutions to minimise losses in an electrical network is to operate the network in its optimal operating conditions. That means finally to control the load and production in each branch or node of the system based on its design criteria and this is basically the task of the grid control system.

3.3.2.3 Load shifting

As shown in the previous chapter the peak of a load curve has significant influence on tariffs for the consumer and on the network planning for the operator. In general the load can be influenced by planning and control. The classic approach was that the production followed the consummation and further influenced the decision of power plant investments. The system with balancing and scheduling with appropriate control facilities on the transmission level was traditionally sufficient for system stability and load/generation balance. On the distribution level the load control was done by ripple control. The following two principles are used to control the load up to a certain level.

a) Peak clipping

By this method certain devices (e.g. washing machines) were blocked during peak hours in order to reduce the peak load. The devices were certainly used in other periods but this was completely unknown and not predictable.

b) Valley filling

By this method loads were switched on, respectively were allowed to be switched on, during low demand periods (normally night hours between 24:00 and 06:00). Also here the actual load was not predictable since the demand for switching the load was not known.

In addition a two-tariff principle (lower tariffs for low demand period and higher prices during peak demand periods) should stimulate a load shifting. The switching between the two tariffs on the measuring device was also done by ripple control. In practice a lot of software programs have been developed to predict the loads and reduce the cost for imbalance of balancing groups. Together with peak clipping, valley filling and two tariff principle the system in many European countries was manageable without more sophisticated control principles. The system used today for this is the Ripple Control (RC) system and has a high level of standardisation and interoperability.

The control of loads is done on the higher network levels in order to use the capacities of the lower network level in efficient and safe manner. It is therefore still the “old” top down approach of the electricity network systems. And mainly based on standard load curves and fixed switching times. By this method loads were switched on, respectively were allowed to be switched on, during low demand periods (normally night hours between 24:00 and 06:00) and blocked during peak demand periods. With this technique a certain level of load shifting could be performed.

c) Load shifting

This method shifts the load from the peak to the valley and includes the two principles from above (clipping and filling).

This allows real load management but the old top down approach which is based on standard load curves and fixed switching times is not sufficient for the integration of unpredictable production coming from DG.

All this additional processes to handle the load, to maintain the stability and restore the system after emergency can be summarised in the so called ancillary services.

3.3.3 The ancillary service market

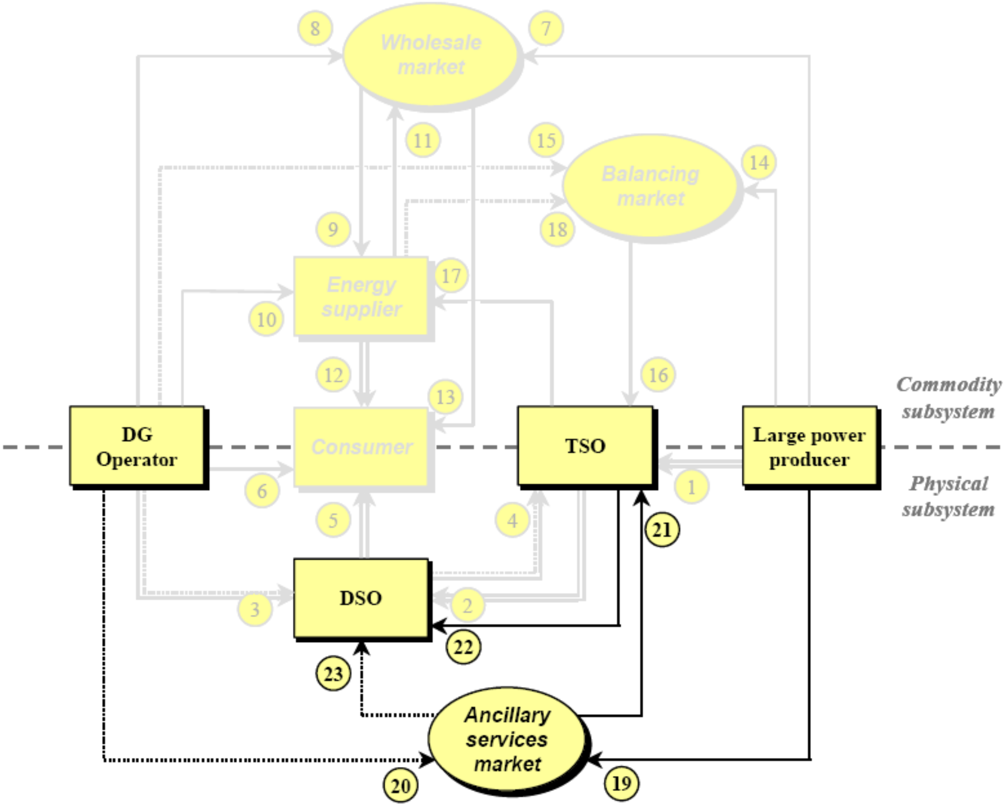

Figure 19, the ancillary market model, source: (Scheepers, 2005)

Ancillary services are in general all services necessary for the safe and secure operation of an electric system and include compensation for energy losses, frequency and voltage control, load shedding (flow control) for stability and precautions for restoration of supply. These services are provided by the generators shown in figure 19 by relation 19 and 20 and the electrical system operators (relation 21, 22 and 23) through an ancillary market. Today there is no common market place for ancillary services. Depending on the structure of the electrical network and the operators the services are mainly provided by the generators and DSOs connected directly to the transmission network. This does not mean that small DSOs do not need ancillary services like voltage support and compensation for grid losses. Some ancillary services can however also be provided by DG operators for DSOs and are indicated by relation 20 and 23. An overview of the possibilities of DG to provide ancillary services is given in table 17.

3.3.3.1 Operational availability of DG power

DG of small sizes are generally not centrally controlled and produce electricity based on either availability of resource (sun or wind) or heat demand in case of CHP. This is also influenced by the fact that the capability of controlling the electrical networks is today limited to the networks levels 1 to 4. Distribution network levels 5, 6 and 7 are traditionally not remotely controlled by a SCADA from a dispatch centre. The load curves have to be estimated and in addition to its hardly predictable hourly production curve they are not producing all year around. For Switzerland the following operating hours according (CONSENTEC, 2010) are estimated:

- Photovoltaic (PV)	1’100 hours
- Wind	1’250 hours
- Small Combined Heat and Power (CHP) units	3’750 hours
- Medium CHP units in industrial applications	up to 5’000 hours

The report (CONSENTEC, 2010) describes the economic efficiency of electrical networks with DG and use model networks for the calculations. To simulate the influence for DG they used a set of different types of DG’s based on the Study “Energieperspektiven 2035” from the federal office of energy in Switzerland. The chosen set of DG’s is representing a realistic development scenario for Switzerland and can be used as basis to calculate the operation hours of a set of DG’s connected to a typical electrical network. The quotient of produced energy and installed capacity is giving the total operation hours and will be used for further evaluation and the assessment for penetration of DG in chapter 5.

Table 9, calculation of operation hours based on model used in (CONSENTEC, 2010)

Network level	Installed capacity [GW]	Produced energy [TWh]	Operation hours
5	1.92	5.92	3’083
6	1.56	6.76	4’333
7	2.83	9.19	3’247

3.4 Change of dispatch and economics of centralised power plants of non-DG electricity producers.

Infrastructure of transmission networks is mainly based on large centralised power plants and also the market has developed according to existing electricity system.

Driven by concerns over climate changes the European Union has recently introduced the 20/20/20[3] targets which have led to strong support schemes to force the introduction of renewable generation.

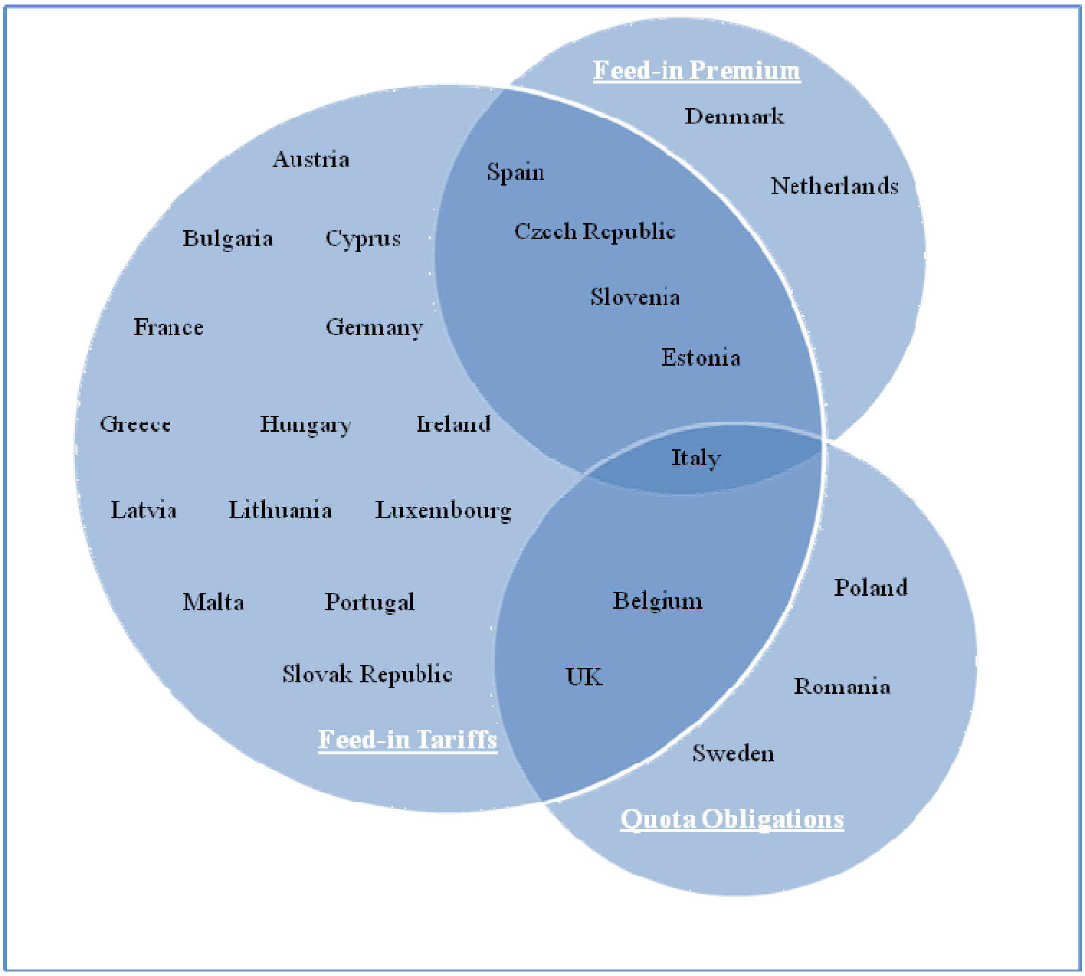

Figure 20, Overview of incentive schemes applied in EU, Source: CEER Report on impact of renewable support schemes

Theses support schemes are interfering with existing market functions since the production is paid with fixed tariffs and priority supply while revenue of conventional large producers is determined by the merit order. The support schemes now affect the merit order (low marginal costs) and as a consequence the wholesale price will tend to lower levels. The intermittent production from renewable resources will lead to higher price volatility. Large producers are therefore threatened with difficulties to recover the fixed-cost as they could be dispatched for fewer hours. This is leading to more difficulties reaching power purchase contract agreements for future

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[3] A reduction in greenhouse gas emissions of at least 20% below 1990 levels, 20% of EU energy consumption to come from renewable resources and a 20% reduction in primary energy use compared with projected levels, targets to be reached by the year 2020.

investments which is according to a KPMG[4] report a major precondition for banks to finance conventional power projects.

While DG electricity producers are mainly producing from renewable energy resources they benefit from incentive schemes introduced in European countries. Figure 20 shows the basic incentive schemes used actually in the EU. The business of the distribution system operator (DSO) on the other hand is based on regulated tariffs for the use of the network and services.

Increased penetration of DG on DSO level is changing the original business of the DSO. The simple distribution of electricity with a cost based tariff model is not suitable anymore. The increase of DG has several impacts on the threats of the DSO business but offers also challenges. The table below gives an overview based on findings in DISPOWER project (Scheepers, 2005)

Table 10, Threats and Challenges of DSO with DG

Threats	Challenges
Less energy transported over network – less income	Higher reliability in security of Supply – reserve capacity
Technical challenges and investments in the network – increasing costs	Reduction of system losses
Increase in inaccuracy scheduling – increasing cost	Active control of load/supply
Regulation schemes – price cap with benchmark efficiency hinder innovations and investments – costs not covered	Participate in ancillary services

3.4.1 Regulation schemes

In the European Union the unbundling of the electricity market is already in a quite matured stage and a strong regulation has been put in place. The regulation mainly focuses on the infrastructure based part of the electric system, the TSO and DSO. The regulation schemes have a certain period of validity which is up to 5 years (4 years in Austria, www.e-control.at and 5 years in UK, www.ofgem.gov.uk). The regulation schemes are based on investment- and operation cost of the network operator which defines the applicable charges for network use and connection.

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[4] KPMG, Power Sector Development in Europe – Lenders‘ Perspective 2011.

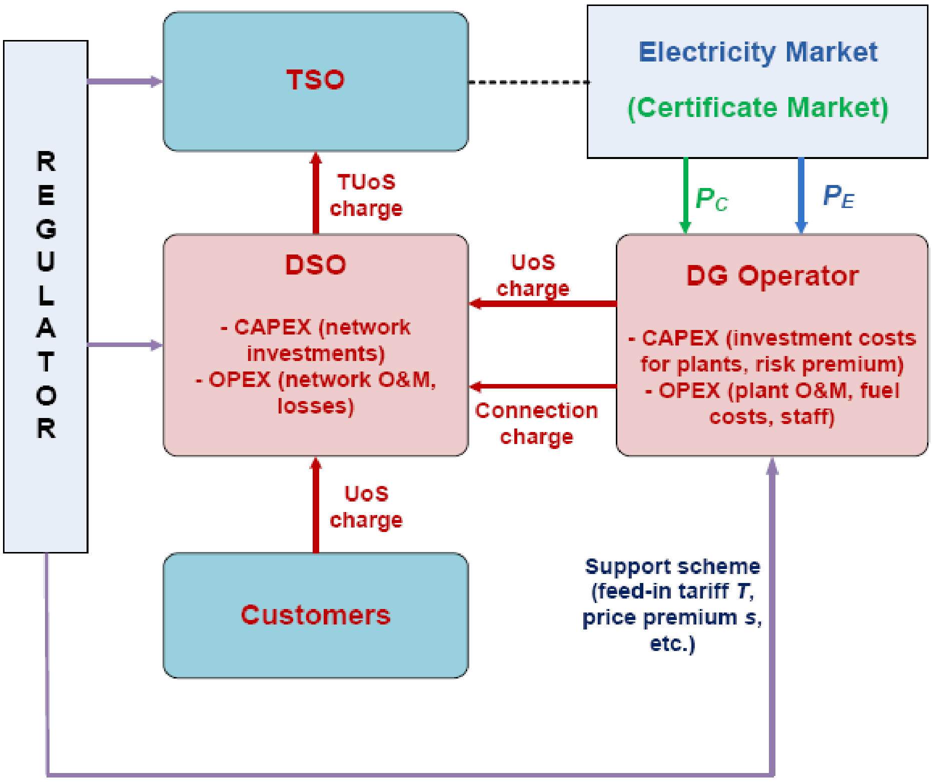

Figure 21, major regulatory interactions, source; (Nieuwenenhout, 2010)

Based on currently mostly applied regulation schemes there is no incentive for integration of DG on DSO level. The basic approach to calculate the tariffs is a function of Assets, WACC and operation cost.

$$TAR = f(RAB, WACC, OPEX)$$

- TAR: Total Allowable Revenue
- RAB: Regulated Asset Base
- WACC: Weighted Average Cost of Capital
- OPEX: Operation Expenditure

The use of a benchmark index for productivity or quality can be seen as a incentive for the DSO to invest in the network or operation processes (can also mean use of DG). The tariffs based on price cap calculation as above would be multiplied by a factor considering the inflation and productivity or quality index.

$$TAR_t = TAR_{t-1} \cdot (1 + CPI - X)$$

- CPI: Consumer Price Index
- X: determined by benchmarking

But to incentivise the DSO to use innovative solutions to install DG in his network the formula could be extended by two cost elements related to installed capacity and produced power by DG. The use of the factor for installed capacity is practiced in UK in specific registered power zones (RPZ) and shall demonstrate new and more cost effective connecting and operation principles for DG.

$$TAR_t = TAR_{t-1}(1 + CPI - X) + € A / kW_{DG} + € B / MWh_{DG}$$

Where A and B are specific costs caused by installed capacity and produced power.

Location differentiated incentive

As in the international electricity market locational price signals are a possible solution for security of supply. Nevertheless the long term investment security is not only given by such signals. By giving incentives the investment period and project period must be considered otherwise it is not leading to results.

Boundaries of DG connection to the grid

In practice the following cost sharing principles for DG grid connection are used:

- Deep integration

In this approach the DG investor bears several extra cost related to DG integration. This not only means the direct connection cost but also reinforcement cost within the existing network.

- Shallow integration

Under this principle the DG investor only bears the cost related to the connection of the facilities to the network. Reinforcement costs, if any, are socialised in the normal grid tariffs.

- Super – shallow integration

This is the best solution for the DG investor since the connection costs and the reinforcement costs are borne by the network provider and finally socialised in the grid tariffs.

4 Solutions to integrate DG

4.1 Smart grid

The main solutions for integrating more power production from renewable has been tackled in various R&D programs. The overall term "Smart Grid" has been defined under which all activities related to problems of integrating renewable production can be found. The Definition of smart grid is according to the position paper from 10. December 2009 from ERGEG as follows, " *Smart Grid is an electric network that can cost efficiently integrate the behaviour and actions of all users connected to it – generators, consumers and those that do both – in order to ensure economically efficient , sustainable power systems with low losses and high levels of quality and security of supply and safety".*

The understanding of smart grid is therefore not limited to decentralised production neither to the distribution grid. The following figure gives an overview of what is included in the smart grid deployment.

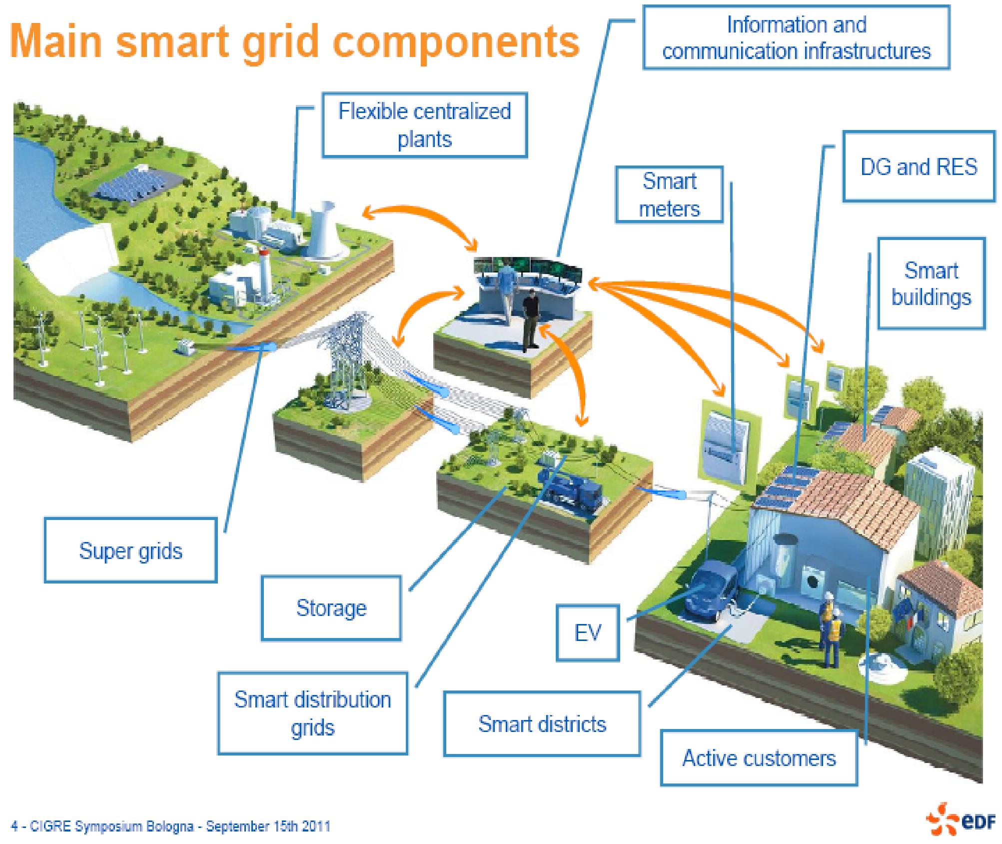

Figure 22, smart grid components (Source: EDF presentation, Cigré Syposium September 2011)

The Smart Grid deployment is a huge project and involves all the main manufacturers, TSOs, DSOs and Research institutions. As the focus in this paper is on small DG in distribution networks, only relevant and useful solutions, discussed under the smart grid umbrella for the integration of DG on DSO level, are selected. The selection of recently developed and public known solutions and proposals is not complete and there are certainly more solutions which are not listed here after.

4.1.1 Demand Side Management (DSM) also Demand Side Participation

DSM is the active participation of the customers in the scheduling of his electric energy demand by providing economical incentives. This means much more than a two tariff system (peak and off peak). The projects are leading to solutions where the customer receives real time prices and can react instantaneous. This approach is included in the smart grid idea and implies an open and liquid market in order to have accurate price signals given to the consumers. The Smart Meter (SM) is one of the devices which should facilitate the Demand Side Participation in future networks.

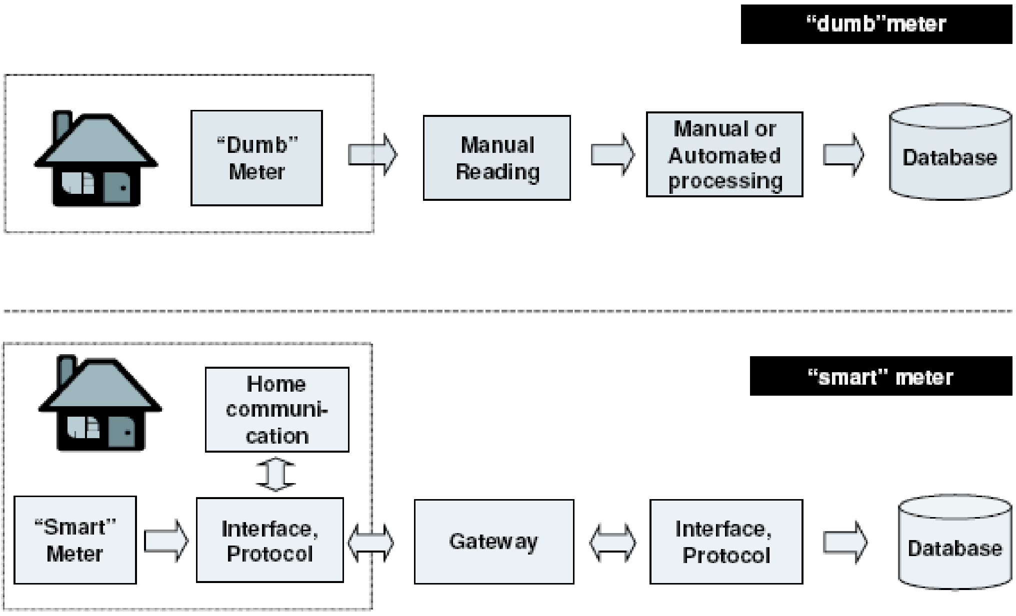

Figure 23, Smart Meter difference to conventional meter (Source: www.leonardo-energy.org)

The main advantage of the smart meter over the conventional meter is the ability of communication in both directions. This enables, depending on the communication technology used, a (near to) real time control functionality handled by a SCADA

System. That means information on price, load, voltage quality and more can be used by the consumer, the network operator and the energy supplier. The variety of involved parties and information available requires a strictly regulated data management with clear legislation and rules set up by the governmental bodies. Another point still open at the moment is the definition of technical standards to be used for smart metering applications. The European legislation requires an 80% roll-out of smart meters by 2020. Up to now there are different smart meter techniques and communication principles in use and especially the evolution of the cost will determine the winning technology to be used in the future.

Table 11, cost for load profile metering – smart metering

Unit / Task	Cost in CHF
Smart meter (Landis&Gyr)	300
Communication (Modem / GSM) (Landis&Gyr)	180 / 630
Data Services incl. Communication (www.ewo.ch, Obwalden)	900 / year

4.1.1.1 Lead time for Smart Metering / DSM / smart grid

The EU directives of the 3rd package 2009/72&73/EC, EU Member States have to ensure *“the implementation of intelligent metering systems that shall assist the active participation of consumers in the electricity/gas supply market. The implementation of those metering systems may be subject to an economic assessment of all the long-term costs and benefits to the market and the individual consumer or which form of intelligent metering is economically reasonable and cost-effective and which timeframe is feasible for their distribution.”* and directive 2006/32/EC on energy-use efficiency and energy services, *“final customers for electricity, natural gas, (…) are provided with competitively priced individual meters that accurately reflect the final customer's actual energy consumption and that provide information on actual time of use”*
The rollout for such devices, generally identified as smart meters must be planned as such that 80% of the consumers are equipped by 2020. The actual situation presents different stages of rollout and functionality levels. Table 12 shows the time scale for two projects in Switzerland on a small scale (pilot projects) and two large scale projects.

Table 12, lead time of smart meter projects

Project	Time scale	Time in months
Pilot project of Group E Deployment of infrastcure Deployment of process (products)	 1.10.10 – 31.12.11 30.6.11 -	 14 Expected 12
Pilot project Arbon Energie AG Deployment of Infrastructure Deployment of Process	 01.12.07 – 1.11.08 01.11.08 – 1.10.10	 11 11
Smart meter rollout in France www.erdfdistribution.fr	2013 - 2018	60
Rollout in Victoria Australia http://dpi.voc.gov.au/smart .meters	2009 - 2013	48

The pilot projects in Switzerland are involving only a part of the consumers and processes and are under continuous development as long as the regulation schemes, standardisation for hardware and data handling are not finally defined. Development of new regulation schemes and standardisations are time consuming processes and can last more than two years after final decision of implementation. Even though many pilot projects might be finished until 2012 there is still a long way to go. Considering that the duration of the pilot projects was already approximately 24 months the time scale for the project in France and Australia can be considered as a realistic reference which means a minimum of 48 months.

4.2 Storage

Another solution to support distributed generation is focussing on the storage of the energy. The use of large storage facilities is already a common practice to enable load shift on transmission network level. Today this is done by large hydro pump storage plants which operate mostly in conjunction with peak load power plants in mountainous areas by using the same upper and lower reservoirs. The storage in distribution networks has so far only be used on island networks with no or weak connection to the mainland and pilot projects. The principle of using small storage units together with DG is new and is another solution of load management. The locally produced energy by DG is locally consumed by the time needed. This principle helps to avoid network reinforcements and load management systems. There are different technologies of storage used and the selection is made depending on the energy shift demand, rated power output, discharge time and price.

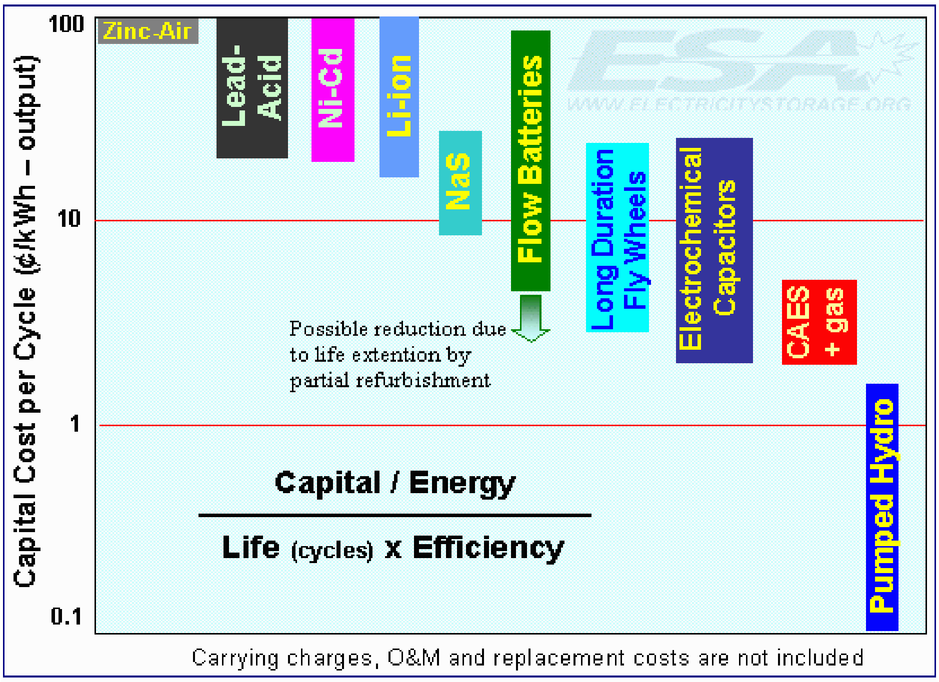

Figure 24, cycle cost of storage systems, source: www.electricitystorage.org

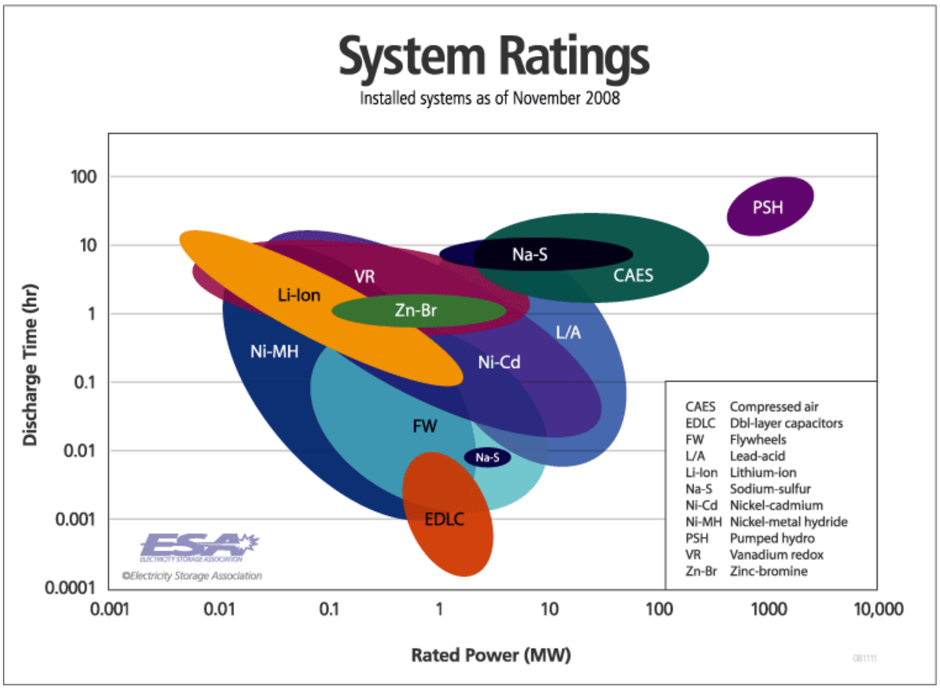

Figure 25, discharge time versus rated power of storage technologies (Source: www.electricitystorage.org)

The local storage of electric energy near DG production is actually not supported by regulation schemes. Today Storage systems are used for UPS (Uninterrupted Power Supply) applications. But discussions are ongoing and in the near future local storage could be a part of the solution to increase the proportion of small DG.

4.3 Solutions for the problems described in chapter 3

Different solutions are listed in the following four tables according to the problems described in chapter 3. The tables are grouped based on the main chapters 3.1 until 3.4 and summarizes the solutions. The List might not be complete but shows the solutions commonly known with public available documentation. The identification number in the first column is coded with the problem group (VQ = Voltage Quality) and a number and will be used as a reference in all tables in chapter 5.

4.3.1 Voltage and power quality (VQ)

Table 13, solutions for Voltage Quality

Identification No.	solution	example of projects and stage of implementation
VQ 1	Network reinforcement	Business as usual
VQ 2	Voltage regulation on medium voltage in-feed transformer with tap changer and communication between MS stations	DG DemoNetz (Brunner H, 2010), pilot projects and first networks equipped
VQ 3	P,Q regulation of DG	Static voltage support by reactive power support of DG. New guidelines for MV in force for LV planned.
VQ 4	Load / DG switch / Storage / DSM	Smart grid approach, pilot projects but no standards yet. New developments ongoing

4.3.2 Safety and protection (SP)

Table 14, solution for safety and protection

Identification No.	solution	example of projects and stage of implementation
SP 1	New circuit breaker (CB) with protection functionality	Business as usual
SP 2	New CB with protection and communication for intertrip	Equipment available but seldom used on MV
SP 3	Area wide communication and protection integrated in control	Smart grid approach, pilot projects but no standards yet. New developments ongoing

4.3.3 Grid control and stability (CS)

Table 15, solutions for grid control and stability

Identification No.	solution	example of projects and stage of implementation
CS 1	Balancing	New possibilities of pooling from 2012 (Swissgrid)
CS 2	Ancillary services	New business models necessary
CS 3	Area wide communication with load / generation control and storage / smart metering	Smart grid approach, pilot projects but no standards yet. New developments ongoing

4.3.4 Change of dispatch and economics (DE)

Table 16, solutions for change of dispatch and economics

Identification No.	solution	example of projects and stage of implementation
DE 1	Payment for capacity	Capacity schemes discussed (Cailliau, 2011)
DE 2	DG incentive for DSO (regulation scheme)	Ofgem, UK regulator introduced new model for DSO with incentive for DG (Registered Power Zones) see also (Currie & Ault, 2007)
DE 3	Active distribution grid	Smart grid approach, pilot projects but no standards yet. New developments ongoing

4.4 Opportunities for DG

4.4.1 Markets

Based on the market models shown in previous chapters (figures 1,12,19) there are potential opportunities for DG to participate in markets. However these markets are up to now not open for DG operators but some development can be expected. It can be assumed that these developments will go hand in hand with the increase of DG and it is difficult to estimate a time schedule (see also chapter 5.1).

4.4.2 Market for ancillary services (AS)

The AS are managed by the system operator in order to provide a safe, secure and reliable operation of his electric power system. Basically the provider of AS must be able to participate in active power reserves, load follow capacity, voltage capacity and reactive power supply, good performance in disturbed situations and contribute to restoration after an incident. As a consequence the following capabilities must be provided:

- Frequency control – active power
- Voltage control – active and reactive power
- Stability control – balancing – active power
- Load control – scheduling power flow - congestion management
- Restart of the system – black start – islanded operation

These services are today managed by the TSO and large power plants. The Swiss TSO Swissgrid, has defined the following AS:

- Balancing reserves (primary, secondary and tertiary)
- Voltage support
- Compensation of losses
- Black start and Islanded operation
- System coordination
- Measuring services

Table 17; Technological capabilities of DG Units to provide Ancillary services (Braun, 2007)

DG Unit / Ancillary services	WTG		PV (INV)	Hydro		CCHP				Storage		Load
						thermal-dirven		electricity-driven				
Frequency control		+	+		+		no		++		++	+
Voltage control, Congestion Management, Optimisation of Grid Losses	INV	++	++	INV	++	INV	+	INV	++	INV	++	+
	SG	++		SG	++	SG	+	SG	++	SG	++	
	DFIG	+										
	IG	-		IG	-	IG	no	IG	-	IG	-	
Improvement of Voltage Quality	INV	++	++	INV	++	INV	++	INV	++	INV	++	-
	SG	no		SG	no	SG	no	SG	no	SG	no	
	DFIG	+										
	IG	no		IG	no	IG	no	IG	no	IG	no	
Black Start	INV	+	+	INV	+	INV	no	INV	++	INV	++	no
	SG	+		SG	+	SG		SG	+	SG	+	
	DFIG	-										
	IG	no		IG	no	IG		IG	no	IG	no	
Islanded Operation	INV	+	+	INV	+	INV	no	INV	++	INV	++	no
	SG	+		SG	+	SG		SG	++	SG	++	
	DFIG	-										
	IG	no		IG	no	IG		IG	no	IG	no	
Fault-Ride-Through	INV	++	++	INV	++	INV	++	INV	++	INV	++	-
	SG	-		SG	-	SG	-	SG	-	SG	-	
	DFIG	+										
	IG	--		IG	--	IG	--	IG	--	IG	--	
Legend	Grid Coupling technology IG direct coupled induction generators SG direct coupled synchronous generators DFIG double feed induction generator INV Inverters					++ indicates very good capabilities + indicates god capabilities - indicates little capabilities -- indicates very little capabilities No indicates that this is not possible without additional external equipment						

Participating in AS services is today fully defined on TSO level. Some AS are also defined on DSO level like compensation of losses, system coordination and measuring services. More services might come in future with active distribution grids.

Table 18, ancillary services for a TSO today

Ancillary Service	description	provider
Balancing Primary	Direct control by TSO of turbine governor, reaction within milliseconds	Large power plants
Balancing Secondary	Direct control by TSO of turbine governor, reaction within seconds	Large power plants
Balancing Tertiary	Dispatch by the TSO within 15 minutes	Large power plants and balancing groups
Voltage control	Reactive power	Power plants and balancing groups
Compensation of losses	Only for TSO grid losses	any energy supp supplier
Black start and Islanding	Power system restoration after incident	Power plants connected to the TSO network
System coordination	Dispatching, congestion management of TSO network	Network operator
Measuring services	Providing Measuring and data transfer services	Owner of electric network

4.4.2.1 Expected Revenues for ancillary services

The Energy Research Centre of the Netherlands presented some figures on revenues for ancillary services (Scheepers M, 2005) based on an ECN Policy Study. Three principles of fees are known:

- Flat (irrespective of running status and quantity)
- Option (based on availability)
- Exercise (based on supply)

Table 19, estimated revenues for ancillary services, source: (Scheepers M, 2005)

service	Value / year in Euro
Frequency	3.72 / kW for CCGT
Reserve	10.4 / kW
Voltage & Flow control	2.23 / kW
Services (black start and Islandic)	2.08 / kW residential 28.23 / kW commercial
Security of supply	1.49 – 17.83 / kW

4.4.3 Balancing market in Switzerland

Primary reserve is provided by power plants connected to the transmission grid and purchased in weekly portions of ±1 MW. The supplied energy is not reimbursed, only the reserve power. The costs of the secondary and tertiary balancing services are depending on the market. It is in the interest of the society that costs for balancing are minimised. But from the point of view of the producer, balancing is a business. The following table shows the demand of balance power for Switzerland.

Table 20, volumes of balancing services in Switzerland 2011, source: Swissgrid

Balancing service	volume	Power	Energy
Primary PRL	±77 MW	Merit order purchase	Not remunerated
Secondary SRL	±400 MW	Merit order purchase	Hourly spot price ±20%
Tertiäry TRL	+510 MW -460 MW	Merit order purchase	Merit order purchase

The prices are not all public but some prices for the balancing power are shown in figure 26. We can see that tertiary power (TRL) is quite cheap while primary and secondary is valuable. A participation of DG in the balancing market could be possible by grouping DGs in portions of 1 MW. A balancing market on DSO level might also be possible since DSO participate in balancing groups and unbalance payments may also create market opportunities.

4.4.3.1 Actual prices for balancing power in Switzerland

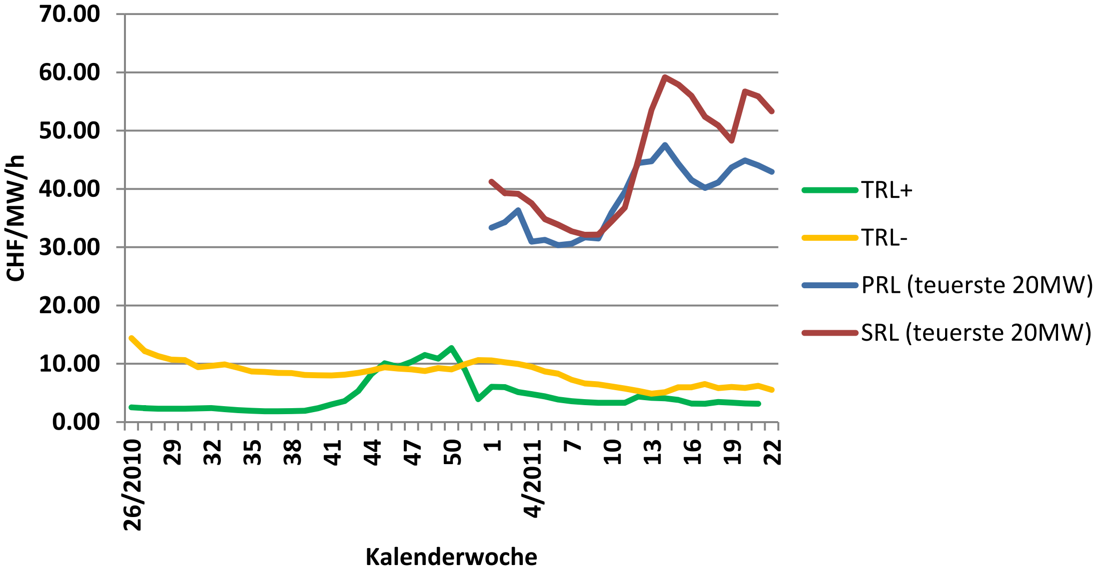

Figure 26, prices for balancing power in Switzerland, source: www.swissgrid.ch

According to (CONSENTEC, 2010) would the increase of DG of 6’590 MW installed capacity in the Switzerland cause an increase of balance capacity of 60% and balance energy of 68 %. Based on market prices of 2010 this would lead to an increase of network tariff of 0.35 Rp/kWh.

4.4.4 Opportunities

The solutions for the problems in chapter 4.3 open also opportunities. Especially new markets for balancing and ancillary services would provide economical opportunities. In addition all that is related to the smart grid approach. The following table shows in short the problems respectively opportunities.

Table 21, main opportunities for DG

Identification No.	solution	example of projects and stage of implementation
CS 1	Balancing	New possibilities of pooling from 2012 (Swissgrid)
CS 2	Ancillary services	New business models necessary
VQ 4, SP3, CS 3, DE 3	Active distribution grid	Smart grid approach

5 The approach to assess the prospects of DG

5.1 System description

To approach this question the system has to be defined. A mainly technical based system is determined by components which interact in processes with each other and can be seen as a coherent object. It interacts with its environment in both directions. That means it can be influenced (controlled) and reacts with a specific output. A car or a power plant can be seen as technical system with clear purpose and interaction with its environment. The question now is, is an electricity network with producers and consumers a simple technical system?

In the past the producers had their own electrical network and were building a system supplying the customers based on a clear demand request. The system "electricity supplier" managed the production and distribution within its system borders could be seen from outside as a system supplying electricity. Mostly this was combined with a monopoly because there was no free market for the commodity electricity. So the answer would be more or less YES.

5.1.1 System discussion

The market component (or subsystem as shown in figure 1) brings now a social influenced component into the system. A division in interacting subsystems like network, power plants and markets is maybe too simple and the management model, developed at the University of St. Gallen is giving some indications how to look at the electrical system with the help of a modern management and organisation tool. In conjunction with this model Knut Bleicher has developed a system model which can be used here to show the processes and bodies involved in the system "electricity business". On the horizontal path are the steps to reach the goal, the development path. These steps are embedded in necessary structures, activities and attitudes. On the vertical path are the main bodies relevant for the role in a development process. The roles are grouped in normative, strategic and operative, from top down towards the steps and activities on the development path. The next figure shows the model based on the structure according K. Bleicher with specific tasks on the development path towards higher penetration of DG. On the upper half where the normative tasks are located the main bodies involved are the government, the regulator and the administration. They define the market rules and boundaries of the playground (incl. transparency and supervision of the market). On the lower half the utilities are located which act according to the rules of market and technical standards and codes. The bisection of the system "electrical supply" can be used to assess the influence on time delay.

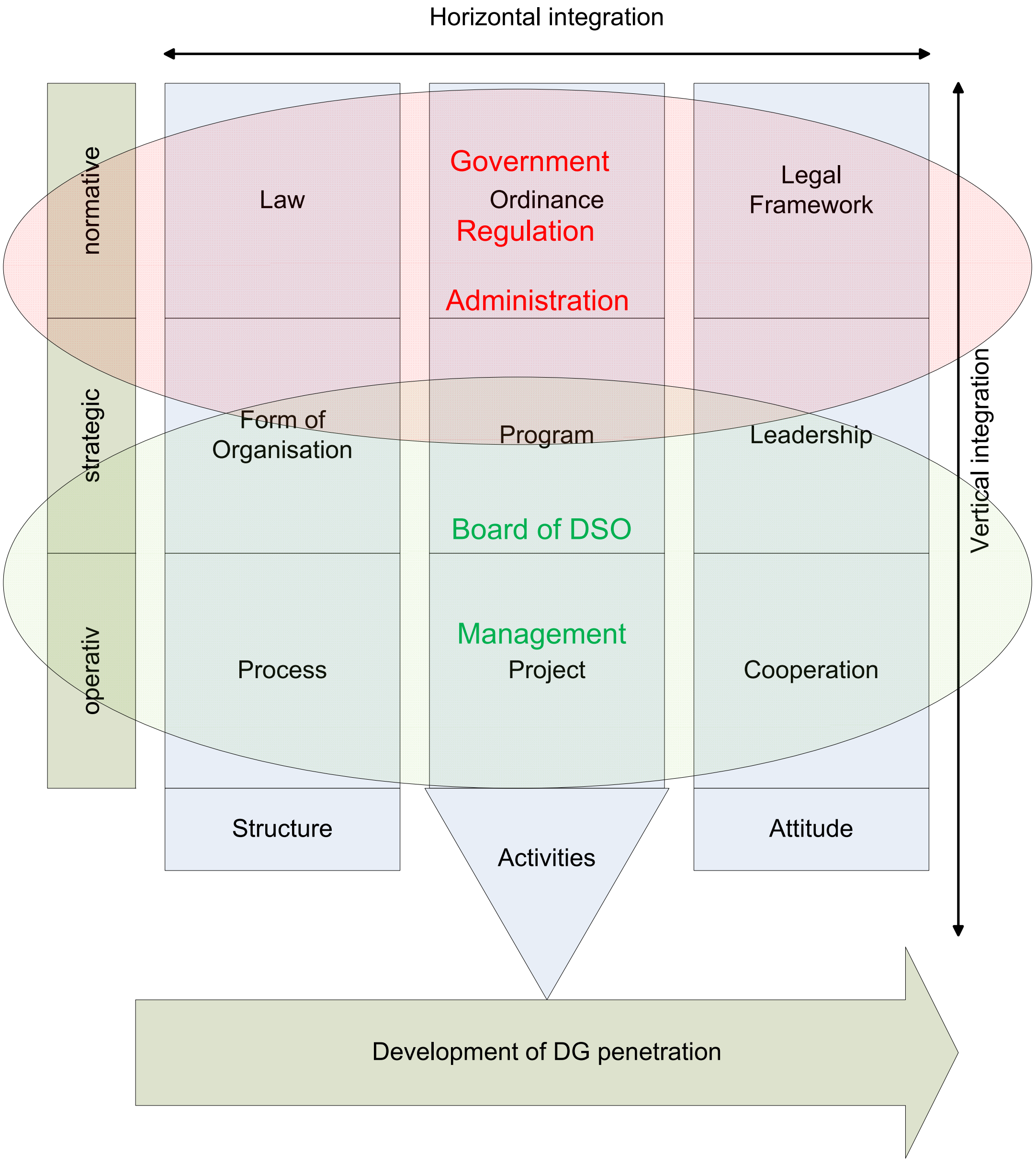

Figure 27, involved bodies in the electrical business

5.1.2 Time periods for structural changes of the system “electricity supply”

The decisions in the European Union towards a sustainable Energy supply have been made in 2007 with the 20/20/20[5] plan. And the open market has recently been defined by the 3rd Energy Package which is in force since 2011. This means that the red area in the model of the electrical business in figure 27 has already set up the rules. The work has to be done by the administration now and the European Commission (EC) has set the target for full market integration by 2014. The European Agency for Cooperation of Regulators (ACER) will support the regulators on inter-regional key projects, defined to facilitate the full market opening. The four key projects are:

- Single European Price Coupling
- Implicit continuous Cross-Border Intraday Trading
- Single European Platform for Long-Term Transmission Rights
- Flow-based Market Coupling in highly meshed networks

For detail please refer to: http://www.acer.europa.eu/

The legal framework is therefore defined and no time delay for integrating DG in the EU has to be expected from the normative level. The situation in Switzerland however is different and the actual electricity act is going to be revised. The planning is not secured yet since the energy strategy must be revised first, which is planned to be discussed during 2012. With a legislation revision period of approximately 4 years we have to expect some time delay in the red upper area of the model in figure 27. The influence in the lead time is strong even in the EU administration processes are not fast. **In the normative area with change in law, ordinance and regulation, and for strategic decisions up to 4 years and more must be considered**. Regulation periods as well have durations of up to 5 years (see chapter 3.4). At the lower part of the system, with operative tasks and strategic decisions in the hand of individual DSOs, the time path can be shorter depending on the attitude of the company. Many pilot projects have been initiated already on this level. A development path with shorter lead time that uses technologies and / or business cases could be located in the green, lower area of the system graph. To use ripple control for improving DG concentration in a network would be exactly in

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[5] A reduction in greenhouse gas emissions of at least 20% below 1990 levels, 20% of EU energy consumption to come from renewable resources and a 20% reduction in primary energy use compared with projected levels, targets to be reached by the year 2020

this area since the systems are individual located and managed by the DSOs. Each DSO can therefore take decisions how to use this system without waiting on strategic and normative developments looking further up at the vertical integration path. **Changes in this section of the system could be done within one business year by assuming that problems within a DSO can be solved shortly after small changes in the business processes**.

5.1.3 Time periods for investments in DSO (depreciation periods)

In order to minimise the cost each DSO plans to use the existing assets until its life time. The expected life time of the equipment in Switzerland is listed in table 22 and shall be the business as usual case. This means that necessary equipment which has a long depreciation period gets a significant worse benchmark than equipment with a short depreciation period.

Table 22, depreciation period of network components, source: VSE NNMV-CH, 2008, Netznutzungsmodell für das Schweizerische Verteilnetz

Network component	Depreciation period in years
Cable MV / LV	35-40
Overhead Line MV / LV (wooden pole)	20-25
Overhead line MV (steel or concrete)	35-40
Control Cable	20-25
HV / MV Transformer	30-35
HV / MV switchgear	30-35
HV / MV C&P, measuring	10-15
MS / NS Transformer	30-35
MS / NS Pole mounted transformer	25-30
MS / NS switchgear	25-35
MS / NS C&P, measuring	10-15
IT HW and SW (management process)	03-05

5.2 Procedure of assessment

The electrical networks are in general not exactly comparable in size, physical form and operation because of the historical development, geographical conditions and evolution processes. Even though the technical standards are the same within

Europe evaluating quantitative figures would be very time-consuming. Using the results in the previous chapters as qualitative measures for an assessment is here considered as appropriate. The benchmark is the actual standard solution of integrating DG, the network reinforcement. Together with problems arising due to old top down structure of the network use it is declared as "business as usual".
To evaluate the possible increase of DG quota in a network by using ripple control the DG integration without any control and stochastic production is the business as usual and used as benchmark.

The assessment will be done in 3 parts:

a) Problems and opportunities based on business as usual
b) Possible level of DG integration based on business as usual
c) Impact in a) and b) by using ripple control

The detail assessment in part a) is done in two steps. In a first step the indicative values found in the chapters 3 and 4 are used as qualitative information towards the benchmark "business as usual". The qualitative information is divided in 5 steps for cost and revenues together with information about lead time.
The general approach is as follows:

considerably better	better	business as usual	worse	significantly worse
++	**+**	**0**	**-**	**--**

The same structure and identification numbers as for the solutions in chapter 4.3 and the opportunities in chapter 4.4 will be used. The results will be shown in a matrix analogue to the BCG.Matrix[6] used for portfolio analysis, showing the potential versus lead time.

High potential / long lead time	High potential / short lead time
Low potential / long lead time	Low potential / short lead time

To evaluate the lead time the estimated time for system changes and depreciation periods of network assets as shown in the previous chapter are used.

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[6] http://de.wikipedia.org/wiki/BCG-Matrix

The assessment in part b) is done by using indications on DG quota and impact on cost and operation problems which are mainly based on stochastic production and load management. The indicators are grouped in three categories:

- No impact
- Impact to be expected
- Heavy impact to be expected

And the results are shown in a table with impact versus DG quota / max. Load.

5.3 Problems and opportunities based on business as usual

First step assessment for problems related to investments referenced to identification numbers as per identified problems in chapter 4.3.

Table 23, analyse of problems related to investments

Id.No.	**description**	**Cost**	**time**
VQ 1	Network reinforcement	**0**	**0**
VQ 2	Voltage regulation on MV/LV transformers	**+**	**-**
VQ 3	P, Q regulation of DG	**+**	**-**
VQ 4	Load / DG switch / storage / DSM (smart grid)	**-**	**--**
SP 1	New circuit breaker (CB) with protection	**0**	**0**
SP 2	New CB with protection and communication	**-**	**-**
SP 3	Area wide communication / protection via control	**-**	**--**
CS 1	Balancing (more balancing necessary due to DG)	**-**	**+**
CS 2	Ancillary services (more ancillary services)	**-**	**+**
CS 3	Area wide control with DSM and storage	**-**	**--**
DE 1	Capacity payment (investment incentive)	**-**	**-**
DE 2	DG incentive for DSO	**+**	**-**
DE 3	Active distribution grid	**-**	**--**

Qualitative assessment parameters:

Cost compared to DSO without DG (as today)

++	considerably less cost to be expected
+	less cost to be expected
0	neutral

-	more cost to be expected
--	significantly more cost to be expected

Time

++	possible with already installed equipment
+	short investment cycle, replacement in due time
0	new standard equipment necessary
-	medium investment cycle or new application to be developed
--	long investment cycle or new standards with new developments necessary

The second table shows the first step assessment for opportunities related to operation revenues referenced to identification numbers as per identified opportunities in chapter 4.4.

Table 24, assessment of opportunities of operation revenues

Id.No.	**description**	**Revenue**	**time**
CS 1	Balancing (participate in balancing market)	**+**	**0**
CS 2	Ancillary services (participate in ancillary market)	**+**	**0**
DE 3	Active distribution grid (with incentive regulation)	**+**	**--**

Qualitative assessment parameters:

Revenues[7]

++	considerably revenues to be expected
+	some revenues to be expected
0	neutral
-	some more costs to be expected
--	significant costs to be expected

Time

++	immediately applicable
+	shortly after small changes applicable
0	applicable to the next business year
-	change of contracts, business model and /or legal ordinance necessary
--	major change of law, regulation scheme necessary

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[7] Revenues in the regulation schemes as today is cost plus benchmark regulation for DSOs in the near future is considered.

5.3.1 Summary of results of assessment regarding opportunities and cost with business as usual

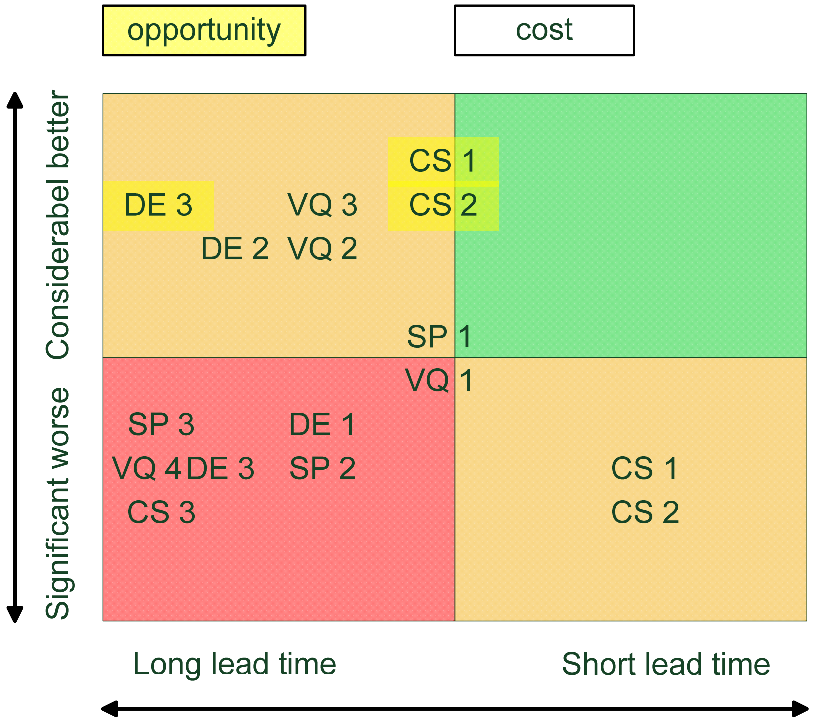

Figure 28, Matrix with problems / opportunities business as usual

The results shown in the matrix don’t look very promising. There are better solutions to conventional network reinforcement with replacement of switching devices but with longer lead time. The opportunities in markets like balancing and ancillary services would compensate the cost but needs some evolution and are not yet applicable.

5.4 Possible level of DG integration based on business as usual

An electrical network is designed by its maximal connections, the peak load and the average energy load. Considering the peak load to each connection more than 15 kW (with standard 25 Ampere nominal design value) doesn’t mean that every household is using this load at the same time (see chapter 2.2 load management). If we consider a simultaneity factor between 0.06 and 0.2 (Kaufmann, 1995) we end up with the dimensioning capacity of the network assets considering between 1 and 3 kW per connection. If we would now install area wide DG capacity without any control we can estimate that the capacity of the DG would be in the same range as the estimated simultaneous load.

The following tables show some results of studies showing possible DG capacities without control and network reinforcements.

Table 25, possible DG power to connect to household, source: (Scheffler J, 2002)

Network type	**Number of units (1 per households + one per farm)**	**Maximal possible DG power per household in kW** (MV ±3%)	**Transformer power kVA**	**Expected peak load kW / average consummation in kWH**
Detached housing area (high density) Fall D	176	2.83	630	176 * 2 / 7500[8] 1 * 2 / 17'520[9] 1* 15 / 30'000[10]
Village (low density and farms) Fall B	83+9 = 92	3.1	250	83 * 2.5 / 7500 9 * 5 / 8000[11] 1 * 5 / 15'000[12] 1 * 3 / 8000

Table 26, possible DG power to connect to households, source: (Degner, 2010)

Network type	**Number of units**	**Maximal possible DG power total / per household in kW** (LV +3%)	**Transformer power kVA**	**Expected peak load kW / average consummation in kWH**
Synthetic network	144	324 / 2.25	630	144 * 2 / 7500

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[8] Average consumption of 5 room house with electrical cooking, warm water heating and tumbler, CH-consumer class H5

[9] Telecom equipment, 8760 h/a load

[10] Average consummation of small company with max 15kW peak, CH-consumer class C2

[11] Average consummation off arm, CH-consumer class C1

[12] Street light, 3000h/a (estimation)

Table 27, possible DG power to connect to households, source: (Kerber, 2009), (Witzmann R, 2010)

Network type	**Number of units**	**Maximal possible DG power total / per household in kW (LV +2%)**	**Transformer power kVA / connection (expected)**	**Expected peak load kW / average consummation in kWH**
Detached housing area (urban)	*202 (= X)*	3.1	2.5 *$X^{\%}$ = (630*0.8)/2.5*	*X * 2 / 7500*
Village, low density with some farms	*80 (= X)*	4.6	4 *$X^{\%}$=(400*0.8)/4*	*X * 3 / 7500*
Countryside, farms and some houses	*22 (= X)*	8.3	9 *$X^{\%}$=(250*0.8)/9*	*X * 8 / 8000*

(cursive – own estimation and $X^{\%}$ calculated with 80% transformer load)

The studies defined 3 standard types of networks, detached houses with high density of households, villages with low density of households and some farms and countryside with farms and some houses. The next three tables are showing the results from above summaries of maximal DG power, total load and energy consumption per network type. With the estimated production hours for DG (= 3'247 hours from table 9), the estimated energy production of DG is calculated.

Table 28, average DG power in network type "detached houses, high density"

	Max. DG / house [kW]	**Load [kW]**	**Energy [MWh]**	**Peak production [kW]**	**% of Load**	**Production by DG* [MWh]**	**% of Energy consumed**
Table 25	2.83	369	1'368	498	135	1'617	118
Table 26	2.25	288	1'080	324	113	1'052	97
Table 27	3.1	404	1'515	626	155	2'033	134
Average	2.73	354	1'321	483	136	1'569[13]	119

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[13] 177 units

Table 29, average DG power in network type "village, low density"

	Max. DG / house [kW]	Load [kW]	Energy [MWh]	Peak production [kW]	% of load	Production by DG* [MWh]	% of Energy consumed
Table 25	3.1	261	718	285	109	926	129
Table 26	No values						
Table 27	4.6	240	600	368	153	1’195	199
Average	3.85	251	659	327	130	1’063[14]	161

Table 30, max. DG power to network type "countryside"

	Max. DG / house [kW]	Load [kW]	Energy [MWh]	Peak production	% of load	Production by DG*	% of Energy consumed
Table 25	No values						
Table 26	No values						
Table 27	8.3	176	176	183	104	593[15]	337

It can be seen that in all the studies the local energy consumption could be produced by the DG to 100 % and more and that also the load could be supplied. But here we have to consider the simultaneity and while the DG of the same type (PV, wind, heat controlled CHP) are supplying simultaneously, the demand curve probably has a complete different time behaviour and there will be still some peak load not covered by DG or vice versa some production to be feed back in upper network levels while not needed. An evaluation of this effect is given in next chapter

5.4.1 Time necessary for DG integration

Based on a simple project time planning the minimum time is estimated to install DGs of sizes according to above results by a sequential approach and starting from scratch. This means after the first project the following projects started in parallel and the limiting factor is the specific engineering, application procedure and commissioning. The manufacturing time is not limiting the sequential increase considering a large variety of suppliers. The total project time depends on engineering, application, approval, manufacturing, installation and commissioning.

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[14] 85 units
[15] 22 units

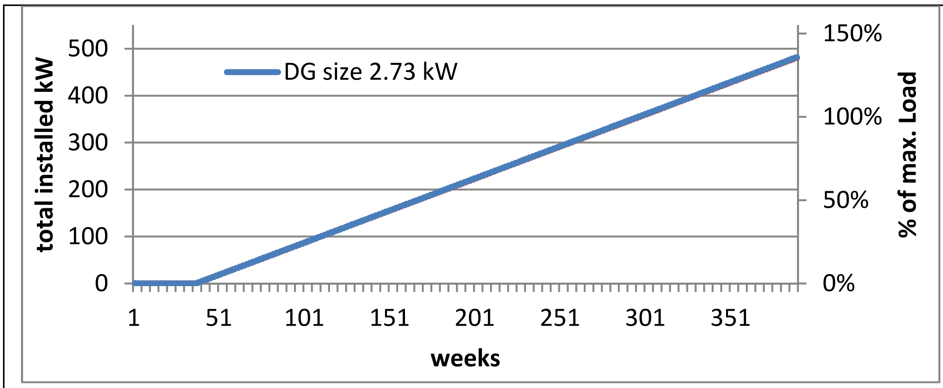
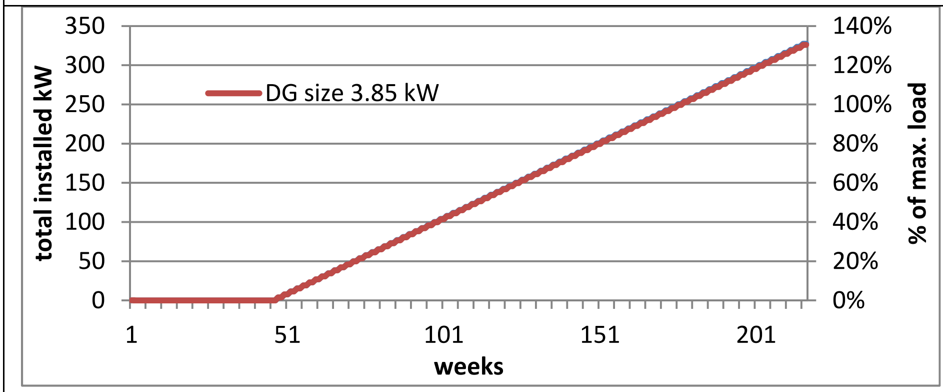
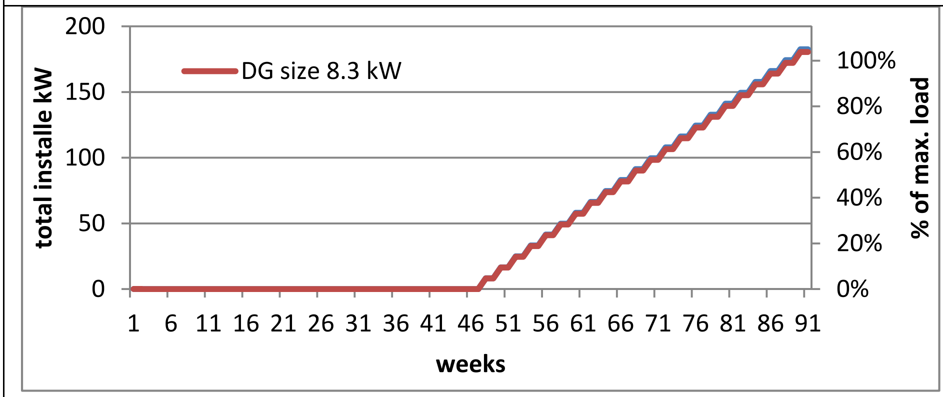
	Detached houses, high density 100 % can be reached in 6 years
	Village, low density 100% in 3.5 years
	Country side 100% in 1.75 years

Figure 29, time in weeks for DG installations in the 3 network types

5.4.2 DG penetration and effect on load curve.

The increased penetration of unpredictable DG has an impact on grid stability and control (see chapter 3). An indicator for this is the estimated demand of balancing power. To estimate the influence of DG penetration on balancing power increase a study by (CONSENTEC, 2010) determined the requirements of balancing power and capacity depending on the probability of the production forecast and the amount of installed DG. For the valuation only the forecast error of heat controlled CHP, PV and wind based DG is considered. The forecasting error for such production facilities is according to (CONSENTEC, 2010) ≥ 7%. With a DG production of 4’500

MW with a 7% forecast error the additional balancing capacity for Switzerland is 400 MW and with 3% forecast error it is 60 MW. The total installed electricity production capacity in Switzerland is 11'560 MW[16] in 2010 and the balancing power demand is 1'000 MW. This means that with a DG penetration of 39% with a forecast error in production of 7% we can expect an additional demand of 40% of balancing capacity. With 3% forecast error, meaning controlled DG production, the capacity in balancing power is only 6% more instead of 40%.

Another indicator is the spread of the load curve (difference of maximum to minimum load) and the possibility to minimise the peak load. In other words it is the capability to manage the load by shaping the load curve based on needs of the network operator in cooperation with the energy supplier. A research project for the State Niedersachsen in Germany (Pielke et al, 2008) shows an evaluation of the impact of CHP which are heat controlled compared to network controlled. Network controlled means, production based on demand defined by network operator and/or energy supplier. The influence of DG penetration according to this study is summarised in the two tables below. The first table (31) shows the impact on peak load reduction and load spread with heat controlled and the second table with network controlled DG.

Table 31, influence of heat controlled CHP on load curve, source: (Pielke et al, 2008)

Heat controlled	Degree of penetration		
	10%	20%	40%
Peak load reduction	7%	8.4%	11.9%
Spread reduction	0.1%	- 10.7%	- 23.3%
Back feed*	0 kWh	0 kWh	4912 kWh

*In upper network levels

Table 32, influence of network controlled CHP on load curve, source: (Pielke et al, 2008)

Network controlled	Degree of penetration		
	10%	20%	40%
Peak load reduction	7%	17.4%	29.3%
Spread reduction	0.2%	0.2%	- 2.25%
Back feed*	0 kWh	0 kWh	5263 kWh

*In upper network levels

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[16] Schweizerische Elektrizitätsstatisik 2010, BFE

The results show a clear trend of an advantage for network controlled CHP. The peak load can be reduced and therefore all the problems related to this (losses, network reinforcement, protection) there the load spread is almost the same as without DG. With heat controlled CHP the peak load can also be reduced but on much lower level while the load spread will increase and is acting more in the direction to boost the problems than solving any. **The conclusion here is that if a DG penetration is greater than 10% there should be a network controlled functionality foreseen.**

5.4.3 Summary of results of DG integration and impact on grid control and stability by business a usual

We have seen in chapter 5.3.1 above that in some network types a 100% DG production based on business as usual, which means simple network reinforcement, is reachable within a period of less than 2 years. By this period the smart grid solutions are not yet available (see chapter 4) and there is an impact by missing load management to be expected. The impact is measured in three steps and can include higher cost and / or lower security of supply:

🟩	- No impact
🟧	- Impact to be expected
🟥	- Heavy impact to be expected

The indicators are:

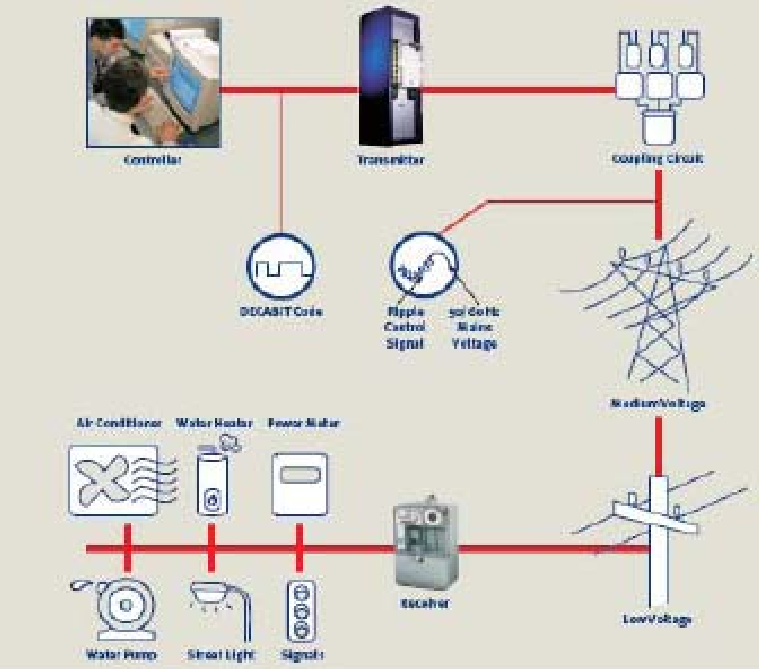
- Network losses optimum with 50% DG (see chapter 3)
- Balancing impact already with 40% (see above)
- Increase of load curve spread above 20% (see above) and therefore impact on increased cost for peak load (see chapter 3)

Table 33, summary of impact of DG / max. load with business as usual

Impact	🟩	🟧	🟥	🟥	🟥
DG / max. load	25%	50%	75%	100%	125%

6 Optimisation potential by using ripple control systems

6.1 Basic functions of ripple control



Basic function modules:

- Controller
- Transmitter
- Coupling circuit
- Electricity network
- Receiver
- controllable appliances

Figure 30, basic functions of ripple control system

Ripple control is used in many countries mainly to switch between tariffs and to control domestic load like room and boiler heating. The technology is proven, easy to handle and used on DSO level. This means, that DSO personal is trained to maintain and operate such systems. The principle is based on a frequency signal coupled into the 50Hz network. The frequency range of the signal is between 110 Hz and 1600 Hz[17]. The signals are generated in the transmitter defined by the controller. They can be based on time programs or event driven. The coupler is made of passive elements like capacitors and coils with isolating transformers. The electrical network distributes the signal to any receiver connected to the network. The receiver is decoding the signals and carries out the commands by switching the appliances' like heating's, boilers, pumps, street lights or activates tariff switching in

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[17] http://www.rundsteuerung.de/html/frequenzen.html

measuring devices. The reaction time is form 1 to several seconds and there are possibilities to switch individual channels or groups of channels.

Typical applications for load control with ripple control are:

- Blocking of heaters, heat pumps, washing machines etc. during fixed hours
- Switching between 2 tariffs in meters

New applications:

- Switching on and off of DG
- Switching between 4 tariffs, blocking appliances depending on load curve

The increased number of DG in a local network and a central dispatch via ripple control allows the DSO to participate actively in a balancing group. He can offer negative as well as positive power and reserve capacity.

One bottleneck of using ripple control might be the low performance in terms of time critical applications. In contrary it has to be considered that house hold appliances cannot be switched on and off in short intervals. That means once switched on they have to operate stable for a minimum time and vice versa if they are switched off. In addition some parameters like boiler loading respectively discharge and maximum stand still periods have to be considered as well. On the other hand the scheduling process is in steps of 15 minutes and trading of energy is in minimum blocks of one hour. The data rate for conventional ripple tasks is about 1 bit per second (1 Baud) and can be increased with modern byte coding systems up to approximately 50 Baud (Troller, 2011). But depending on the size of switchable groups it is even possible with the old standard protocols (Decabit, Semagyr) to complete control loops in a network within a ¼ hourly scheduling process.

6.2 Possible improvement of solutions (as per 4.3)

Table 34, Improvements by using ripple control

Technology, problem area and Id. No.	**Possible solutions**	**Similar technology but not ready yet**
DSM VQ 4, CS 3, DE 4	Price signal given to consumer (e.g. 4 tariffs with 2 control signals; Kamstrup Tarifsteuermodul)	Smart meter approach
Voltage control, VQ 2	Switching tap changers, capacitor banks, Q-setpoints, etc.)	Smart grid
switching between operation as load or generation. CS 3, DE 3	DG with local storage Especially for PV solutions, CHP can solve the problem of storage with heat storage.	Smart grid, (storage available but not used yet)
Reducing losses CS 2	Activating DG depending on network load	
Better efficiency of network CS 2, DE 2,	Increased power consumption with little investment and almost no network reinforcement. System support services.	Active distribution grid
Network operation under extraordinary conditions CS 2,	Rescue programm and restoration of network by	Active distribution grid
Balancing cost not increased due to DG CS 1	DG load switch according demand curve	Smart meter approach

With the possible solution from the above table the quantitative assessment under chapter 5.2 is repeated with new validation for problems and opportunities.

Table 35, assesment of problems (investments) with ripple control

Id.No.	**description**	**Cost**	**time**
VQ 1	Network reinforcement	**0**	**0**
VQ 2	Voltage regulation on MV/LV transformers	**+**	**+**
VQ 3	P, Q regulation of DG	**+**	**-**
VQ 4	Load / DG switch / storage / DSM (smart grid)	**+**	**+**
SP 1	New circuit breaker (CB) with protection	**0**	**0**
SP 2	New CB with protection and communication	**-**	**-**

SP 3	Area wide communication / protection via control	**-**	**--**
CS 1	Balancing (more balancing necessary due to DG)	**0**	**+**
CS 2	Ancillary services (more ancillary services)	**0**	**+**
CS 3	Area wide control with DSM and storage	**0**	**+**
DE 1	Capacity payment (investment incentive)	**-**	**-**
DE 2	DG incentive for DSO	**+**	**+**
DE 3	Active ditribution grid	**0**	**+**

Cost compared to DSO without DG (as today)

++	considerably less cost to be expected
+	less cost to be expected
0	neutral
-	more cost to be expected
--	significantly more cost to be expected

Time

++	possible with already installed equipment
+	short investment cycle, replacement in due time
0	new standard equipment necessary
-	medium investment cycle or new application to be developed
--	long investment cycle or new standards with new developments necessary

Table 36, assessment of opportunities with ripple control

Id.No.	**Description**	**Revenue**	**time**
CS 1	Balancing (participate in balancing market)	**++**	**+**
CS 2	Ancillary services (participate in ancillary market)	**++**	**+**
DE 3	Active distribution grid (with incentive regulation)	**+**	**--**

Revenues[18]

++	considerably revenues to be expected
+	some revenues to be expected
0	neutral
-	some more costs to be expected
--	significant costs to be expected

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[18] Revenues in the regulation schemes as today is not relevant (cost +) but benchmark regulation for DSOs in the near future is considered.

Time

++	immediately applicable
+	shortly after small changes applicable
0	applicable to the next business year
-	change of contracts, business model and /or legal ordinance necessary
--	major change of law, regulation scheme necessary

6.2.1 Summary of results of assessment regarding opportunities and problems with ripple control

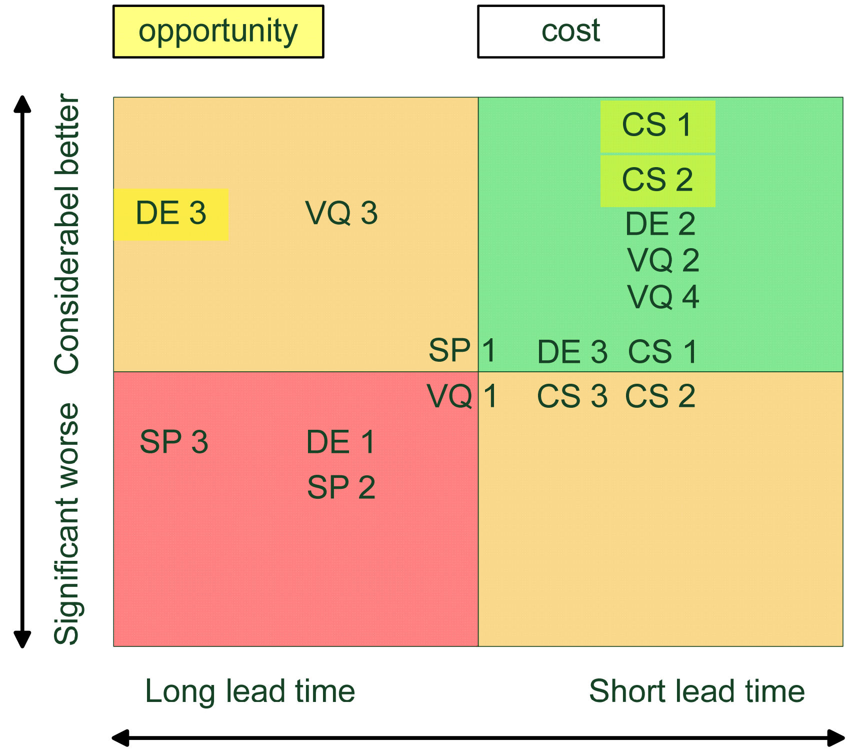

Figure 31, Matrix with problems / opportunities using ripple control

The results show a clear move of problems towards the green quadrant which means expecting less problems and lower costs by shorter lead time which would finally foster the integration of DG in MV and LV networks.

6.2.2 Summary of results of DG integration and impact on grid control and stability with ripple control

Simple control functionality as provided by ripple control reduces the impact of problems drastically and improves the possible penetration of DG.
The indicators are:

- Network losses kept in optimum (balance of load and generation)
- Balancing impact lower and compensated with participation in balancing.
- Increase of load curve spread starting above 40% (see above) but peak reduction considerable (see chapter 3)

Table 37, summary of impact of DG / max. load with ripple control

Impact	🟩	🟩	🟩	🟧	🟧
DG / max. Load	25%	50%	75%	100%	125%

7 Conclusion

7.1 Increasing DG integration in distribution networks

A DG production in MV and LV networks up to 100% and more is achievable taking into consideration that the installed capacity is approximately the same size as the expected peak load including the simultaneity factor.

DG integration with conventional solutions like network reinforcement and no control of load or DG-production is applicable but DG concentration in network areas must be restricted to approximately 50 % of load (shows increasing problematic effect after 25%). If they are not restricted problems on grid stability and control with additional costs from increased balancing, ancillary services and losses can be expected. This means adequacy and security of supply could not be guaranteed any longer.

A DG concentration greater than 50% of the load is possible but they should be controllable (preferably already if ≥.25%) That means the operation of the DG should follow the load curve in the network area there DG is located. It endorses the reduction of losses, peak load and as a result also the energy transport through the upper network levels. In addition it facilitates the DSO to provide ancillary services and balancing for the upper network levels as well as for his own network and opens the opportunity to generate additional revenues.

In networks with already installed ripple control system this controllability could be implemented without lead time. The hardware cost for new ripple control receivers (e.g. with more channels) is negligible. However, the implementation of new business models and / or contractual arrangements with DG operators can create relevant obstacles for the management and might need a change in attitude.

Finally it is a valuable transitory solution using ripple control until smart grid approach can be implemented and normative elements are fully adapted.

7.2 Further questions

The technical solutions are widely discussed but business solutions and regulatory schemes should be discussed further. A new approach for the cost allocation in the different network levels must be found in order not to penalise the network operators which support DG. This means a better solution for tariffs according to maximum peak load and energy demand and not based on supplied energy in the network area. The aim should be to incentivise the DSO for managing his network in order to use as much as possible local produced energy. This would help to avoid network reinforcement on higher levels and transmission losses. The regulator schemes for such incentives should be studied further and implemented quickly.

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