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Integration of Distributed Generation in Low Voltage Networks: Power Quality and Economics

By

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Declaration of author's rights:

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Abstract

Distributed generation (DG) is an emerging concept in the electricity sector, which represents good alternatives for electricity supply instead of the traditional centralized power generation concept.

This Thesis presents the basic principles of integrating distributed generation technologies in low voltage networks and particularly focuses on the economics of DG installations and the impact that DG may have on voltage control leading to improved power quality.

The first three chapters provide a DG background containing the current status, applications, technologies and basic issues. In chapters 4 and 5 the relation between DG and Power Quality is investigated and solutions for better voltage control with DG are presented. Chapters 6 and 7 are focused on a case study in a DG installation test site in Germany followed by the conclusions.

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1. Introduction

The liberation of the energy market and the new conditions in the energy field are leading towards the finding of more efficient ways of energy production and management. The introduction of new ideas capable of evolving in the new conditions might lead to more suitable solutions compared to any possible malfunctions the new market model can create.

The electricity marketplace is undergoing a tremendous transformation as it moves towards a more competitive environment. The 'growing pains' of this transformation – price instability, an ageing infrastructure, changing regulatory environments – are causing both energy users and electric utilities to take another look at the benefits of distributed generation(DG).[1]

The combination of utility restructuring, technology evolutions, recent environmental policies provide the basis for DG to progress as an important energy option in the near future. Utility restructuring opens energy markets, allowing the customer to choose the energy provider, method of delivery, and attendant services. The market forces favour small, modular power technologies that can be installed quickly in response to market signals.

This restructuring comes at a time when:

- Demand for electricity is escalating domestically and internationally;
- Impressive gains have been made in the cost and performance of small, modular distributed generation technologies
- Regional and global environmental concerns have placed a premium on efficiency and environmental performance; and
- Concerns have grown regarding the reliability and quality of electric power. [2]

2. Distributed Generation Background

2.1. Definition

Generally, the term Distributed or Distributed Generation refers to any electric power production technology that is integrated within distribution systems, close to the point of use. Distributed generators are connected to the medium or low voltage grid. They are not centrally planned and they are typically smaller than 30 MW_e (DTI 2001). [3]

The concept of DG contrasts with the traditional centralised power generation concept, where the electricity is generated in large power stations and is transmitted to the end users through transmission and distributions lines (see figure.1). While central power systems remain critical to the global energy supply, their flexibility to adjust to changing energy needs is limited. Central power is composed of large capital-intensive plants and a transmission and distribution (T&D) grid to disperse electricity.

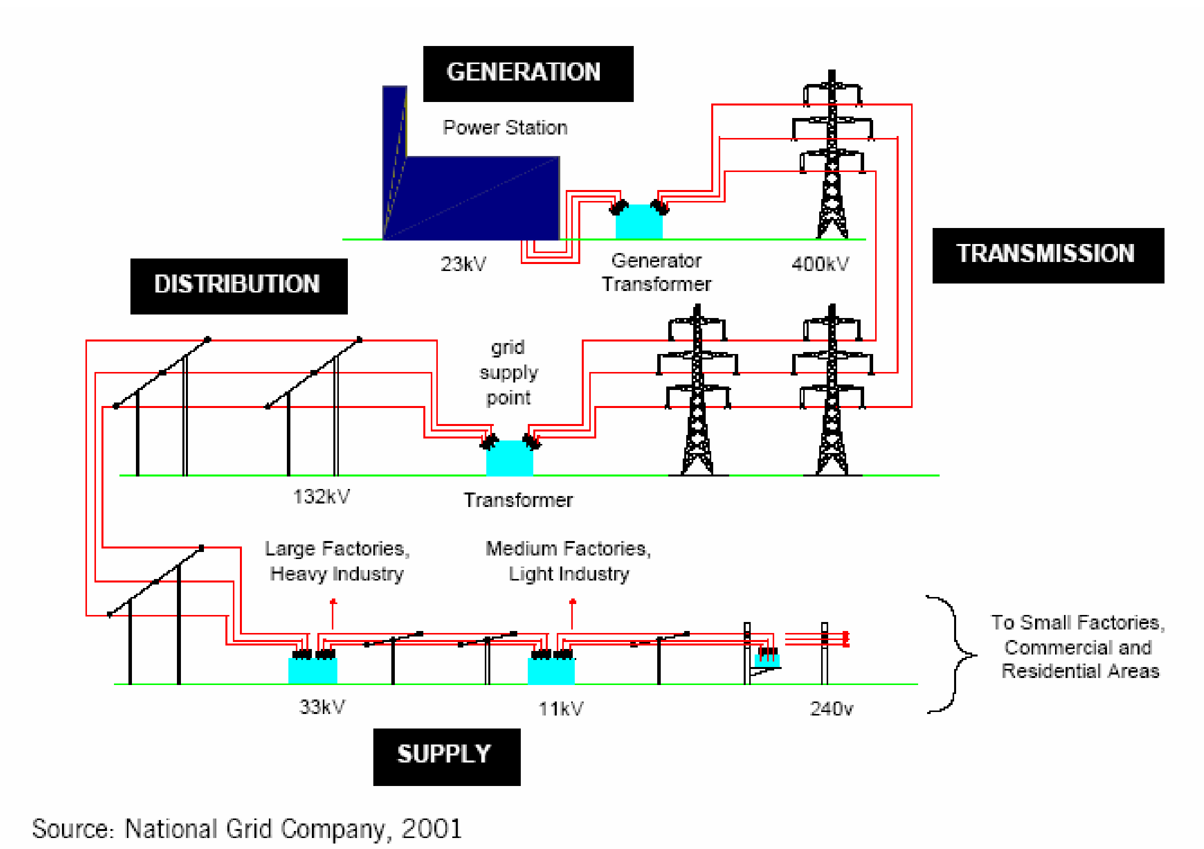


Figure 2-1. An electric power system

A distributed electricity system is one in which small and micro generators are connected directly to factories, offices, households and to lower voltage distribution networks. Electricity not demanded by the directly connected customers is fed into the active distribution network to meet demand elsewhere. Electricity storage systems may be utilised to store any excess generation. Large power stations and large-scale renewables, e.g. offshore wind, remain connected to the high voltage transmission network providing national back up and ensure quality of supply. Again, storage may be utilised to accommodate the variable output of some forms of generation. Such a distributed electricity system is represented in figure 2-2 below.

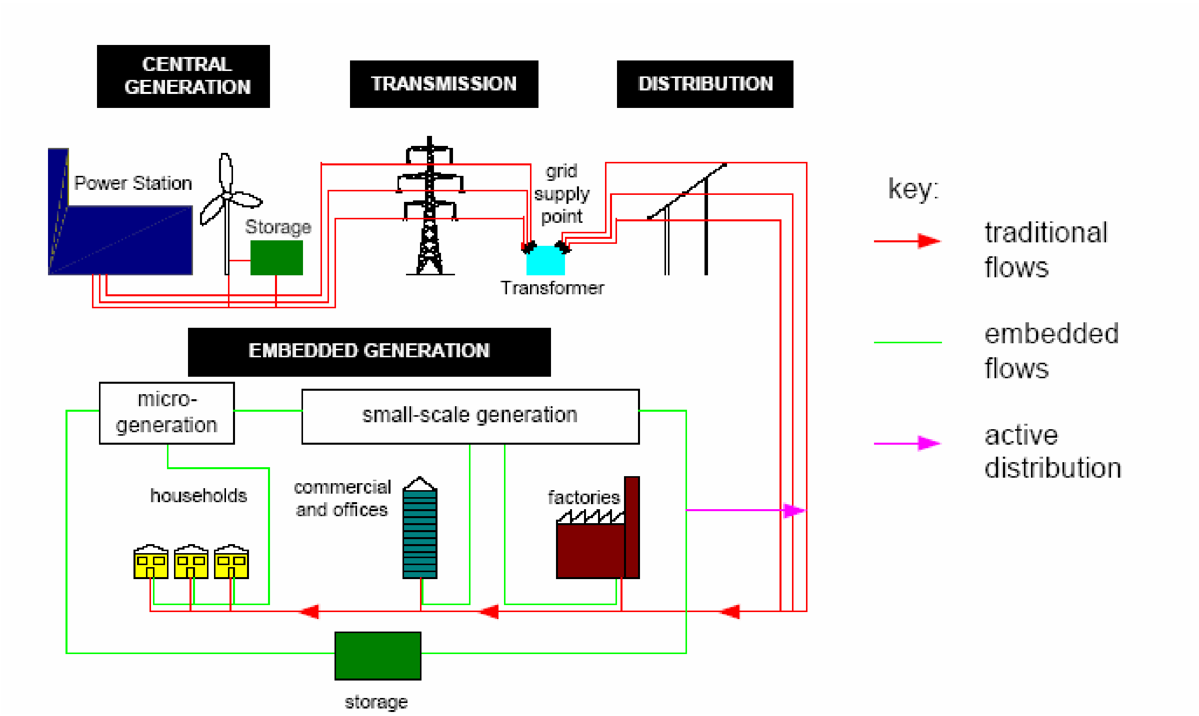


Figure 2-2. A Distributed Electricity System

The non-traditional operating model of DG has drawn strong interest because of its potential to cost effectively increase system capacity while meeting the industry restructuring objective of market-driven, customer-oriented solutions. These distributed generation systems, capable of operating on a broad range of gas fuels, offer clean, efficient, reliable, and flexible on-site power alternatives. This emerging portfolio of distributed generation options being offered by energy service companies and independent power producers is changing the way customers view energy.

Both options require significant investments of time and money to increase capacity. Distributed generation complements central power by (1) providing in many cases a relatively low capital cost response to incremental increases in power demand, (2) avoiding T&D capacity upgrades by locating power where it is most needed, and (3) having the flexibility to put power back into the grid at user sites. Significant technological advances through decades of intensive research have yielded major improvements in the economic, operational, and environmental performance of small, modular gas-fuelled power generation options. Forecasts predict a total 520GW from newly installed DG around the globe by 2030. [4]

2.2. Market

DG appears especially attractive to policymakers, regulators and the market generally because it provides the option of reducing investments in transmission and distribution systems and also the option of minimizing the T&D energy losses.

One of the powerful forces driving that transition in the market structure has been advances in electricity generation technologies that have reduced the costs of smaller-capacity systems. Technologies such as microturbines are available in capacities under 100 kilowatts (roughly the size of an automobile engine). Large-scale power plants (100 megawatts or greater), which are typically used by vertically integrated utilities, no longer have significantly lower costs than smaller plants do. That change has weakened one of the main rationales for maintaining electric power production as a regulated monopoly and the next reasonable step would be to fully exploit the savings in generation and transmission costs from large-scale, centrally located power plants.

Policymakers have an interest in the future of distributed generation, not only for the cost savings it can provide to the homes and businesses that produce it but also for the cost savings and additional reliability that it may be able to offer to the entire electricity market. Distributed generation may play a larger role, along with demand-management techniques and further innovations in wholesale and retail markets, in reducing the cost of electricity when traditional supply is tight or market demand is strong. For example, distributed generation may offer retail customers greater flexibility to alter their demand for electricity in response to hourly changes in prices (real-time pricing), thereby promoting the efficient operation and stability of energy markets as they become increasingly competitive. Some observers expect distributed generation to play a role in the commercial development of renewable energy and high-efficiency technologies, adding the associated environmental and safety benefits.

2.3. Technology Status

The technical and commercial status of distributed generation globally depends very much on the past history of a country's power industry. Countries, whether developed or developing, with power sectors that are largely state controlled either remain tied to a centrally controlled transmission system that is connected to large-scale fossil fuel, hydro or nuclear power stations, or are developing such systems. Countries where liberalisation has taken place, on the other hand, have the incentive to consider alternatives. It is in these countries that distributed generation has started to gain a foothold because of its lower capital cost, modular construction and short build times.

The mix of distributed generation technologies exploited depends on, among other things, energy market and political issues. The USA probably leads the world in developing distributed generation, driven by commercial issues and by poor power quality and the lack of security of supply in a number of states. In other words, the market is demanding solutions that distributed generation technologies can provide. This has resulted in a distributed generation market that is dominated by low-cost, high-reliability fossil-fuel plant (usually gas-based) but that has a growing renewables component. [5]

Progress in Europe is slower because, in many countries, the process of liberalisation has only recently started and power supplies are generally of good quality. To date, the main driver in Europe has been environmental concern. This has resulted in the extensive development of renewable technologies although, at present, these are generally more costly than other forms of generation and therefore rely on government support to achieve significant market penetration. [6]

2.4. Distributed Generation Applications and Technologies

2.4.1. DG Applications

Distributed generation (DG) is currently being used by some customers to provide some or all of their electricity needs. There are many different potential applications for DG technologies. For example, some customers use DG to reduce demand charges imposed by their electric utility, while others use it to provide primary power or reduce environmental emissions. DG can also be used by electric utilities to enhance their distribution systems. Many other applications for DG solutions exist. The following is a list of those of potential interest to electric utilities and their customers.

Continuous Power - In this application, the DG technology is operated at least 6,000 hours a year to allow a facility to generate some or all of its power on a relatively continuous basis. Important DG characteristics for continuous power include:

- High electric efficiency,
- Low variable maintenance costs
- Low emissions

Currently, DG is being utilized most often in a continuous power capacity for industrial applications such as food manufacturing, plastics, rubber, metals and chemical production. Commercial sector usage, while a fraction of total industrial usage, includes sectors such as grocery stores and hospitals.

Combined Heat and Power (CHP) - Also referred to as Cooling, Heating, and Power or cogeneration, this DG technology is operated at least 6,000 hours per year to allow a facility to generate some or all of its power. A portion of the DG waste heat is used for water heating, space heating, steam generation or other thermal needs. In some instances this thermal energy can also be used to operate special cooling equipment. Important DG characteristics for combined heat and power include:

- High useable thermal output (leading to high overall efficiency),
- Low variable maintenance costs
- Low emissions

CHP characteristics are similar to those of Continuous Power, and thus the two applications have almost identical customer profiles, though the high thermal demand here is not necessary for Continuous Power applications. As with Continuous Power, CHP is most commonly used by industry clients, with a small portion of overall installations in the commercial sector.

Peaking Power - In a peaking power application, DG is operated between 200-3000 hours per year to reduce overall electricity costs. Units can be operated to reduce the utility's demand charges, to defer buying electricity during high-price periods, or to allow for lower rates from power providers by smoothing site demand. Important DG characteristics for peaking power include:

- Low installed cost
- Quick startup
- Low fixed maintenance costs

Peaking power applications can be offered by energy companies to clients who want to reduce the cost of buying electricity during high-price periods. Currently DG peaking units are being used mostly in the commercial sector, as load profiles in the industrial sector are relatively flat. The most common applications are in educational facilities, lodging, miscellaneous retail sites and some industrial facilities with peaky load profiles.

Green Power - DG units can be operated by a facility to reduce environmental emissions from generating its power supply. Important DG characteristics for green power applications include:

- Low emissions
- High efficiency
- Low variable maintenance costs

Green power could also be used by energy companies to supply customers who want to purchase power generated with low emissions.

Premium Power - DG is used to provide electricity service at a higher level of reliability and/or power quality than typically available from the grid. The growing premium power market presents utilities with an opportunity to provide a value-added service to their clients. Customers typically demand uninterrupted power for a variety of applications, and for this reason, premium power is broken down into three further categories:

Emergency Power System - This is an independent system that automatically provides electricity within a specified time frame to replace the normal source if it fails. The system is used to power critical devices whose failure would result in property damage and/or threatened health and safety. Customers include apartment, office and commercial buildings, hotels, schools, and a wide range of public gathering places.

Standby Power System - This independent system provides electricity to replace the normal source if it fails and thus allows the customer's entire facility to continue to operate satisfactorily. Such a system is critical for clients like airports, fire and police stations, military bases, prisons, water supply and sewage treatment plants, natural gas transmission and distribution systems and dairy farms.

True Premium Power System - Clients who demand uninterrupted power, free of all power quality problems such as frequency variations, voltage transients, dips, and surges, use this system. Power of this quality is not available directly from the grid – it requires both auxiliary power conditioning equipment and either emergency or standby power. Alternatively, a DG technology can be used as the primary power source and the grid can be used as a backup. This technology is used by mission critical systems like airlines, banks, insurance companies, communications stations, hospitals and nursing homes.

Important DG characteristics for premium power (emergency and standby) include:

- Quick startup,
- Low installed cost
- Low fixed maintenance costs

Transmission and Distribution Deferral - In some cases, placing DG units in strategic locations can help delay the purchase of new transmission or distribution systems and equipment such as distribution lines and substations. A detailed analysis of the life-cycle costs of the various alternatives is critical and issues relating to equipment deferrals must also be examined closely. Important DG characteristics for transmission and distribution deferral (when used as a "peak deferral") include:

- Low installed cost

- Low fixed maintenance costs

Ancillary Service Power - DG is used by an electric utility to provide ancillary services (interconnected operations necessary to affect the transfer of electricity between the purchaser and the seller) at the transmission or distribution level. In markets where the electric industry has been deregulated and ancillary services unbundled (in the United Kingdom, for example), DG applications offer advantages over currently employed technologies. Ancillary services include spinning reserves (unloaded generation, which is synchronized and ready to serve additional demand) and non-spinning, or supplemental, reserves (operating reserve is not connected to the system but is capable of serving demand within a specific time or interruptible demand that can be removed from the system within a specified time). Other potential services range from transmission market reactive supply and voltage control, which uses generating facilities to maintain a proper transmission line voltage, to distribution level local area security, which provides back up power to end users in the case of a system fault. The characteristics that may influence the adoption of DG technologies for ancillary service applications will vary according to the service performed and the ultimate shape of the ancillary service market [7] [8] [9]. Figure 2-3 summarises the different kinds of DG applications.

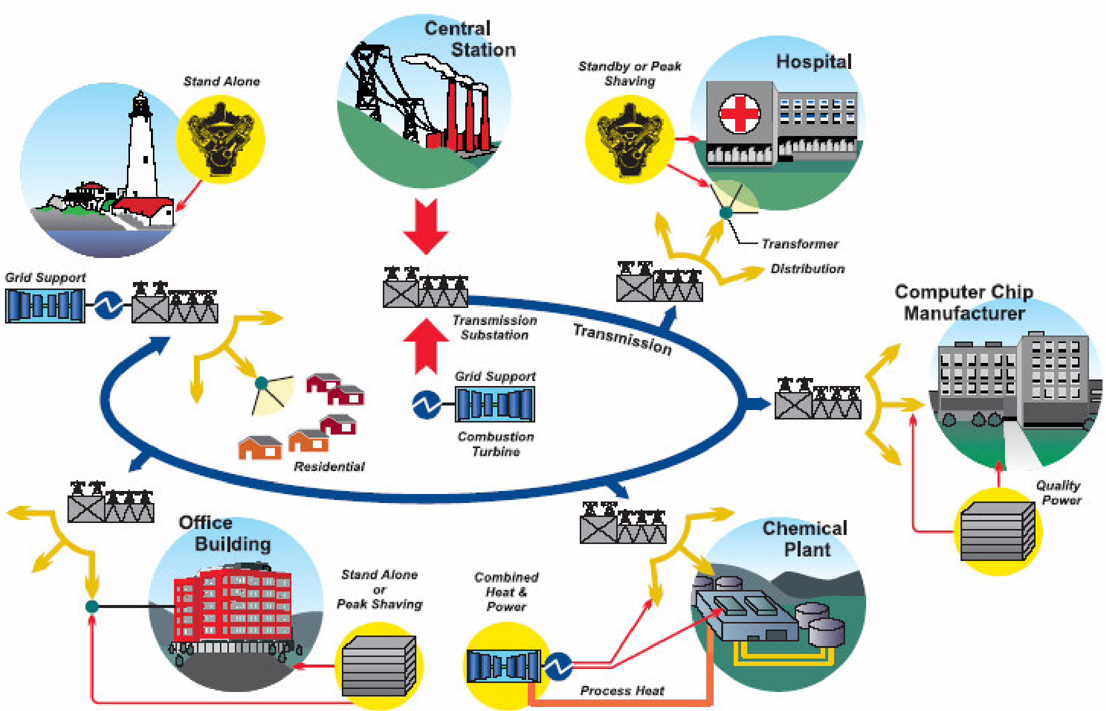


Figure 2-3. Summary of DG applications [2]

2.4.2. DG Technologies

Reciprocating engines - This DG technology was developed more than a century ago, and is still widely utilized in a broad array of applications. The engines range in size from less than 5 to over 5,000 kW, and use diesel, natural gas, or waste gas as their fuel source. Development efforts remain focused on improving efficiency and on reducing emission levels. Reciprocating engines are being used primarily for backup power, peaking power, and in cogeneration applications.

Microturbines - A new and emerging technology, microturbines are currently only available from a few manufacturers. Other manufacturers are looking to enter this emerging market, with models ranging from 30 to 200 kW. Microturbines promise low emission levels, but the units are currently relatively expensive. Obtaining reasonable costs and demonstrating reliability will be major hurdles for manufacturers. Microturbines are just entering the marketplace, and most installations are for the purpose of testing the technology.

Industrial combustion turbines - A mature technology, combustion turbines range from 1 MW to over 5 MW. They have low capital cost, low emission levels, but also usually low electric efficiency ratings. Development efforts are focused on increasing efficiency levels for this widely available technology. Industrial combustion turbines are being used primarily for peaking power and in cogeneration applications.

Photovoltaics - Commonly known as solar panels, photovoltaic (PV) panels are widely available for both commercial and domestic use. Panels range from less than 5 kW and units can be combined to form a system of any size. They produce no emissions, and require minimal maintenance. However, they can be quite costly. Less expensive components and advancements in the manufacturing process are required to eliminate the economic barriers now impeding wide-spread use of PV systems. Photovoltaics are currently being used primarily in remote locations without grid connections and also to generate green power.

Fuel Cells - Fuel cells are not only very efficient but also have very low emission levels. A fuel cell operates like a battery. It supplies electricity by combining hydrogen and oxygen electrochemically without combustion. However, while the battery is a storage device for energy that is eventually used up and/or must be recharged, the fuel cell is permanently fed with fuel and an oxidant, so that the electrical power generation continues. The final product is pure water; the electrochemical reaction generates electricity and heat without a flame ("cold combustion"). A single cell provides less than one volt, so a series of fuel cells are normally "stacked" one on another to increase the power output. The basic fuel cell has two electrodes separated by an electrolyte. One of the electrodes (the anode) is supplied with the fuel (for example, hydrogen or natural gas). The second electrode (the cathode) is supplied with oxygen by simply pumping air in. The few fuel cells currently being used provide premium power. There are several types of fuel cells. Proton exchange membrane fuel cells are now days the most commercially available type. They have the highest energy density per volume rate and their prices are expected to fall fast because they are being adapted by the automotive industry for transportation use [10]. A summary of the different types of fuel cells and their technical characteristics can be seen in table 2-1.

Table 2-1 Fuel cell types and technical characteristics

Type	Operation Temp. °C	Electrolyte	Fuel	Efficiency %	Application	Stage
AFC	80 to 90	caustic potash solution	Hydrogen	50 to 65	Transport, marine propulsion, aerospace	Early commercial
PEM	80 to 90	Polymer membrane (Nafion)	Hydrogen, reformed methanol or methane	50 to 65	Transport, electric car, marine propulsion, aerospace	Early development and testing
PAFC	200	Phosphoric acid	Hydrogen, reformed methane	35 to 45	1-100 MW power plants 50-500 kW heat plants	Early commercial
MCFC	650	Calcium carbonate	Hydrogen, methane	45 to 60	1 to 1-100 MW power plants 50-500 kW heat plants	Field test or demonstration
SOFC	850 to 1000	Zircon oxide	Hydrogen, methane, carbon gas	50 to 60	1-100 MW power plants 50-500 kW heat plants	Field test or demonstration

Source: Onsyte Sycom Energy Corporation (1999), *The Role of Distributed Generation in Competitive energy Markets*, p. 3; Niehus, C. (1998),*Vorlesungsskript:Brennstoffzellentechnologien*,

Wind turbine systems - Wind turbines are currently available from many manufacturers and range in size from less than 5 to over 1,000 kW. They provide a relatively inexpensive (compared to other renewables) way to produce electricity, but as they rely upon the variable and somewhat unpredictable wind, are unsuitable for continuous power needs. Development efforts look to pair wind turbines with battery storage systems that can provide power in those times when the turbine is not turning. Wind turbines are being used primarily in remote locations not connected to the grid and by energy companies to provide green power.

2.4.3. The Cost Structure of Distributed Generation Technologies

The direct costs of distributed generation to customers include the installed cost of the equipment, fuel costs, nonfuel operation and maintenance (O&M) expenses, and certain costs that the customers' utility imposes.

In order to make this comparison of costs most useful, the following cost data are based on the assumption that for each technology there are used an installed capacity, a rate of utilization, and (in some cases) a geographic location that would be suitable for serving the electricity needs of individual customers. For example, the costs for the wind turbine discussed here are for a size that might be used in a small rural business (such as a farm) in a location with favourable wind resources. On that basis, data compiled from various industry and government sources describe the current costs of the most common types of electricity generation technologies (Table 2-2). Data for a combined-cycle unit are presented as well; as the largest source of additional electricity from utilities and independent power producers, combined-cycle systems provide a representative benchmark against which the costs of other technologies can be measured.

2.4.4. Capital Costs

The costs of acquiring and installing generating units vary widely, depending on technology, capacity, and other factors. The U.S. Department of Energy estimates that the typical installed capital costs for distributed generators range from under $1,000 per kilowatt for a combustion turbine to almost $7,000 per kilowatt for a solar photovoltaic system [11]. Among small-capacity technologies, internal combustion engines (fuelled by diesel and gasoline) have the lowest capital costs and highest operating costs. Renewable technologies (using wind and solar power) have the highest capital costs and lowest operating costs. New high-efficiency technologies (microturbines and fuel cells) fall in between. Table 2-2 shows the costs of the basic DG technologies.

Table 2-2 A summary of DG technologies' costs

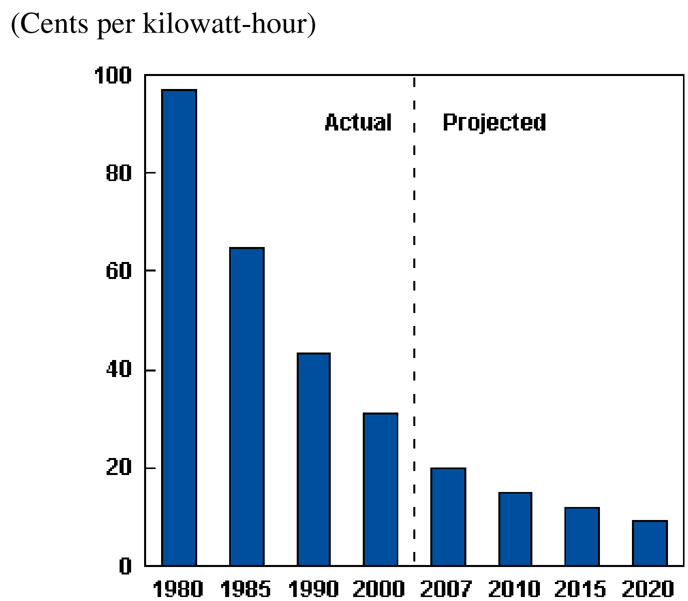
	Capacity (KW)	Capital cost ($/KW)	Fuel Cost ($/KWh)	O&M cost ($/KWh)	Service life (years)	Heat Rate (BTU/KWh)
Micro turbine--Power Only	100	1,485	0.075	0.015	12.5	13,127
Microturbine--CHP	100	1,765	0.035	0.015	12.5	6,166
Gas ICE—Power Only	100	1,030	0.067	0.018	12.5	11,780
Gas ICE--CHP	100	1,491	0.027	0.018	12.5	4,717
Fuel Cell--CHP	200	3,674	0.029	0.010	12.5	5,106
Solar Photovoltaic	100	6,675	0	0.005	20	n.a.
Small Wind Turbine	10	3,866	0	0.005	20	n.a.
Large Wind Turbine	1,000	1,500	0	0.005	20	n.a.
Combustion Turbine--Power Only	10,000	715	0.067	0.006	20	11,765
Combustion Turbine--CHP	10,000	921	0.032	0.006	20	5,562
Combined-Cycle System	100,000	690	0.032	0.006	20	5,642

Source: Congressional Budget Office based on data from the Department of Energy's National Renewable Energy Laboratory and Energy Information Administration; Bergey Windpower Company; and the California Energy Commission [11]

2.4.5. Trends in Costs

The capital and operating costs of certain distributed generation technologies have fallen significantly in recent years and can be expected to continue to do so. In the case of one technology, photovoltaic systems, the cost per delivered kilowatt-hour in suitable applications has plummeted by almost 70 percent since 1980, and it is projected to decline by another 70 percent from current levels by 2020 (see fig.4)[12]

Similarly, developers forecast that fuel cells will improve in performance and decline in cost over the next several years to the point that they will soon be suitable for widespread use in distributed generation. A recent study by Lawrence Berkeley National Laboratory projected that the installed cost per kilowatt for a 200-kilowatt fuel cell would drop from $3,500 in 2000 to $1,300 (in 2000 dollars) by 2010[13].



Source: Congressional Budget Office based on data from Department of Energy, Office of Energy Efficiency and Renewable Energy, and Electric Power Research Institute, *Renewable Energy Technology Characterizations*, EPRI-TR-109496 (December 1997).

Figure 2-4. Levelized Cost of Solar Photovoltaic Electricity, 1980 to 2020

3. Benefits and Issues of DG

3.1. Benefits of DG

3.1.1. Customer Benefits

- Properly located, installed and operated DG can improve reliability of energy supply, increasingly critical to business and industry in general, and essential to some where interruption of service is unacceptable economically or where health and safety is impacted;[14]
- The various DG technologies offer the opportunity of selecting the right energy solution at the right location. DG technologies can provide a stand-alone power option for areas where transmission and distribution infrastructure does not exist or is too expensive to build;
- DG may offer efficiency gains for on-site applications by avoiding line losses, and using both electricity and the heat produced in power generation for processes or heating and air conditioning;
- Its flexibility of operation because of small modular units enables savings on electricity rates by self generating during high-cost peak power periods and adopting relatively low cost interruptible power rates;
- Benefits for environmental quality may come from distributed generation's role in promoting renewable energy sources, less-polluting forms of fossil energy, and high-efficiency technologies. DG allows power to be delivered in environmentally sensitive and pristine areas by having characteristically high efficiency and near-zero pollutant emissions;
- Affords customers a choice in satisfying their particular energy needs; and
- Provides siting flexibility by virtue of the small size, superior environmental performance, and fuel flexibility.

3.1.2. Supplier Benefits

- DG limits capital exposure and risk because of the size, siting flexibility, and rapid installation time afforded by the small, modularly constructed, environmentally friendly, and fuel flexible systems;
- Unnecessary capital expenditure can be prevented by closely matching capacity increases to growth in demand;
- DG avoids major investments in transmission and distribution system upgrades by siting new generation near the customer;

- It offers a relatively low cost entry point into a new and competitive market; and
- Opens markets in remote areas without transmission and distribution systems, and areas without power because of environmental concerns.

3.1.3. National Benefits

- Distributed generation technologies that relied on renewable energy sources could yield environmental benefits in the form of reduced emissions of pollutants and greenhouse gases if those technologies displaced utility-supplied power, much of which is generated from coal. Technologies that relied on conventional fuels would yield environmental benefits if they resulted in a shift to less-polluting energy sources-for example, natural gas rather than coal. High-efficiency technologies could yield benefits by reducing the amount of energy required to produce a unit of electricity.[15]
- DG responds to increasing energy demands and pollutant emission concerns while providing low-cost, reliable energy essential to maintaining competitiveness in the world market; and
- Establishes a new industry worth billions of dollars in sales and hundreds of thousands of jobs and enhances productivity through improved reliability and quality of power delivered, valued at billions of dollars per year.

3.2. Issues of DG

3.2.1. DG Electrical Interconnection

The interconnection with the network is a complicated procedure that involves the realization of a DG application. The DG operation is usually referred to as synchronised or parallel operation. In this configuration the DG is connected to the network the same time that it's producing power and in the case that the load is met any excess energy is also transmitted to that.

The parallel DG operation is the most complicated in contrast with a stand-alone DG application. The complexity of DG operation generally depends on the level of interaction with the existing network.

- Isolated, stand alone source (fig.3-1):
  In this case the load is met by DG only with no network connection

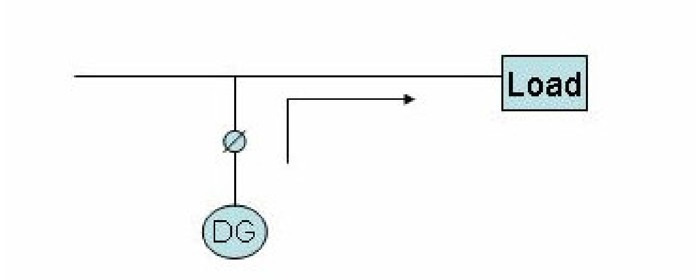


Figure 3-1. Isolated, stand alone source

- Isolated system with automatic transfer (fig.3-2):

  DG provides power in Load 2. The network covers Load 1 and Load 2 when needed. DG does not work in parallel except for a few sec.

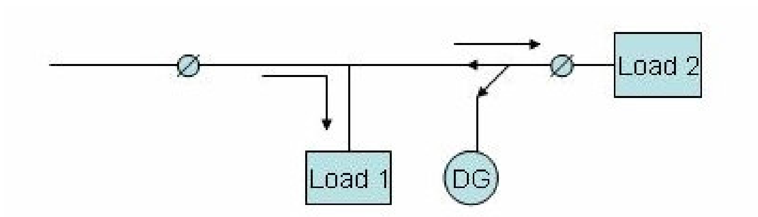


Figure 3-2. Isolated system with automatic transfer

- DG connected to the network with no power export (fig.3-3):

  DG operates in parallel to the grid by transmitting power to one or more loads without sending any excess energy to the grid

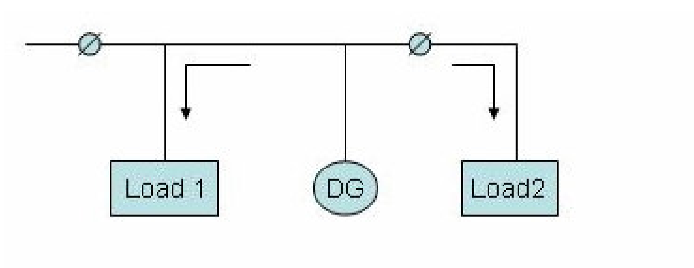


Figure 3-3. DG connected to the network with no power export

- DG grid interconnected with power export (fig.3-4):

  DG operates in parallel to the grid and there exists the option to supply any excess power to the grid.

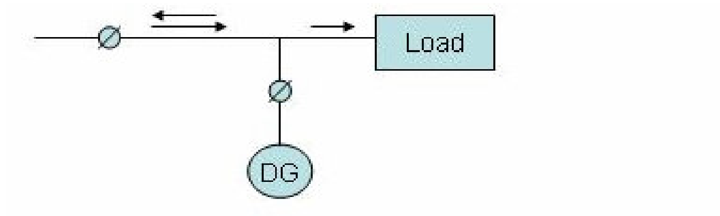


Figure 3-4. DG grid interconnected with power export

- Grid interconnected with power export- utility side (fig.3-5):
  The system supplies the base load, standby power, and peak load. DG operates in parallel

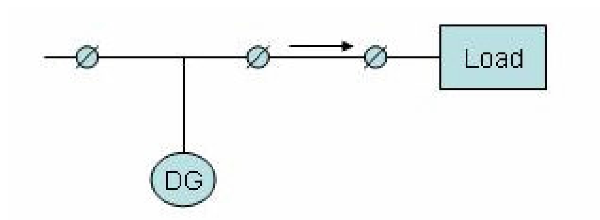
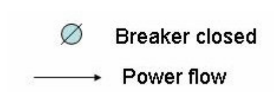


Figure 3-5. Grid interconnected with power export- utility side



3.2.2. Technical issues

The main technical issues for DG connection relate to reliability and quality of supply, protection, metering, and operating protocols for connection and disconnection, islanding and reactive power management. Voltage regulation, voltage flicker, harmonic voltages and DC injection are key quality of supply issues. Protection issues arise both for DG equipment and network equipment. The DG protection issues depend on the type of generator and the characteristics of the network. Network protection issues depend on the type and location of the DG installation and network characteristics. Thus protection design requires good communication between DG project developer and network service provider during the design process.

It may be difficult to develop economically sound policies on how to pay for any required upgrades in the utility infrastructure to protect against those risks. Experts generally agree that the current risks to the distribution system from the parallel operation of small generators, representing only a small fraction of a local distribution network's capacity, are usually manageable. But the cumulative effects of many generators would be another matter. The utility network might require significant upgrades and additional protective devices to manage distributed generators that could use a large fraction of the local distribution network's capacity. [16]

3.2.3. Protection Issues

Power system protection is a technical issue that is sufficiently important to deserve separate discussion. The objective of power system protection is to detect a fault condition (perhaps due to a lightning strike or equipment failure) and isolate the faulted section of the system as rapidly as possible while restoring normal operation to the rest of the system.

Connecting DG to a distribution network introduces a source of energy at a point where there may not have been a source before. This may increase the “fault level” in the network (that is, the fault current that may flow when a fault occurs) and may complicate fault detection and isolation. In a typical urban network, DG may be connected at voltage levels ranging from 240V single phase to 132 kV (line-line). Connections at 132 kV are complex but well understood, whereas connections at 240/415V and 11 kV can be more difficult, particularly if they involve net injections into the network. [17]

The goal of protection design in the presence of DG is to maintain the pre-existing standard of network reliability, security and quality, coordinate with existing network protection and provide reasonable backup. Protection engineers recommend the use of dedicated, utility quality protection devices rather than rely on DG control equipment that is used in normal operation. Because each DG installation involves a unique combination of generation and system factors, protection must be designed for each project, and should be undertaken as early in project design as possible.

3.2.4. Commercial and Planning Issues

Uncertainties surround the costs and benefits of distributed generation. In some circumstances, DG may be able to defer network augmentation costs, reduce network losses and improve power system security and quality of supply. In other circumstances, DG may impose additional power system operating costs and require investment in network assets. On the one hand, network service providers and system operators may feel that DG proponents overstate the benefits of DG, while on the other hand DG proponents may feel that network service providers and system operators overstate the costs.

This difference in views may be inevitable given the innovative nature of DG and its potential to radically change the electricity industry. However the shared nature of electricity industry operation and investment also contributes by blurring accountabilities and thus blurring both the nature of appropriate commercial obligations and assessments of whether those obligations have been met. Internationally, solutions are being pursued through uniform business practices and regulatory protocols, although this process is hampered by the rudimentary nature of retail electricity markets in which both consumers and DG participate.

Prior to the introduction of DG, distribution network planners only had to consider the effect of supply from the main grid generators. DG introduces energy sources in distribution networks where they had not existed before, with a wide variety of technology types and characteristics. As the network provides the main conduit for the distribution of electricity, the planner's main challenge is to be able to estimate and forecast the location and magnitude of DG connected to the network and to ensure that the principle objectives as set out above are achieved. DG can bring both positive and negative values from the perspective of distribution planning:

- Positives can include the potential to defer expenditure on network augmentation, reduce network losses and improve outcomes for the environment, voltage control and/or availability and quality of supply
- Negatives can include concerns about safety and protection, increased capital expenditure, deleterious effects on security and reliability of availability of supply, and worse outcomes for the local environment, voltage control and quality of supply.

DG installations must be assessed on an individual basis, with the exception of very small <10kW units, because of the variation in DG sizes and technology types, and because the impact on the network can be location specific. This results in long application processing times and may incur significant costs. With improved knowledge and understanding of the issues by all parties, the assessment of impacts will improve. For small installations, there is a need for better standardisation of conditions of connection. For larger installations, there are significant issues to be addressed which tend to result in long application processing times and unexpected costs for the proponent [18] [14].

4. DG and Power Quality

4.1. The Concept of Power Quality

The definition of power quality given in the IEEE dictionary originates in IEEE Std 1100 [21]: *Power quality is the concept of powering and grounding sensitive equipment in a matter that is suitable to the operation of that equipment.* Despite this definition the term power quality is clearly used in a more generic way.

Within the industry, alternate definitions or interpretations of power quality have been used, reflecting different points of view. Therefore, this definition might not be exclusive, pending development of a broader consensus.

A point of view of an equipment designer or manufacturer might be that power quality is a perfect sinusoidal wave, with no variations in the voltage, and no noise present on the grounding system. A point of view of an electrical utility engineer might be that power quality is simply voltage availability or outage minutes. Finally, a point of view of an end-user is that power quality or "quality power" is simply the power that works for whatever equipment the end-user is applying. While each hypothetical point of view has a clear difference, it is clear that none is properly focused.

An environment where the equipment designer or manufacturer clearly states the equipment needs, and the electrical utility engineer indicates the system delivery characteristics, and the end-user then predicts and understands the equipment operational disturbances that will likely be encountered on a yearly basis is a better scenario. This allows a cost justification to be performed by the end-user to either improve equipment operation by installing additional components or improve the electrical supply system through installation of additional, or alteration of existing components. [21]

4.2. Overview of Power Quality Phenomena

4.2.1. Overvoltage

When used to describe a specific type of *long duration variation*, refers to a measured voltage having a value greater than the *nominal voltage* for a period of time greater than 1 min. Typical values are 1.1 to 1.2 p.u. [22]

Overvoltages can be the result of load switching (e.g., switching off a large load), or variations in the reactive compensation on the system (e.g., switching on a capacitor bank). Poor system voltage regulation capabilities or controls result in overvoltages. Incorrect tap settings on transformers can also result in system overvoltages. Figure 4-1 shows a typical overvoltage waveform.

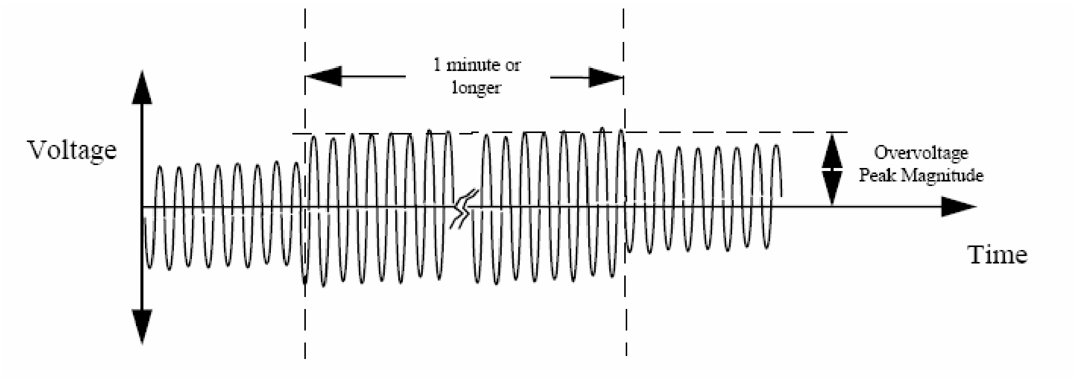


Figure 4-1. Typical overvoltage waveform [23]

4.2.2. Undervoltage

A measured voltage having a value less than the nominal voltage for a period of time greater than 1 min when used to describe a specific type of long duration variation. Typical values are 0.8 - 0.9 p.u. [22]

Undervoltages are the result of the events which are the reverse of the events that cause overvoltages. A load switching on or a capacitor bank switching off can cause an undervoltage until voltage regulation equipment on the system can bring the voltage back to within tolerances. Overloaded circuits can result in undervoltages also.

4.2.3. Sag

A sag is a decrease to between 0.1 and 0.9 p.u. in rms voltage or current at the power frequency for durations of 0.5 cycle to 1 min. Typical values are 0.1 to 0.9 p.u. [22]

To give a numerical value to sag, the recommended usage is “a sag to 20%,” which means that the line voltage is reduced down to 20% of the normal value, not reduced by 20%. Using the preposition “of” (as in “a sag of 20%,” or implied by “a 20% sag”) is deprecated. A sag is a decrease in rms voltage or current at the power frequency for durations from 0.5 cycles to 1 minute. Typical values are between 0.1 p.u and 0.9 p.u.

Terminology used to describe the magnitude of voltage sag is often confusing. A "20% sag" can refer to a sag which results in a voltage of 0.8 p.u, or 0.2 p.u. This Recommended Practice will indicate the remaining voltage throughout. Just as an unspecified voltage designation is accepted to mean line to line potential, so an unspecified sag magnitude will refer to the remaining voltage. For example, an 80% sag refers to a disturbance which resulted in a voltage of 0.8 p.u. Where possible, the nominal, or base, voltage level should be specified.

Voltage sags are usually associated with system faults but can also be caused by switching of heavy loads or starting of large motors. Figure 4-2 shows a typical voltage sag that can be associated with a single line-to-ground (SLG) fault. Also, a fault on a parallel feeder circuit will result in a voltage drop at the substation bus which affects all of the other feeders until the fault is cleared. Typical fault clearing times range from three to thirty cycles, depending on the fault current magnitude and the type of overcurrent detection and interruption.

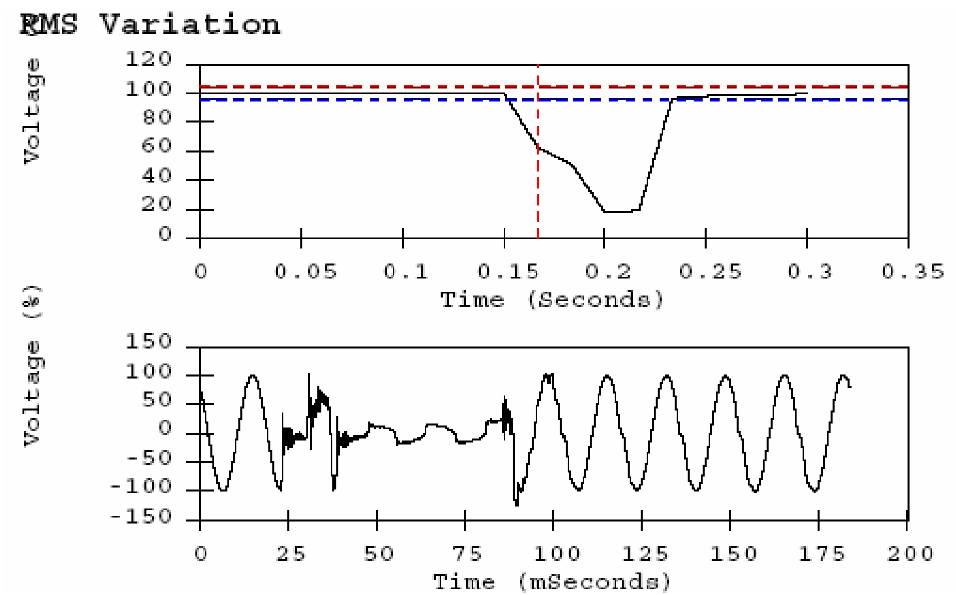


Figure 4-2. Instantaneous voltage sag caused by a SLG fault [23]

Voltage sags can also be caused by large load changes or motor starting. An induction motor will draw six to ten times its full load current during starting. This lagging current causes a voltage drop across the impedance of the system. If the current magnitude is large relative to the system available fault current, the resulting voltage sag can be significant. Figure 4-3 illustrates the effect of a large motor starting.

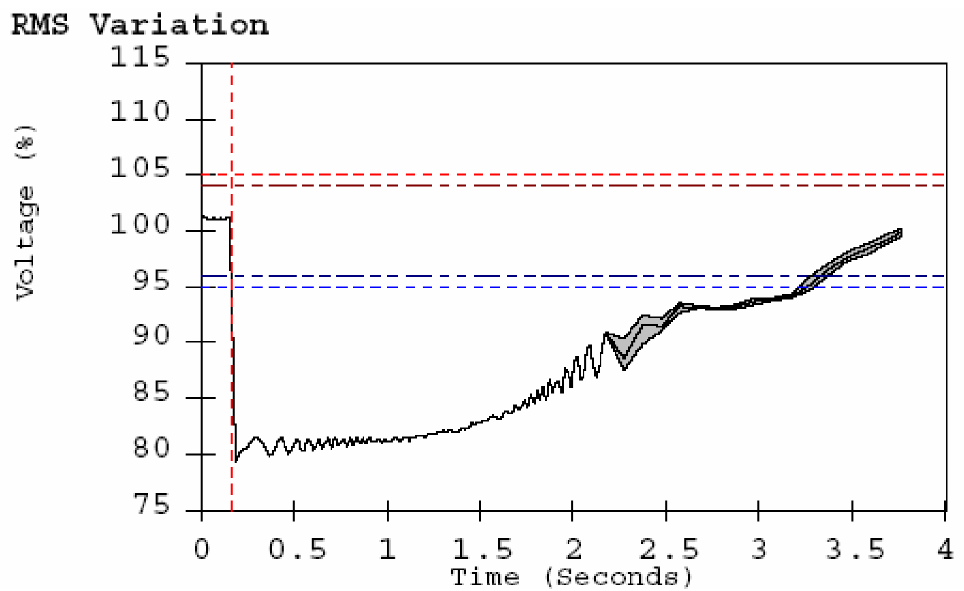


Figure 4-3. Temporary voltage sag caused by motor starting [23]

4.2.4. Swell

An increase in rms voltage or current at the power frequency for durations from 0.5 cycles to 1 min. Typical values are 1.1 - 1.8 p.u.[22]

Swell magnitude is also described by its remaining voltage, in this case, always greater than 1.1. As with sags, swells are usually associated with system fault conditions, but they are much less common than voltage sags. A swell can occur due to a single line-to-ground fault on the system resulting in a temporary voltage rise on the unfaulted phases. Swells can also be caused by switching off a large load or switching on a large capacitor bank. Figure 4-4 illustrates a voltage swell caused by a SLG fault.

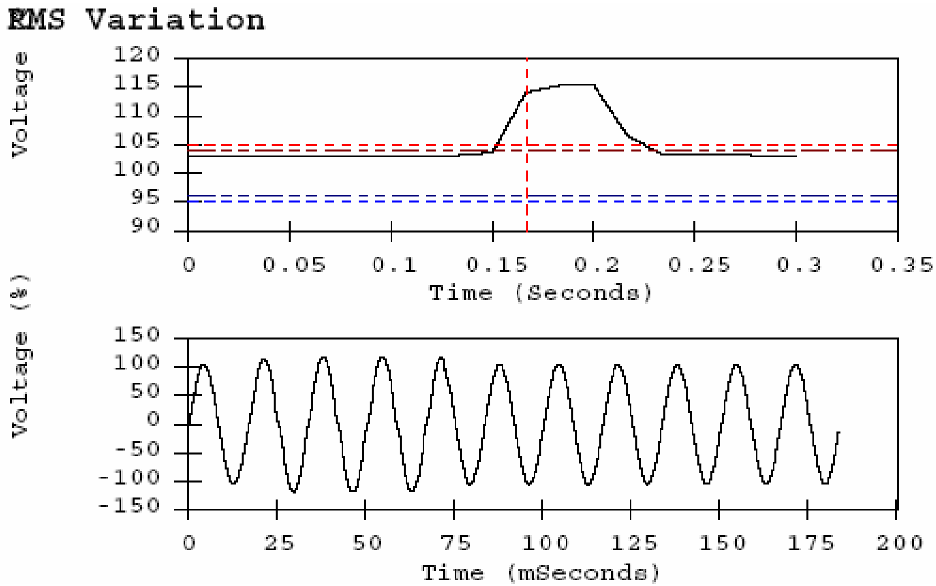


Figure 4-4. Instantaneous voltage swell caused by a SLG fault [23]

Swells are characterized by their magnitude (rms value) and duration. The severity of a voltage swell during a fault condition is a function of the fault location, system impedance, and grounding. On an ungrounded system, the line to ground voltages on the ungrounded phases will be 1.73 per unit during a line-to-ground fault condition. Close to the substation on a grounded system, there will be no voltage rise on the unfaulted phases because the substation transformer is usually connected delta-wye, providing a low impedance zero-sequence path for the fault current.

4.2.5. Transient

Pertaining to or designating a phenomenon or a quantity which varies between two consecutive steady states during a time interval that is short compared to the time scale of interest. A transient can be a unidirectional impulse of either polarity or a damped oscillatory wave with the first peak occurring in either polarity. [24]

Broadly speaking, transients can be classified into two categories, *impulsive* and *oscillatory*. These terms reflect the wave shape of a current or voltage transient. An *impulsive transient* is a sudden, non-power frequency change in the steady state condition of voltage, current, or both, that is unidirectional in polarity (primarily either positive or negative). Impulsive transients are normally characterized by their rise and decay times. These phenomena can also be described by their spectral content. For example, a 1.2/50 μs 2000-V impulsive transient rises to its peak value of 2000 V in 1.2 μs, then decays to half its peak value in 50 μs.

The most common cause of impulsive transients is lightning. Table 4.1 defines the spectral content and the duration of impulsive transients.

Table 4-1. Descriptions of impulsive transients [23]

Impulsive Transients	Spectral Content	Duration
Nanosecond	5 ns rise	< 50 ns
Microsecond	1 µs rise	50 ns – 1 ms
Millisecond	0.1 ms rise	> 1 ms

Due to the high frequencies involved, impulsive transients are damped quickly by resistive circuit components and are not conducted far from their source. There can be significant differences in the transient characteristic from one location within a building to another. Impulsive transients can excite power system resonance circuits and produce the following type of disturbance, oscillatory transients.

An *oscillatory transient* is a sudden, non-power frequency change in the steady state condition of voltage, current, or both, that includes both positive and negative polarity values. An oscillatory transient consists of a voltage or current whose instantaneous value changes polarity rapidly. It is described by its spectral content (predominant frequency), duration, and magnitude. The spectral content subclasses defined in Table 4.2 are high, medium, and low frequency. The frequency ranges for these classifications are chosen to coincide with common types of power system oscillatory transient phenomena.

Table 4-2. Descriptions of oscillatory transients [23]

Oscillatory Transient	Spectral Content	Duration	Voltage Magnitude
Low Frequency	$x \leq 5$ kHz	0.3 – 50 ms	0 – 4 pu
Medium Frequency	5 kHz < $x \leq$ 500 kHz	20 µs	0 – 8 pu
High Frequency	500 kHz < $x \leq$ 5 MHz	5 µs	0 – 4 pu

4.2.6. Short Duration Variation

A short duration variation [22] is a variation of the rms value of the voltage from nominal voltage for a time greater than 0.5 cycles of the power frequency but less than or equal to 1 minute. It is usually further described using a modifier indicating the magnitude of a voltage variation (e.g., *sag*, *swell*, or *interruption*) and possibly a modifier indicating the duration of the variation (e.g., *instantaneous*, *momentary* or *temporary*).

The short duration variation is the general category of events that last for a time period that is greater than 0.5 cycles, but less than or equal to 1 minute. It is not to be confused with steady state changes in the waveform such as harmonics, notching or noise, which can have a duration within the range of a short duration variation, but typically repeat for each cycle of the sinusoidal waveform. Short duration variations are almost always caused by fault conditions, such as the energizing of large loads that require starting current that is a multiple of the operating current (motors), or conditions such as loose connections in the current carrying circuit conductors. In addition, while most short duration variations are described as voltage variations in nature, current variations can also fall into the short duration variation as well. Figure 4-5 shows the time frame of the types of short duration variations.

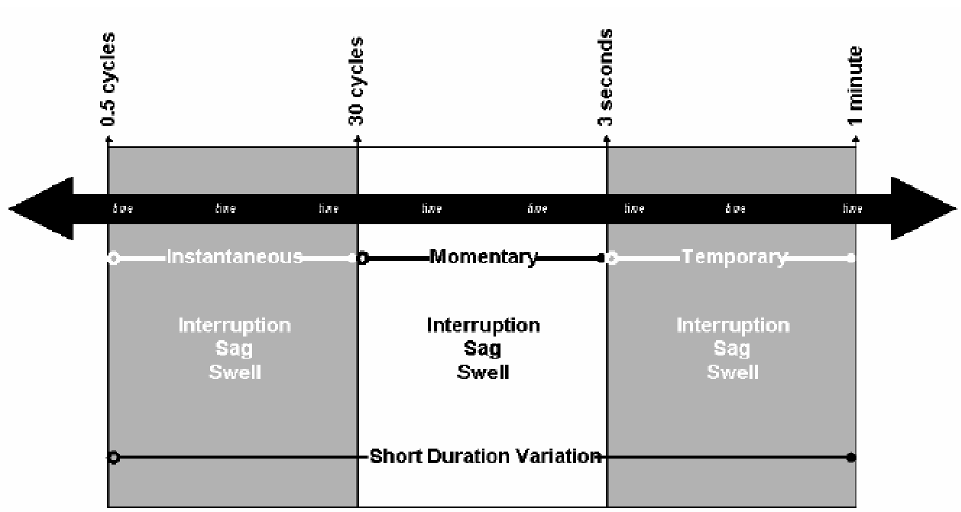


Figure 4-5. Time scale of short duration variations [23]

4.2.7. Voltage Regulation

Voltage regulation is the degree of control or stability of the rms voltage at the load. It is often specified in relation to other parameters, such as input-voltage changes, load changes, or temperature changes. [25]

Voltage regulation is calculated different ways depending on how the term is applied. As an example the voltage regulation at a customer service is often calculated in percent of nominal voltage and is:

$$\%Regulation = 100\times [Vmax-Vmin]/Vnominal$$

The above equation shows the percent change in voltage occurring relative to the nominal voltage. In some applications, it is chosen to compare the change in voltage relative to the average voltage which will yield a slightly different answer than the above formula. Regulation is also often calculated based on conditions of no load and maximum load which will yield an even greater variation.

4.3. Distributed Generation and Power Quality

A common belief among developers is that DG will improve power quality, and this potential for better quality is cited as one of the value attributes of installing distributed generators. In some cases distributed generation and storage are being promoted as an answer to the premium-quality power requirements of high technology or sensitive end-use customers. Whether or not this valuable attribute of DG is valid will depend on the specific technologies, site conditions and potential interaction with the existing electric power system.

Voltage regulation variations are defined as:

- ***Long-Duration Variations:*** Rms deviations at power frequencies for longer than one minute. [IEEE Std. 1159-1995][26]

Long-duration variations can be caused by:

- Improper voltage regulation
- Broken neutral
- Utility-initiated voltage reduction
- Sudden change of load or unusual load on a distribution circuit

Figure 4-6 shows an example of a long-duration undervoltage scenario.

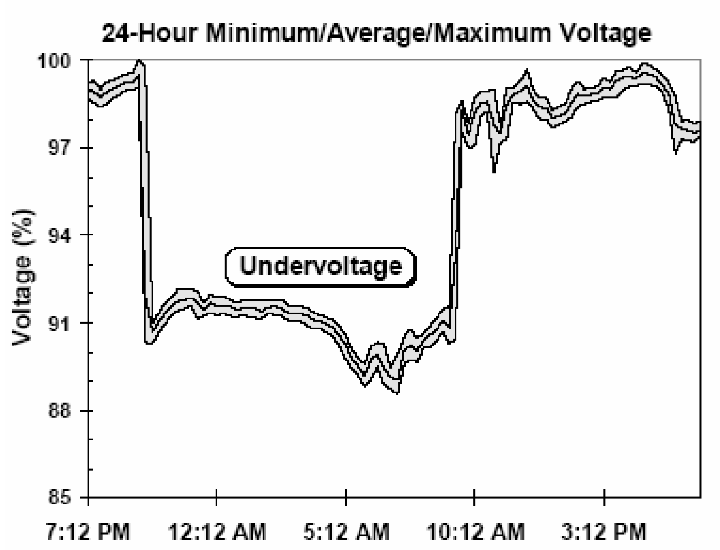


Figure 4-6. Example of a Long-Duration Undervoltage [27]

4.3.1. Regulation in Distribution Systems

Maintaining proper voltage regulation of the distribution system is a key operating objective and responsibility of the electric utility company. Voltage conditions that are out of the normal operating range can lead to poor operation of the power system and customer loads, damage to utility equipment and customer loads, and in extreme cases can even be a safety hazard.

Generally speaking, utilities strive to meet the standard European voltage limits, while realizing that some customers some of the time won't quite be in this range. On a 230-volt base, the standard requires that the service entrance voltage be between 220 volts and 240 volts. To those unfamiliar with power systems this may seem like a broad range that should easily be achievable. However, given the lengths in distribution circuits, and the significant variations in load that occur, this is not easy to achieve for all customers. It requires careful coordination and placement of voltage regulating equipment, diligence in monitoring load growth on the system and in performing periodic load flow studies to assess voltage conditions. Figure 4-7 shows a distribution of percentage range of daily voltage changes. Most undergo less than a 3% change, but a sizeable portion has swings of more then 7%.

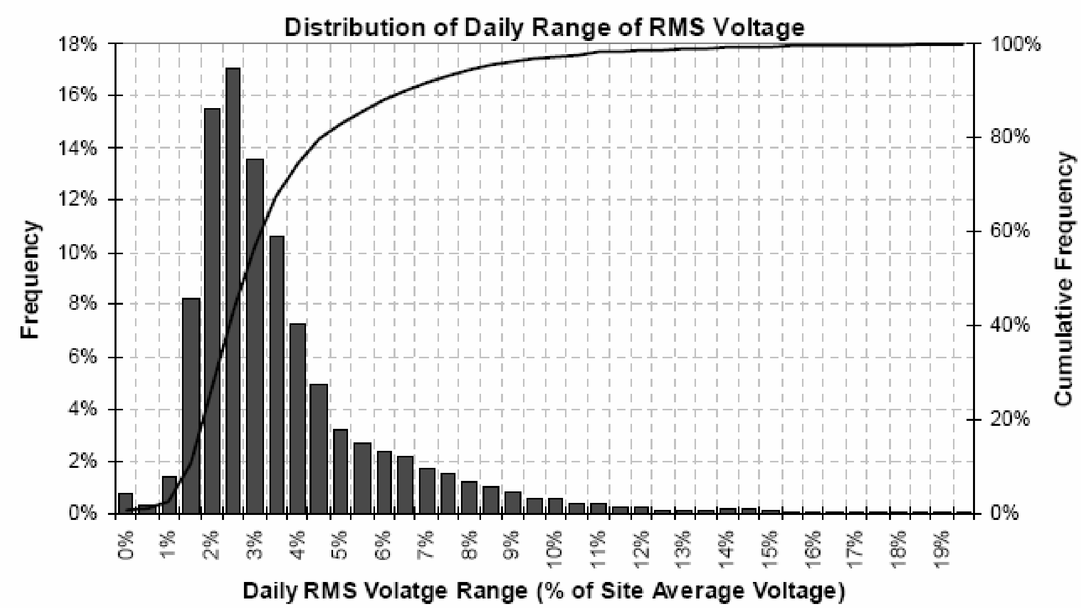


Figure 4-7. Percent Daily Change in Voltage Occurring Due to Demand Cycles on the Power System [27]

For radial power systems, voltage regulation practices are based on a single source of power (the substation) and the power taking only one path from the substation to all loads on the system. This condition leads to the assumption that the voltage will always drop on the primary feeder as the distance from the substation increases. The only exception to this assumption is when there is too much reactive compensation (a capacitor bank can causes a rise in voltage). Utilities are careful to avoid this condition, so it is reasonable to assume that the voltage drops on the primary feeder for most applications. The condition of radial flow also implies that the voltage (on a per-unit basis) will drop across each distribution transformer and secondary service (see Figure 4-8). DG introduction onto the radial distribution system will impact both of these basic assumptions used for voltage regulation.

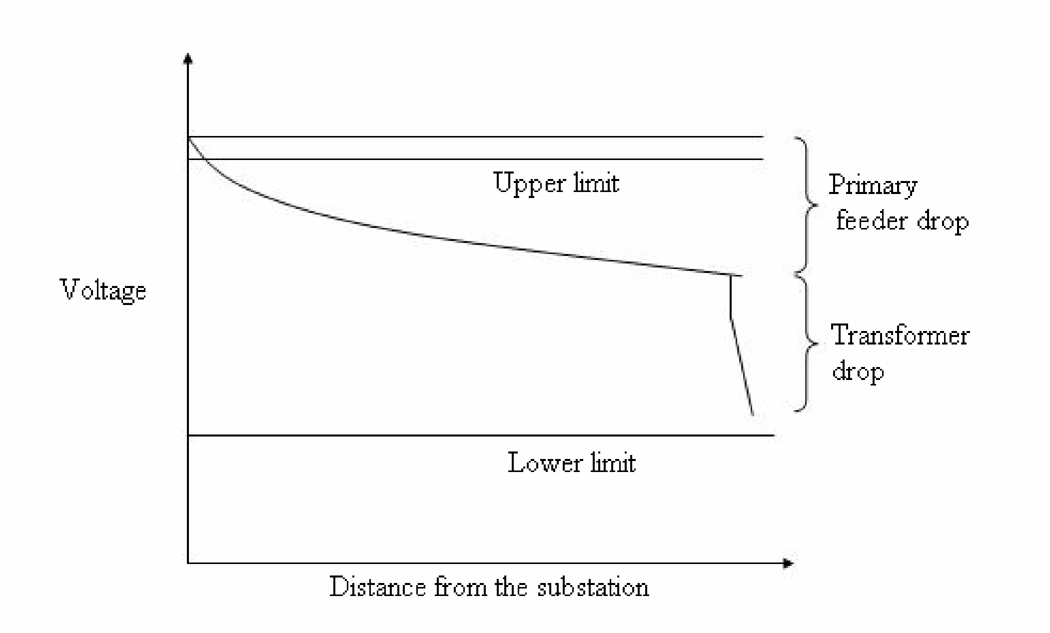


Figure 4-8. Example Voltage Profile on a Distribution Circuit

For network systems, voltage regulation is usually done entirely with load-tap changing (LTC) transformers at substations, and there is no supplementary voltage regulation equipment on the primary feeders or on the LV network side. Such equipment is not usually necessary because networks, being in an urban environment, have relatively short primary feeder lengths, and the secondary grid is very stiff electrically and tightly interconnected in a manner that allows little voltage drop. The amount of voltage drop from the substation to the service entrance of a typical network customer is far less on a per-unit basis than on a typical suburban or rural radial distribution circuit. The LTC device in the substation alone is usually enough to compensate for any voltage drops.

In general, urban networks are good examples of systems that are thermally limited – this means that as the load is increased, the transformers and cables reach their thermal limits long before voltage drop becomes a major issue. In contrast, longer radial distribution systems are usually voltage drop limited – meaning that the voltage drop becomes too excessive well before any thermal limits are reached. In general, urban low-voltage networks, since they are thermally limited, will be less sensitive than radial distribution circuits with respect to the impact of DG on voltage regulation. This means it takes a lot of injected power to significantly alter the voltage on a network. It is important to recognize that while low voltage urban networks are less sensitive with respect to DG's impact on voltage regulation that they are actually more complex to deal with and more sensitive than radial distribution systems in regards to other issues such as protection and fault coordination. This has to do with the directional relaying employed to protect network systems.

4.4. Summary of DG Impacts

DG can improve regulation or cause problems with regulation. The main ways that DG can cause regulation problems are:

- **Low voltage due to DG just downstream of a regulator with line-drop compensation**: Linedrop compensation is the technique commonly applied by LTC transformer controllers and line voltage regulators to control the voltage on the distribution system based on the line current. Under heavy load, a generator just downstream of the generator will reduce the observed load on the feeder (so the regulator will not boost the voltage as much). This leads to lower voltage downstream of the regulator.

- **High voltage due to DG:** High voltages may be caused by reverse power flow. Under light load for a location where the primary voltage is already high, the voltage rise can be enough to push the voltage above nominal limits. This can even happen for a small DG located on the secondary because of the voltage drop along the service drop, the secondary wiring, and the distribution transformer.

- **Interaction with regulating equipment:** Another area of concern is with interaction of regulation equipment and DG. If the DG has varying output, it may change the system voltage or current flows enough to cause a regulator tap change or an operation of a switched capacitor. Likewise, a distributed generator that has feedback to control voltage may interact negatively to the utility regulation equipment. There may be undesirable cycling of regulation devices and noticeable power quality impacts under such conditions.

4.5. Voltage "Following" Versus Voltage Regulating DG Units

DG is usually operated in a voltage-following mode. This means that the DG makes no intentional attempt to regulate the voltage on the power system. With this mode DG simply supplies real power at nearly constant power factor and the voltage on the feeder changes according to the effects of the DG power injection – in other words, the DG does not attempt to force a given voltage by using reactive power control. The concept of voltage following is a source of confusion within the industry since many people have incorrectly interpreted its meaning to be that DG will "follow" the existing utility system voltage and will not change the voltage on the feeder in any way. However, the basic physics of injecting power into any power system guarantee that the voltage will change as a result of current flow through the system impedance. These changes will be superimposed (add to or subtract from depending on phase angle of the injected currents) on the existing utility system voltage that is controlled by utility equipment such as LTC's and feeder regulators.

In a voltage following mode, as the real power output of the DG increases, the voltage will increase. Too much power injected into the power system can cause higher than normal voltage. If relays are set to allow the unit to continue to operate into the grid with voltage outside of normal voltage limits, then sustained overvoltage can occur. When DG is operated in a voltage-regulating mode it attempts to hold the voltage at a constant set point. Voltage regulation can be accomplished by adjusting the reactive component of the generator output either to raise or lower the voltage to offset any rise due to the real power component. This is done with rotating synchronous generators by adjusting the field excitation level. Leading reactive current (high excitation) will increase the voltage and lagging current (low excitation) will decrease the voltage. As long as the generator has sufficient capability to support the reactive and real power requirements imposed by this type of duty, it can help regulate the voltage on the power system. This type of operation, while done in some cases, is mostly avoided in grid parallel applications because it is usually not desirable to give this responsibility to independently owned generation as it requires considerable coordination with upstream equipment and the utility company. Also, many DG are too small (do not have sufficient reactive capability) to regulate the distribution system effectively.

Finally, it can be difficult to coordinate operation of the independently owned DG with utility feeder regulation devices in a suitable manner that may not severely affect the generator real power capacity. The voltage regulation mode of operation is preferred in stand-alone grid independent DG applications where the generator supplies power to the entire load and is needed to perform the voltage regulation function.

There can be considerable interaction between DG units and utility system voltage regulation equipment. Figure 4-9 shows a scenario where a DG just downstream of a regulator can cause low voltage on the end of the circuit due to the use of line-drop compensation on the regulator. The power injected by the generator will cause the regulator to not raise voltage as much as it should. To determine if the DG will cause a significant impact on the feeder voltage, the size and location of the DG, the voltage regulator settings, and impedance characteristics of the line must be considered. In the case of reverse power flow the regulator can change all the way to the lowest tap, which would cause very low voltage downstream.

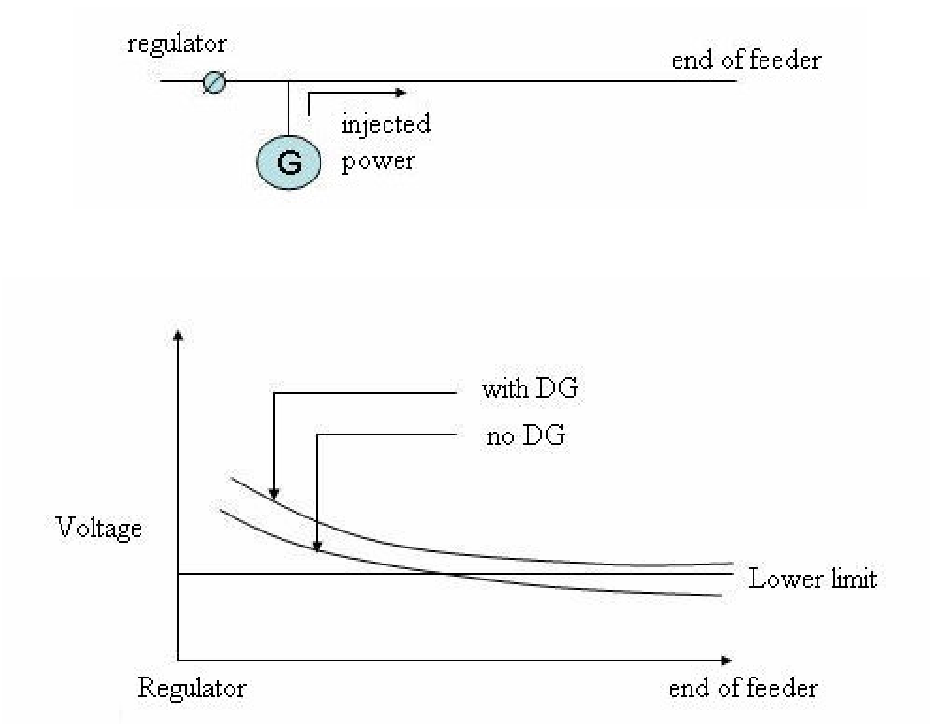


Figure 4-9. DG Just Downstream of a Regulator that Leads to Low Voltage at the End of the Feeder

A simple criterion to avoid low voltage on circuits with line-drop compensation is that there may be problems if the size of the generator exceeds 10% of the load at the regulator and the DG is located closer to the regulator than the load centre. When these conditions are met, then further study may be warranted to investigate the decrease in voltage on the feeder and determine if mitigation is required.

If problems are found, there are several options. One option for minor undervoltages is to reduce the linedrop compensator settings and raise the voltage setpoint slightly. This moves the regulator constant voltage point closer to the regulator and reduces the impact of the DG. The key is the location of the constant voltage point (also called the load centre – the fictitious point on the feeder where voltage is held constant). DG upstream of this point will lower the voltage downstream of this point, while DG downstream of the constant voltage point will support rather than lower the voltage. A more extreme option for larger DG is to remove (turn-off) the line-drop compensation on the regulator. Generally, the voltage setpoint will have to be significantly raised to provide adequate voltage on the circuit at the end of the regulation zone. If this is done, a check would have to be made to make sure high voltages don’t occur on the feeder at light load due to the higher set voltage.

If the problems are due to reverse power flow, advanced regulator controllers are available to change operating mode during reverse power flow to prevent the regulator from dropping to the lowest tap. For example, the tap change can be blocked or programmed to revert back to the neutral position if power reverses. Other options include moving either the generator or the regulator so that the regulator is downstream of the generator. Sometimes there is no way to avoid installation of new regulation equipment if the DG is especially large relative to feeder capacity.

Another consideration with regulators (and switched capacitor banks) is unwanted interaction with DG (especially fluctuating sources). The main way to avoid this is by widening the regulator bandwidth setting and, in some situations, reducing line drop compensation settings. Increasing the time delay can also help prevent excessive regulator tap changes depending on the rate of change of the DG energy source. Wind and photovoltaic energy sources that impact the feeder load by 10% or more at voltage regulators or switched capacitors are the most likely causes of these types of interactions. Wind and PV energy sources experience wide fluctuations in output on a repeating basis due to partial cloud cover or wind variations. These fluctuations may occur over many seconds or minutes depending on conditions.

4.6. DG-Caused High Voltages

There are also concerns with DG causing high voltages on distribution circuits because of reverse power flow. It is possible to estimate the effect of a generator by using the standard voltage drop equations with reverse power flow. The voltage drop along a feeder due to a load is approximately equal to:

$$Vdrop = I_R R + I_X X$$

Where:

Vdrop= voltage drop along the feeder

R = line resistance, ohms

X = line reactance, ohms

I_R = line current due to real power flow, amps (negative for a generator injecting power)

I_X = line current due to reactive power flow, amps (negative for a capacitor)

The voltage at the generator can be estimated by taking the highest prefault voltage and adding the voltage rise due to the generator from the equation above. Note that this approximation is no substitute for a proper load flow. It does not fully model the response of the load to the change in voltage, and it does not consider regulator response. It is useful for a first attempt at estimating whether the voltage rise due to the generator might be a problem.

The DG which is exporting mainly real power will cause voltage to go up most where X/R ratios are low. The real power portion will cause the largest voltage rise when the line resistance is high. If the DG is injecting reactive power like a capacitor or there are fixed capacitors nearby, the voltage rise is even larger. Under the right circumstances, this voltage rise is beneficial (voltage support), but if too much rise occurs or it occurs on a section of feeder where the voltage was already near the upper normal limit before the DG started, then a high voltage problem may be created (see Figure 4-10). If voltage rise can be a problem, there are several options. One would be to limit the size of the generator to below the level necessary to cause problems. Another would be to relocate the DG to a more suitable location on the distribution circuit.

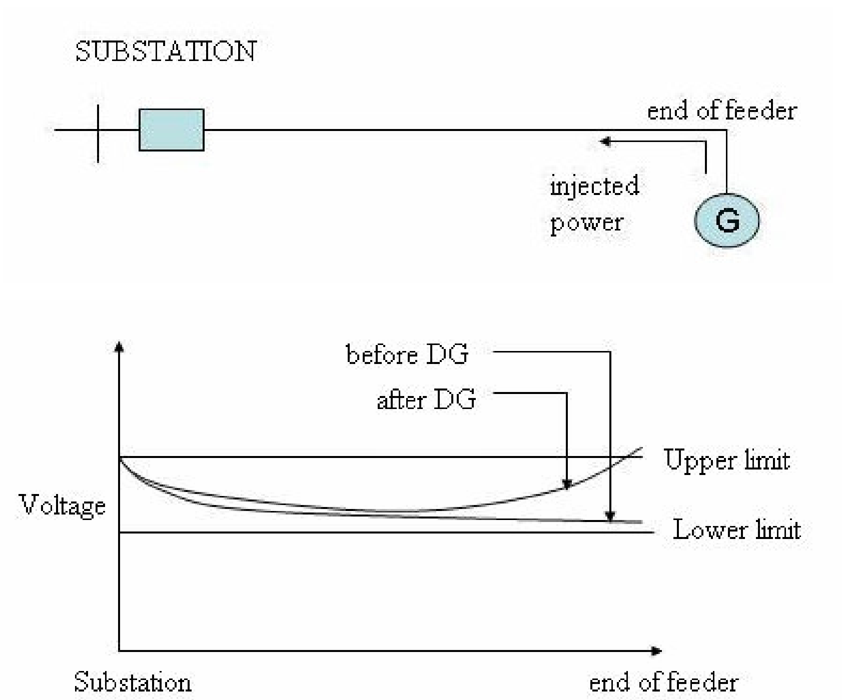


Figure 4-10. Voltage profile on feeder before and after addition of large DG. High voltage may occur at the end due to the voltage rise caused by the DG injected power

On the DG side, the generator could be operated to absorb more reactive power (by removing local capacitors or operating a synchronous generator). This is the opposite of what is normally done and reduces the T&D support value of DG. Reducing the power factor of the generator causes voltage drop due to the reactive component of the generator. This approach may increase losses on the feeder, however, and result in an effective reduction in available capacity on the feeder.

A utility company option would be to reduce the resistance of the lines and transformers from the substation bus to the DG site – a costly scenario (see chapter 5). This would be done by using larger conductors on lines and cables and specifying lower copper losses on transformers. Another utility-side option is to add regulation equipment (capacitors or regulators) to oppose to the voltage rise from the distributed generator. Of course, the least costly utility option could be reducing the voltage level setting on the existing regulation equipment without risking low voltage on the feeder during periods when the DG is off and/or there is heavy load. [27] [29] [30] [31]

5. Voltage Control with DG

The voltage (V) at the remote end of a feeder is determined by the source voltage (E) and the voltage difference (+ve or –ve) along that feeder. This voltage difference (ΔV) along a feeder is influenced by various factors, these being:

- The line resistance, R
- The line reactance, X
- The reactive power flow, Q
- The real power flow, P

This results in the typical voltage drop equation [28]:

$$E - V = \frac{PR + QX}{V}$$

Therefore, network voltages can be managed in “planning” timescales by altering R and X or in “operational” timescales by controlling P and Q. It is interesting to note that if the generator is exporting real power (P), at the same time that it is importing reactive power (Q), the voltage change can be minimised. This is especially true in networks which have a large X/R ratio (i.e. overhead line networks).

5.1. Solutions to Voltage Control Problems

5.1.1. Line Re-conductoring

Re-conductoring a circuit with a lower resistance cable or overhead line improves the voltage regulation along that circuit. This improvement is a direct result of the lower network resistance, and therefore increases the amount of distributed generation which can be connected. Such a solution, however, clearly has associated costs.

Line re-conductoring could be carried out at a time of scheduled asset replacement, where the marginal cost of using higher rated cables or lines may not be so great. Also, new networks have the option of using different design criteria, such as incorporating network designs with shorter cable lengths (but more, smaller transformers). Such an approach needs further study to quantify the costs and benefits and to optimize the design. The cost framework (i.e. regulatory incentives) would also need to be examined.

This solution can lead to a reduction in customer interruptions and connection interruptions, as a result of an increase of the availability of the connections and network capacity. Voltage profiles on the circuit can be improved, resulting improved power quality and lower losses. It is a "benchmark" solution and one of the key issues for implementing such a solution is the cost, and these are different for the different voltage levels.

Line re-conductoring is a solution that can be readily adopted in the short term, but the introduction of new network design philosophies could and should be considered in the longer term perspective. These philosophies include:

i) Increasing the extent of the higher voltage networks, combined with the use of more, smaller, transformation nodes.

ii) Extending the extent of voltage control within networks, possibly as far as the LV network.

5.1.2. Build a Dedicated Line or Network

Building a dedicated line or network for the connection of generation is effectively separating load customers from generation customers. This approach has merits under certain circumstances, for example, when the load density is low relative to the local distributed generation resource. The advantage of this arrangement is that normal load customers are not subject to the voltage conditions arising from generation. This approach enables the Distribution Network Operator (DNO) to agree voltage limits outside statutory limits with the generator. These networks may be particularly applicable in rural networks with few load customers, but many potential generation customers in the form of windfarms, small-scale hydro and biomass generation schemes.

Since the network would be designed specifically for the needs of the distributed generation, this solution should provide the minimum barrier in terms of technical difficulty, but it can be an expensive option unless all the network capacity is utilised. The solution leads to a significant reduction in network capacity constraints due to the physical increase in local network capacity.

The network would be implemented as dedicated lines to the distributed generation and the impact on customers would be negligible. The cost of building a dedicated line may be high. However, considering the additional connected capacity achievable, and otherwise higher levels of interruptions, generator connection costs could be justified for concentrated resources.

The difference between the generation capacity and adjacent demand will determine whether there is any significant change to the voltage profiles upstream. The substation voltage control will be affected if the generator export causes reverse power flow. On the other hand, environmental aspects and requirements for planning consent may have implications for this solution.

This is also a "benchmark" solution. The building of a dedicated line or network for the connection of generation has been used with some success in Germany. The option of introducing additional capacity by installing a dedicated line or network is one clearly within the present "Toolbox", and could be construed a relatively simple to implement. As outlined with the previous solution, one of the key issues in its implementation is that of cost.

5.1.3. Generator Reactive Power Control

Reactive power control is a technique commonly used in transmission networks to maintain voltage profiles along a line. Generally speaking, transmission lines tend to be longer than distribution lines and their X/R ratio higher. This means that reactive power control is not so effective within distribution networks, but nevertheless can provide some benefits. Presently, however, it is normal practice for DNOs to require distributed generators to operate at (or close to) unity power factor since this has a governing influence on the reactive power.

Reactive power control for conventional generation can be at the distributed generator, or at the connection point of several distributed generators to the network. Switched capacitor & reactor banks or transformer tap changers can be used, giving a wide range of options.

A practical example might be a windfarm with asynchronous generators. These would normally require power factor correction capacitors to be fitted to provide for generator starting. The capacitors would remain connected to allow the windfarm to operate close to unity power factor. However, if the capacitors were switched out after the windfarm had started, then the windfarm would import reactive power, helping to maintain a flatter voltage profile on the network. However, this could also give rise to a poor power factor condition on the remainder of the network and hence voltage control problems. Obviously, system studies would be required in any particular case to assess the possibility, but it is a very cost-effective solution when it can be applied. Increased reactive power flow also influences the network loading and could reduce the network capacity available.

The solution is dependent on the generation technology. For synchronous machines the reactive power control is achieved by excitation control, for asynchronous generators the control is through capacitor switching and for doubly fed induction generators (DFIG) machines the power factor and voltage control is provided by the DFIG's ac/dc & dc/ac converters and controller. The control is limited by the reactive power capacity for the generation technologies. The control is limited by the reactive power capacity for the generation technologies.

The solution results in a reduction in generation constraint, though the reduction depends on the reactive power capacity and the generator size. The generator connection costs relative to the additional connected capacity achieved for small to medium generators can be reduced. For higher capacity generators, the effectiveness of the solution is limited.

On the other hand this solution may trigger generator ongoing additional operational costs in operating their installation with the implemented solution. It may also result in more reactive power flow, which is constrained by the operational regulations put in place by the network operator. There are also commercial implications in terms of reactive power charging.

As far as DNOs are concerned the solution will change the voltage profile on circuits. It may require a review of voltage control systems as the solution changes the PF (Power Factor) of the feeder, which may cause problems for On-Line Tap Changer (OLTC) control. An increase in network losses can also result because of the resulting poor power factor. The solution may have implications on the performance of existing and future network assets in accommodating higher reactive power levels within the network.

Other practices of reactive power control to increase a wind farm's capacity, without reinforcing the connection, are also being implemented. With the correct reduction in power factor, and validation against load duration curves for the load centres, operating a generator at a reduced power factor reduces the chances of an excessive voltage at other customers' connections. Reactive power import however may be a significant chargeable cost to a project and so would need to be considered.

5.1.4. Generator Real Power Control

Control of the generator power output can be a way of enabling more generation to be connected and increasing the overall financial performance of a development. If the level and frequency of generator curtailment is relatively small, then this can be a very attractive solution. In principle, real power control could be carried out in "real time", although it could also be achieved more easily using a simple seasonal control.

Consideration would have to be given to the market implications of constraining energy. Constraining the outputs of more than one local generator adds both flexibility and complexity. For example, the management of distributed generators competing for available network capacity adds complexity, but the available options (i.e. which generator to curtail, to what extent and when) adds flexibility. Therefore, the control of a single generator is a short term solution, whilst the control of multiple distributed generators is likely to require further consideration.

The constraining of energy output would affect the economics of the generation site. This solution is dependent on the generation technology. For synchronous generators control can be achieved through the prime mover. In the case of fixed speed wind generators, it can be done through pitch control. For doubly fed wind generators, real power output can be adjusted in a certain range of control by electronic control. There is a need to monitor the voltage in order to issue the control when necessary.

There may be a reduction in the availability depending on the size of generator. The solution reduces the connection costs relative to the additional connected capacity achievable. The solution triggers the generator's ongoing additional operational costs in operating their installation with the implemented solution. Changes to generator equipment are required for some generation technologies in order to monitor the voltage and carry out real power control. As energy storage becomes more of a viable option, the solution would become more attractive.

Overvoltages can be prevented by generator real power control or generation constraint. No schemes currently in operation have been identified, although several wind farms are being developed with real power control, with the generator effectively being offered a shallow connection. The constraint mechanism has not yet been defined in these examples, but is likely to be simple in technical implementation (i.e. simple on/off control). [29] [30] [18] [31] [32]

6. Case Study: Pilot Installation in Stutensee, Germany

The case study of the project involves a typical residential site in Germany with DG containing CHP, PV and energy storage.

The site is called "Settlement Stutensee" and has the following characteristics:

- It is a residential area with 101 residential units.
- The LV grid is owned by MVV Energie and is fed from the EnBW MV-grid via a transformer.
- The LV voltage is 230 V (phase to neutral voltage) / 400 V (phase to phase voltage). The MV voltage is 20 kV.
- The LV grid is a three-phase network with distributed neutral. The LV neutral is directly grounded at the MV/LV substation.
- The loads are connected with underground cables (main: Aluminium (Al) 4x150mm^2, lateral: Al 4x50mm^2) via 6 distribution boxes. An additional distribution box is used to connect the PV plant and battery through a 100m long Copper (Cu) 4x10mm^2 cable. The LV network has a ring structure, as shown below.
- A 40 kW CHP plant is installed (operated by MVV).
- A 28.8 kW PV plant is installed (operated by a private person). It is assumed that further PV plants will be constructed in the near future.
- An 80 kWh battery connected via an inverter of 100 kVA is installed (operated by MVV).

An overview of the Stutensee site is shown in figure 6-1.

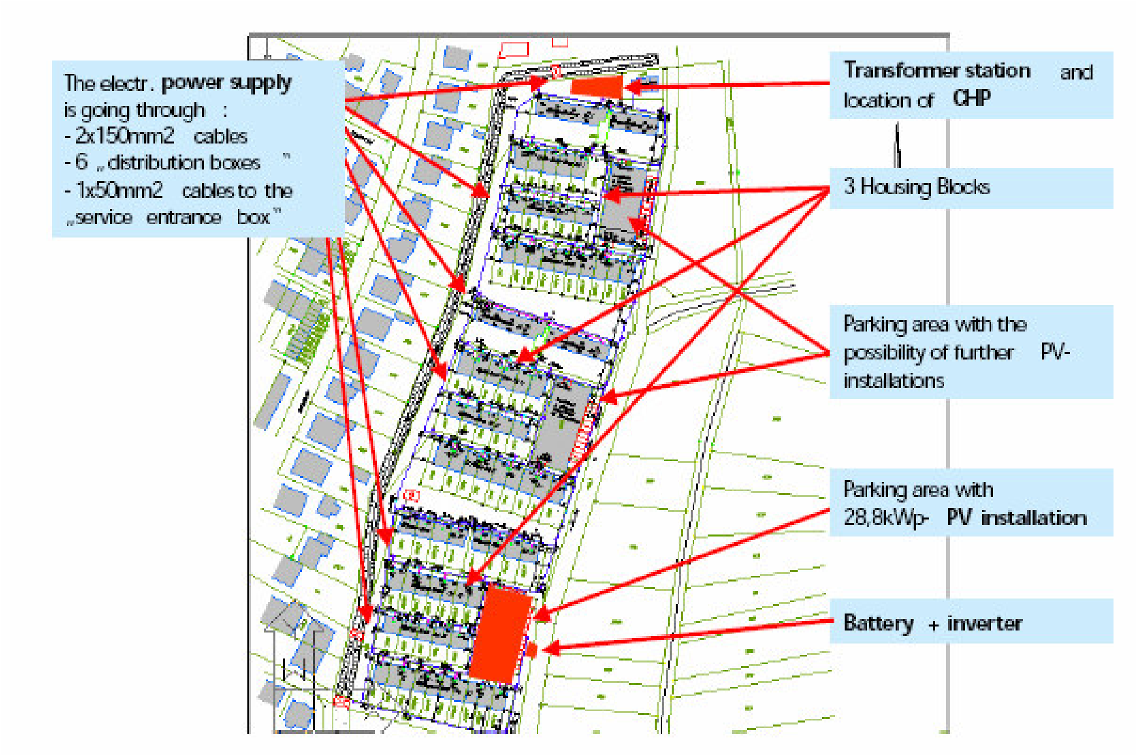


Figure 6-1. Overview of the site [32]

For the purpose of testing and to demonstrate the effects of PV on power quality, an unusual means of connection will be used to reduce the short circuit power at the PV connection point. A distribution box will be inserted in the loop between distribution boxes four and five. The PV and battery will be connected to this distribution box via a 100m long Cu cable with 4x10mm^2 cores. This relatively long, high impedance cable reduces the short circuit level at the terminals of the PV and battery to approximately 0.67MVA. This will be referred to as connection case (b).

If connected with a normal lateral cable to the closest connection point (in the loop between distribution boxes five and six), the short circuit level at the terminals of the PV and battery is approximately 3.4MVA. This configuration will be referred to as connection case (a).

Ten rows each with eighteen PV modules are positioned on the flat roof of a parking garage. Within Settlement Stutensee there are two more parking garages of the same type. If more investors were found, these would be the best locations to build similar, cost-efficient PV installations.

The networks layout is presented in figure 6-2.

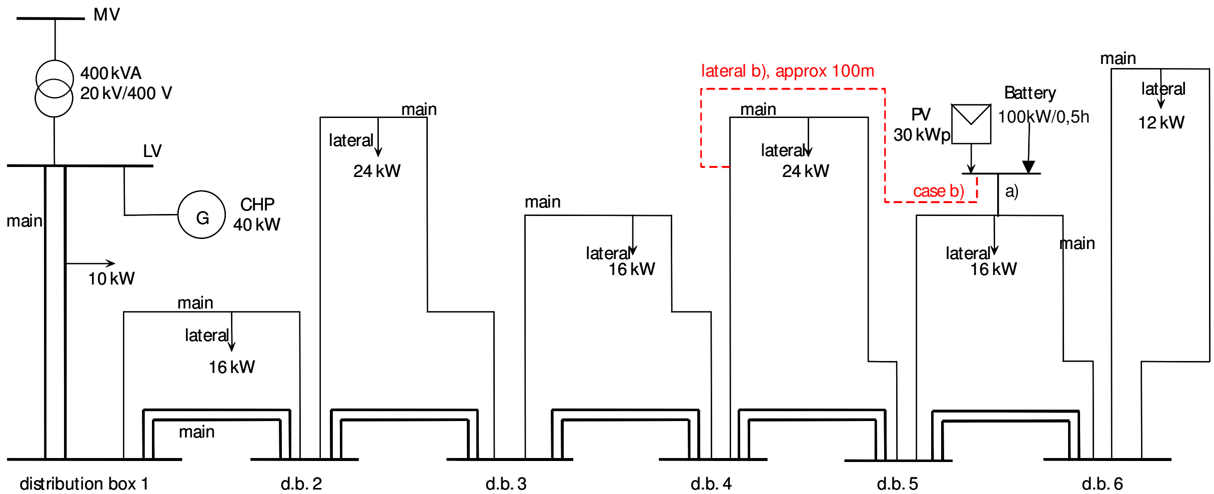


Figure 6-2. LV network layout [32]

The controllable devices in the Stutensee grid are described below:

CHP

Summary Information

Type:	Kuntschar und Schluter GTK 40
Manufactured:	November 2000
Prime mover:	4 cylinders, gas motor
Generator:	3 phase AC synchronous generator, self-exciting, self-regulating
Generator rating:	65kVA, 40kW
Power factor:	0.8 inductive to 1
P thermal:	67kW
P electrical:	40kW
Rated voltage:	400V
Rated current:	80A
Max current:	2.5 to 3 times rated current for 5 seconds
Rated frequency:	50Hz
Speed:	1500 rpm
Generator efficiency:	93.20%
Overall electrical efficiency:	33%
Overall thermal efficiency:	54%

PV

Summary Information

PV Type:	Sunways/Konstanz SOLON P160/5 poly-crystalline solar cell
PV Capacity:	28.8 kWp (180 modules)
Inverter Type:	Sunways/Konstanz NT6000 DC-AC-inverter
Inverter Rating:	30kVA (5 inverters) in total, comprised of: • 2x 6kVA on phase 1 • 2x 6kVA on phase 2 • 1x 6kVA on phase 3

Battery

Summary Information

Manufacturer	Gustav Klein GmbH&CoKG, 86956 Schongau
Battery Type:	Lead acid
Battery Capacity:	80kWh
Battery Efficiency:	93% (charge and discharge)
Inverter Rating:	100kVA in both directions (4 quadrant operation)
Inverter Efficiency:	90% (charge and discharge)

Simulation Software

The initial studies for the case study network were contacted by using the PSS/E simulation software.

PSS/E identifies the network by the following data:

- General information
- Bus Data
- Load Data
- Generator Data
- Branch Data
- Transformer Adjustment Data
- Other…

An example network diagram in PSS/E is shown in figure 6-3.

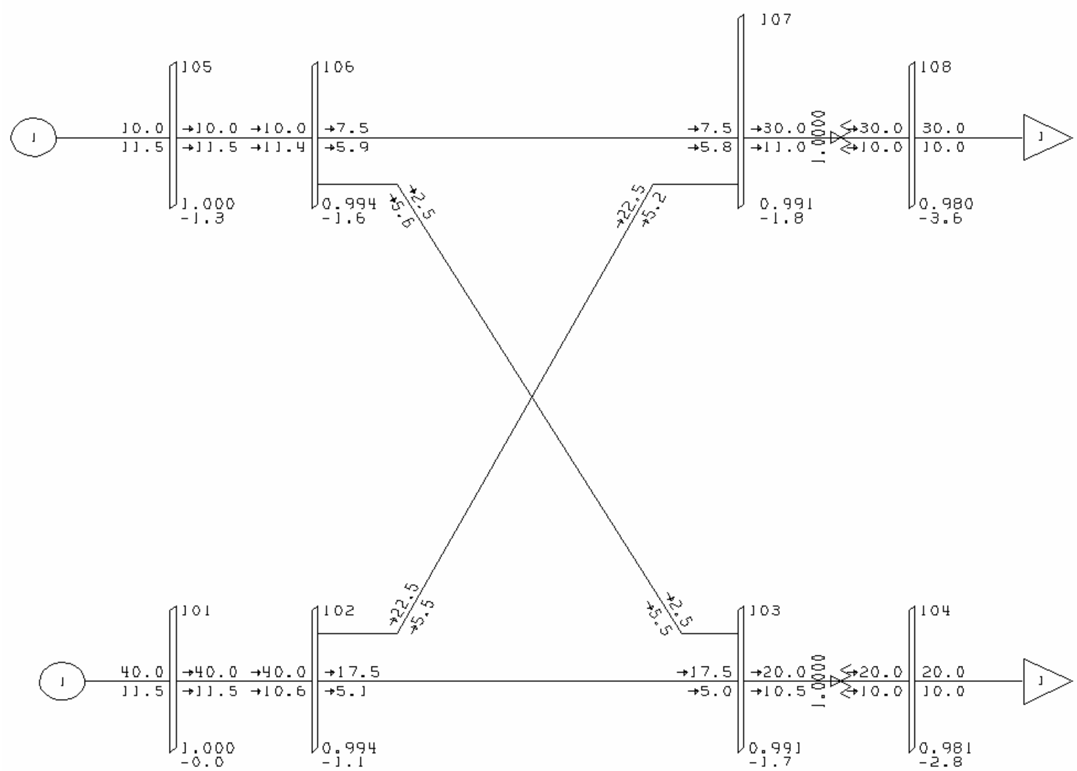


Figure 6-3. Example PSSE/ network diagram

The steady-state network solution determines:

- Power flows
- Bus voltages and angles
- Generator outputs
- Transformer settings

The program through an iterative solution works out the above values so that there is a minimum mismatch. The following studies are focused on the voltage control offered by DG and PSS/E data were used in order to extract voltage profiles of the network for different operating conditions.

Assumptions for the simulations:

Before presentation of the simulation results associated with this set of case studies special mention must be made of the voltage limits within Germany. The UK has historically used a single phase to neutral voltage of 240V with upper and lower limits of ±6% permitted. The rest of Europe has typically used a single phase to neutral voltage of 220V also with limits of ±6% permitted. As a result of this difference in the following studies the single phase to neutral voltage in the Stutensee network will be considered 220V with an upper limit of +10% and a lower limit of -6%.

The simulations are focused on detecting the network's marginal operating conditions in order to ensure its operation within the nominal voltage limits.

Initially the studies are carried out in normal grid voltage conditions with the network loads and the DG output varying from zero to maximum.

These studies are followed by over and under voltage studies in order to determine if DG can contribute in improving the network's voltage profile in such conditions.

Also, the following expressions will imply:
Full DG: Full output from the CHP (40kW) and PV (28.8kW)
No DG: Zero output from CHP and PV
Any output from the battery will be separately mentioned.

Max Load = 117.77 kW – The peak load of the network
Min Load = 117.77/6 kW = 19.6 kW – minimum load of the network

6.1. Case b

The initial simulation studies of the case study network where on "case b", the one where the PVs and the battery are connected to the network via a long, high impedance cable. Case b was tested first because it was a testing configuration. The bus on which the PVs and the battery are connected is the last in the network configuration. Here are some of the results for case b:

Starting point: The CHP and PVs are off and the battery output is zero. The following graph shows the network's voltage profile with no DG for maximum and minimum load.

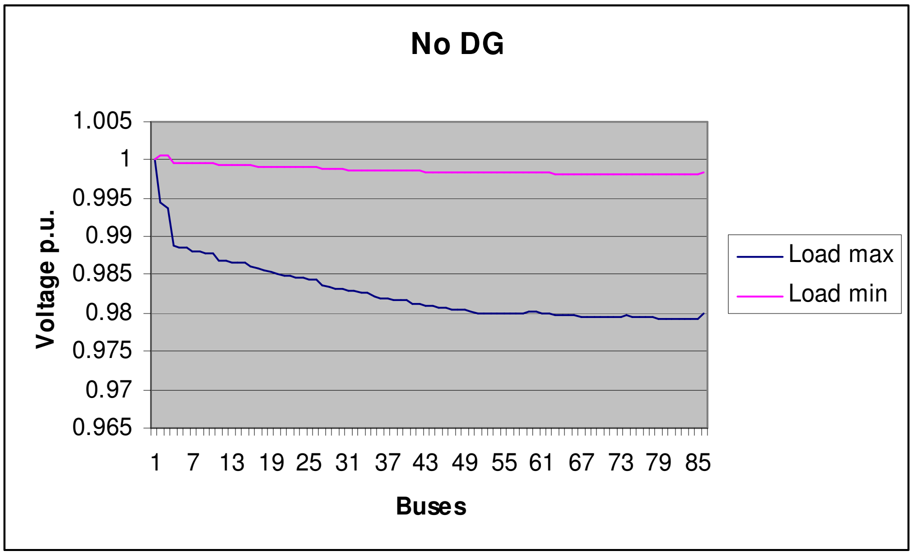


Figure 6-4. Starting point voltage profiles

In both cases the voltages are in nominal levels.

The next step is to consider full DG output. The profiles are in the next figure:

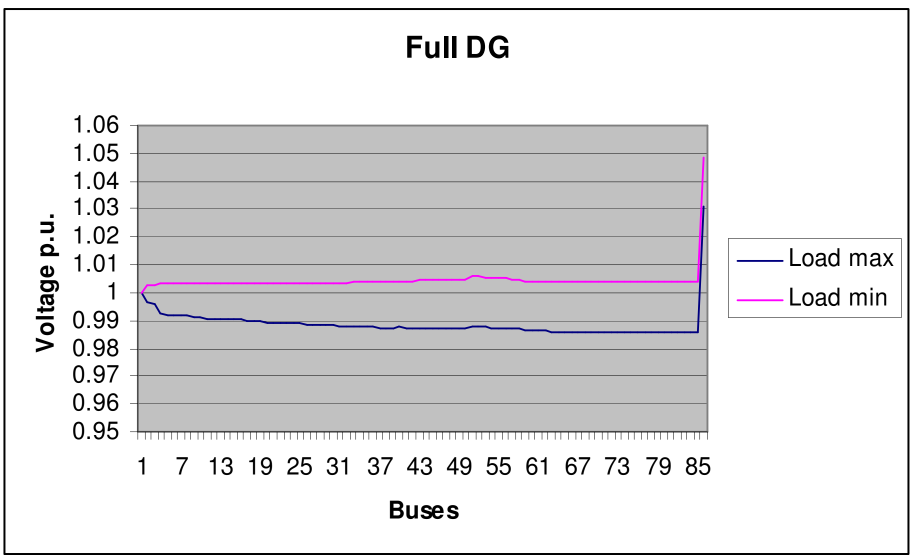


Figure 6-5. Voltage profiles for full DG

The PV output causes a voltage rise in the last bus (where PVs and the battery are connected). The voltages are still in nominal levels. If we consider full output from the DG and maximum output (100kW) from the battery the overvoltage in the PV and battery bus is in not acceptable levels (fig.6-6).

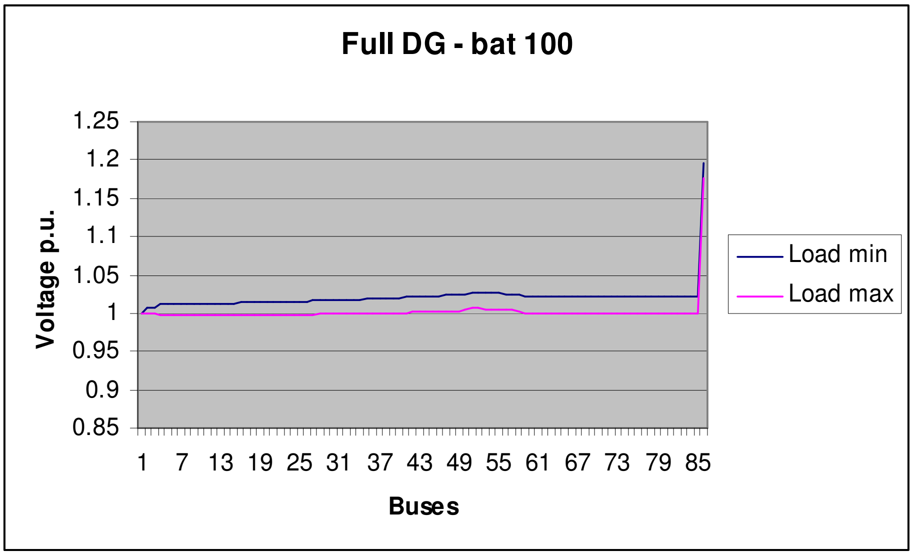


Figure 6-6. Voltage profiles for full DG and full battery output

There are also problems when the battery is operated as a load. Figure 6-7 shows the profile when the battery absorbs 100kW with zero output from the CHP and the PVs.

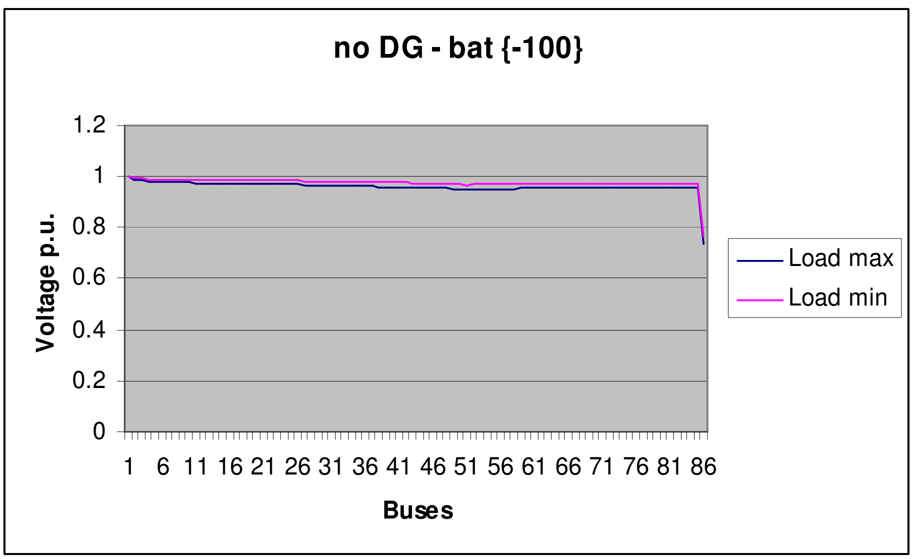


Figure 6-7. Voltage profiles for no DG and battery absorbing full power

The not acceptable undervoltages in the last bus are obvious. As we can see from the voltage profiles exported that the case (b) configuration causes problems of over and under voltages in the bus on which the PVs and the battery are connected. More scenarios were investigated with similar results. The rest of the studies are focused on case (a).

6.2. Case a

Starting point: This study assumes again that all DG is zero and the system is running on minimum and full load (fig.6-8).

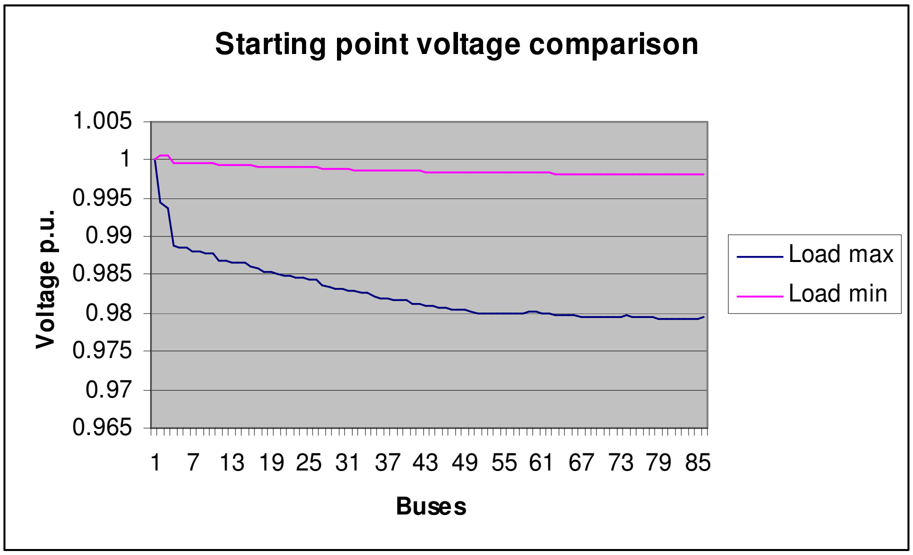


Figure 6-8. Starting point voltage profiles

There is a logical voltage drop in the full load situation but all the bus voltages have acceptable values. With full output from DG the profiles are the following (fig.6-9):

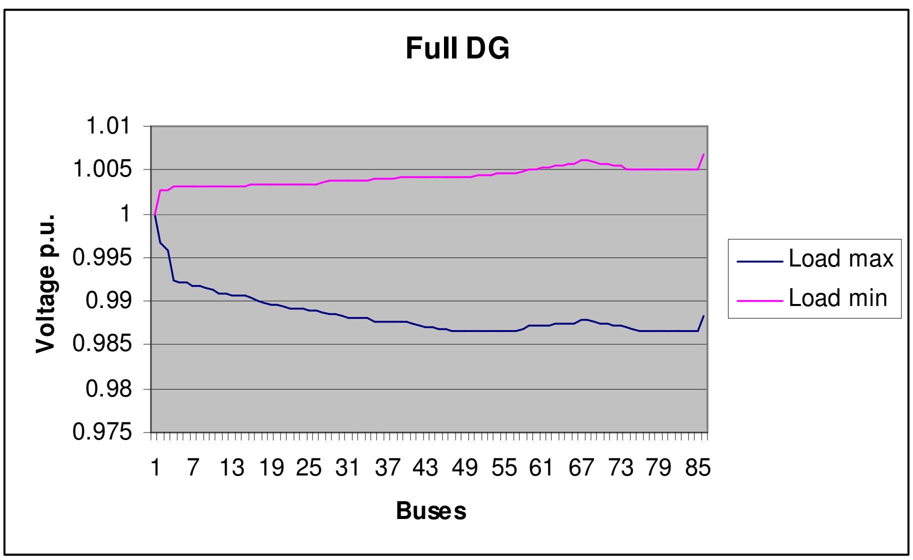


Figure 6-9. Voltage profiles with full DG

The voltages are in nominal levels and there is no overvoltage in the PV and battery bus.

This configuration performs very well even in extreme conditions like:

- No DG , maximum load and battery absorbing 100kW (fig.6-10)

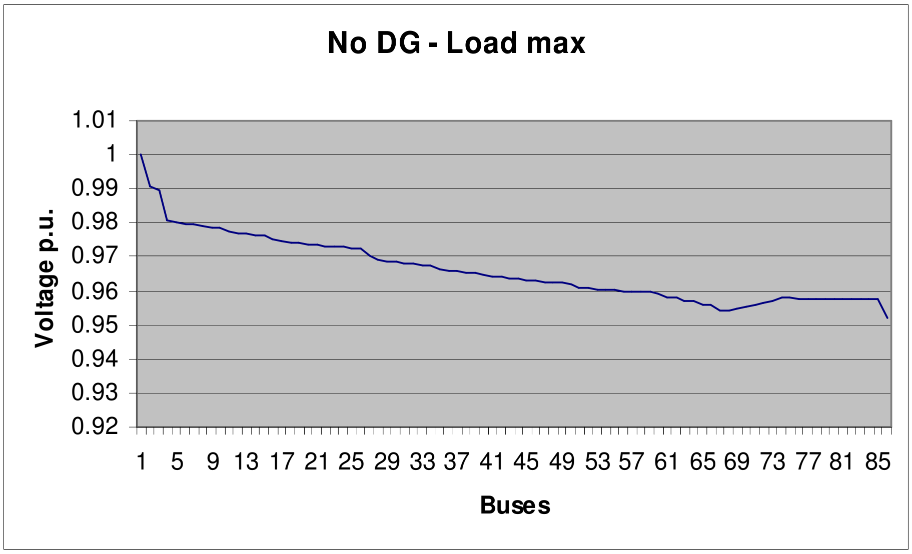


Figure 6-10. Voltage profile for no DG, full load and battery absorbing full power

The voltages are always in the -6% nominal range

- Full DG, minimum load and battery producing 100kW(fig.6-11)

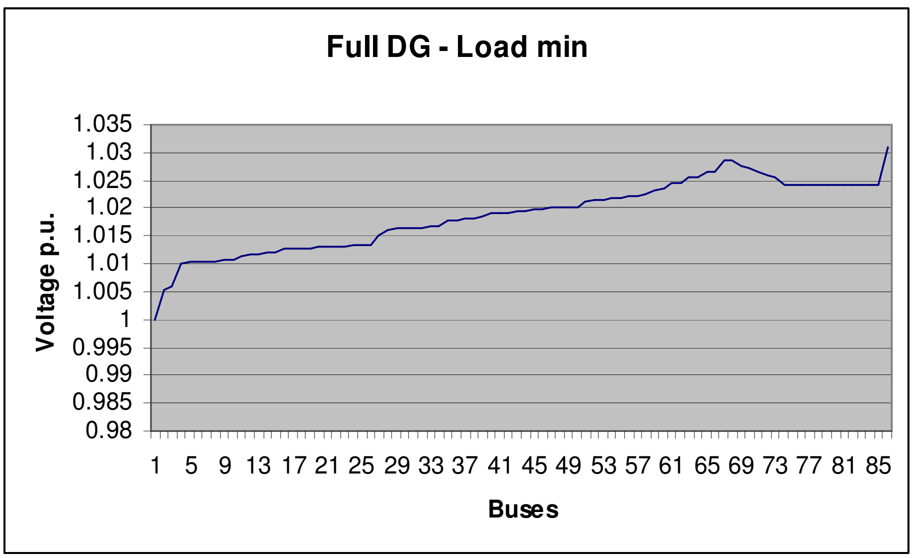


Figure 6-11. Voltage profile for full DG, minimum load and battery producing full power

The voltages are always in the nominal +10% range.

No possible operating DG options can get the network's voltages out of the nominal levels in normal operating conditions.

6.2.1. Undervoltage Studies

10% drop

Grid voltage is pulled down to 0.9p.u. The options of min and max load are considered (fig.6-12).

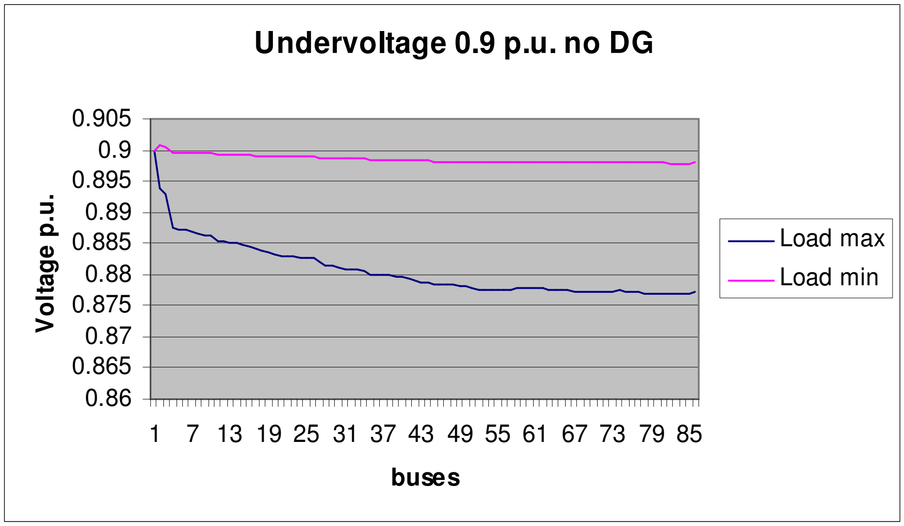


Figure 6-12. Voltage profile for no DG output

It is obvious that a 10% undervoltage drops the network voltages to non-acceptable levels even with minimum load.

The next step is to assume full output from the CHP and PV units and also consider cases of full battery output (fig.6-13).

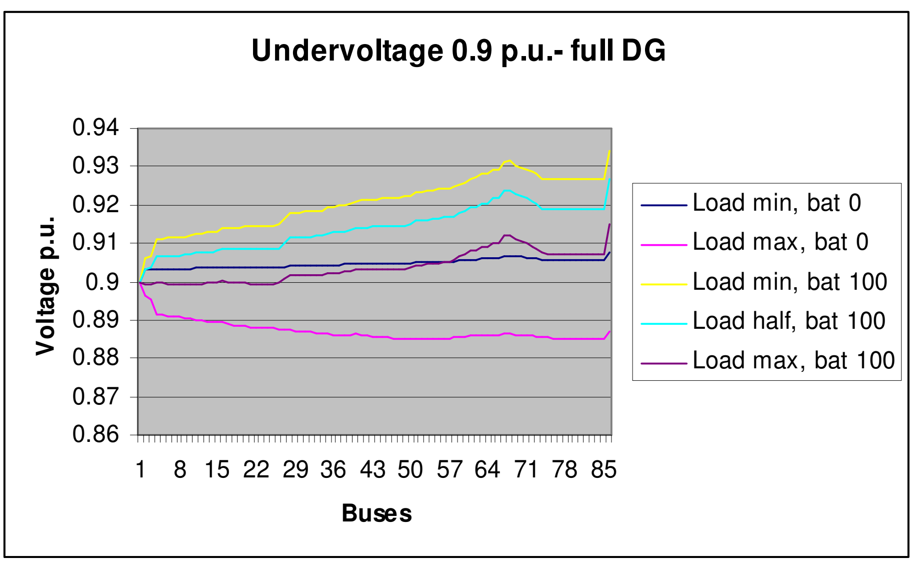


Figure 6-13. Voltage profile for full DG output and different load and battery states

With the CHP and the PV in full power output there is an improvement in the voltage profiles especially when the load is low. By adding full battery output the voltages are raised even more. Still the system cannot reach the -6% limit on a 10% undervoltage, but DG operation makes a voltage regulation improvement.

5% drop

In this case a smaller drop of 5% is assumed with the same DG operation. The first study assumes no DG (fig.6-14):

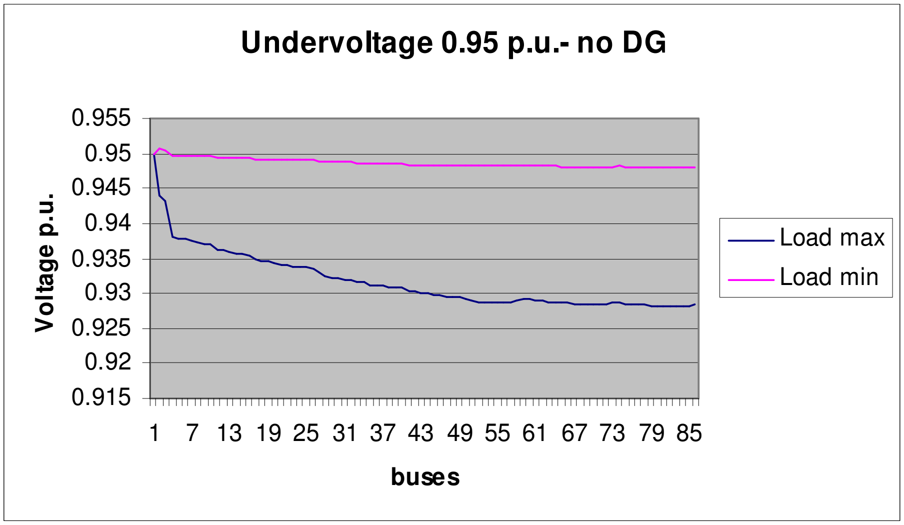


Figure 6-14. Voltage profile for no DG

On a 5% undervoltage with no DG there is a problem when the load is high.

The voltage profiles for various DG, load and battery states are shown on figure 6-15.

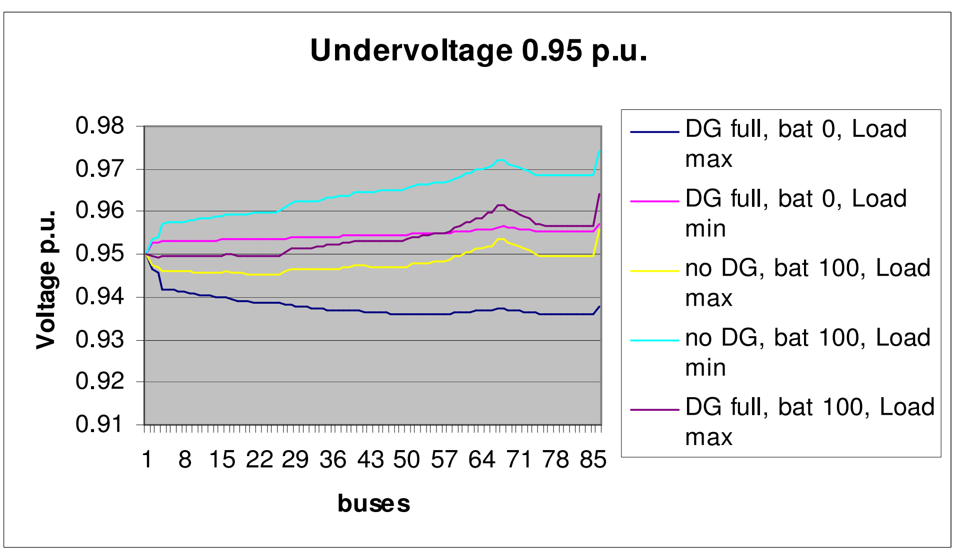


Figure 6-15. Voltage profile for different DG, loads, and battery outputs

With full output from the CHP and PV full load causes more than -6% undervoltages. With full output from the battery problems are solved even with full load and no DG output.

This study shows how powerful the battery operation can be. When it is fully charged it has the potential to regulate a 5% voltage drop on a full load situation even with no help from the CHP or the PVs.

6.2.2. Overvoltage Studies

This study assumes a 10% voltage rise which is the upper margin for a 220V network. Grid voltage is pulled up to 1.1 p.u.

The first case is that the overvoltage happens with no DG in operation. The buses voltage profiles in this case are shown in figure 6-16.

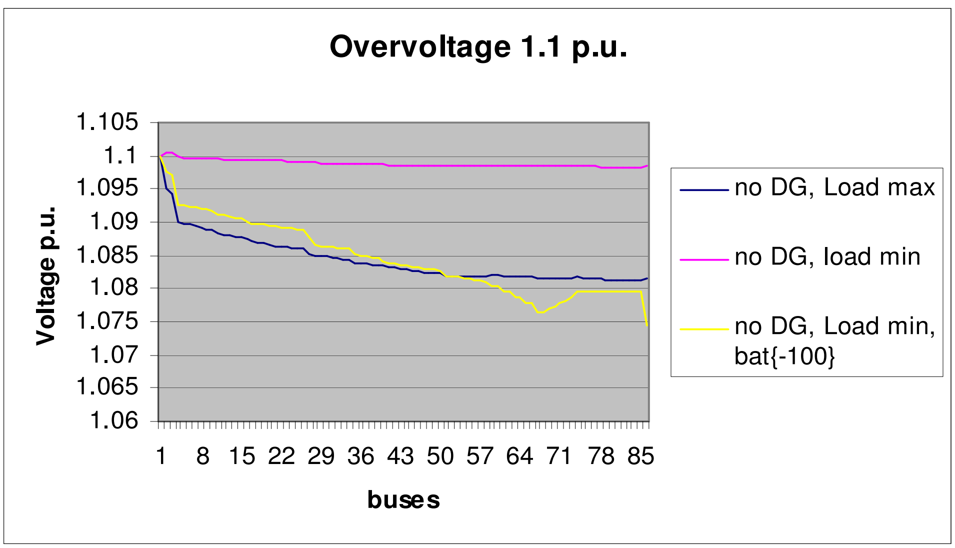


Figure 6-16. Voltage profiles for no DG output

The voltages are in acceptable levels. When the load is small the battery provides good help if adjusted to operate as a load and absorb 100KW.

The worst case scenario here would be an overvoltage occurring when DG is operated in full mode. The profiles in this case are shown in figure 6-17.

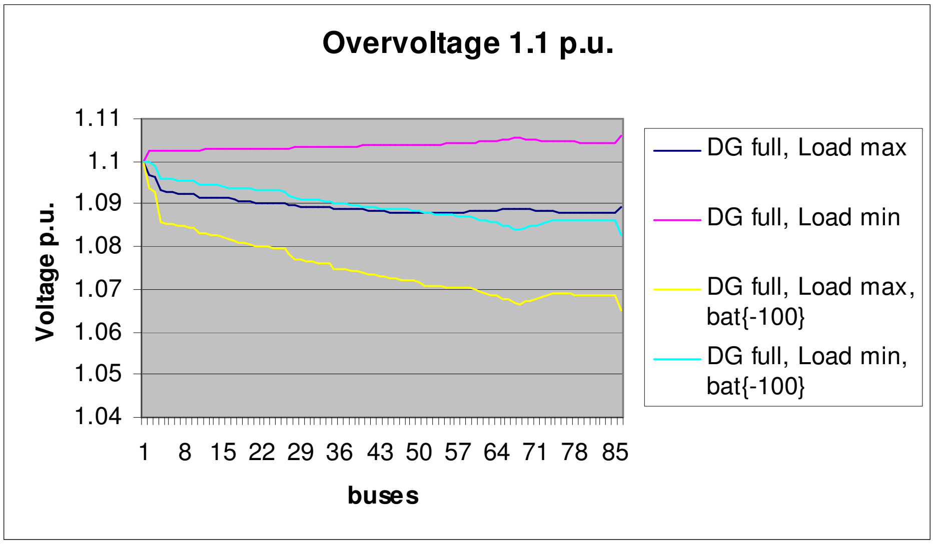


Figure 6-17. Voltage profiles for full DG output

Voltages rise above the required 10% in this case on low load situations. With the battery absorbing 100KW the voltages can drop to nominal levels. On high load conditions the voltages are always acceptable but the battery can still make a positive impact.

6.3. Conclusions – Operating strategies

The results show that the MVV network is rather a "strong" network. The limits of nominal voltage conditions are very close to the +10%, -6% voltage variation.

It is obvious from the above studies that DG operation can have an impact on voltage regulation and power quality generally. The most controllable component of the network's DG is of course the battery.

6.3.1. Peak-shaving

In this application the battery is used to provide peaking power. Fig.6-18 shows an average winter demand profile and fig.6-19 an average summer day demand profile. Assuming that the CHP unit is in constant operation in winter, there is some excess power in early morning hours. This power is used to charge the battery and this power is later provided in the "high demand hours" to reduce the purchased electricity from the grid. In the summer case PV power is mostly used to charge the battery and most of the demand is covered from the grid. The battery output is assumed to be controlled at 20 kW for 4 hours. In both cases the battery provides some help but not a significant one.

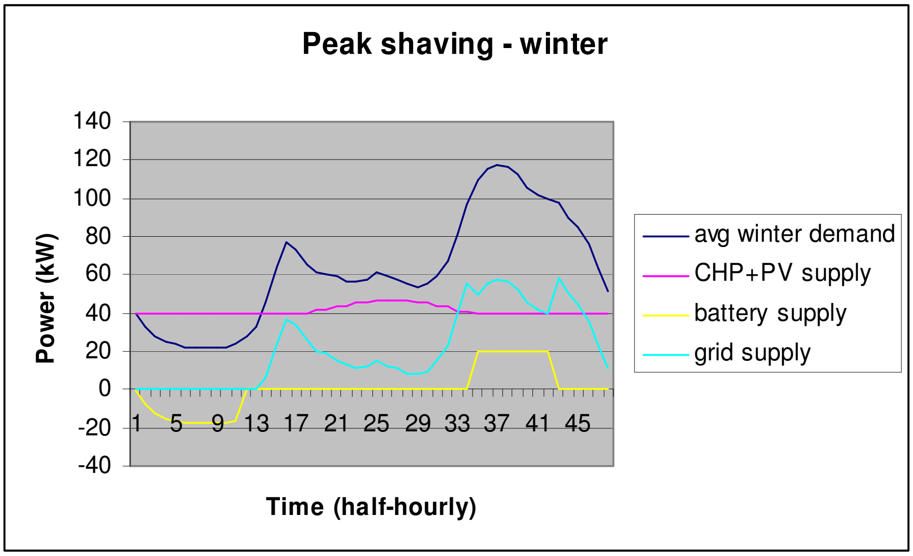


Figure 6-18. Battery peak-shaving for an average winter day

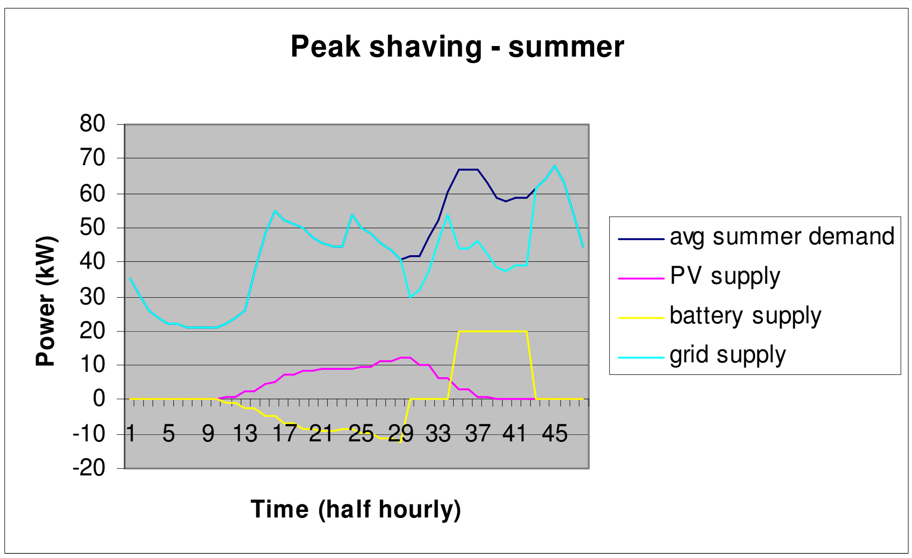


Figure 6-19. Battery peak-shaving for an average summer day

6.3.2. Power Quality

The previous studies showed that DG and especially the battery can have a significant impact in voltage variation situations. Still it cannot be predicted in what state of charge the battery would be in order to respond in voltage regulation problems. The real margins of battery operation would be less than the peak values that were explored in the simulations. That is because batteries are generally controlled for a minimum and maximum state of charge because full or zero charge can damage them and reduce their lifetime. In terms of voltage quality the most flexible operation for the battery would be to remain partly charged so that it can be ready to respond in over and under voltage situations by either operating as load or generation.

7. The Network's Energy Modelling

This chapter is focused on measuring the electrical and thermal performance of the case study network for the demand to be covered. For the energy modelling of the Stutensee LV network the optimisation software HOMER was used in order to measure the electrical-thermal and economical DG performance.

HOMER performs comparative economic analyses on distributed generation power systems. Inputs to HOMER include load data, renewable resource data, system component specifications and costs, and various optimisation parameters (e.g., number of components, percentage of unmet load, etc.). HOMER will perform an hourly simulation of every possible combination of components entered and rank the systems according to user-specified criteria, such as cost of energy (COE), net present cost (NPC) or capital costs. Furthermore, HOMER can perform "sensitivity analyses" in which the values of certain parameters (e.g., fuel cell cost) are varied to determine their impact on the COE.

7.1. Optimisation Inputs

7.1.1. System Description

Figure 7-1 depicts the system with a generator with heat recovery to represent the CHP, PV panels, battery and converter, and grid connection. HOMER also assumes the presence of a boiler whenever a thermal load is considered but this wasn't taken into account in the simulations.

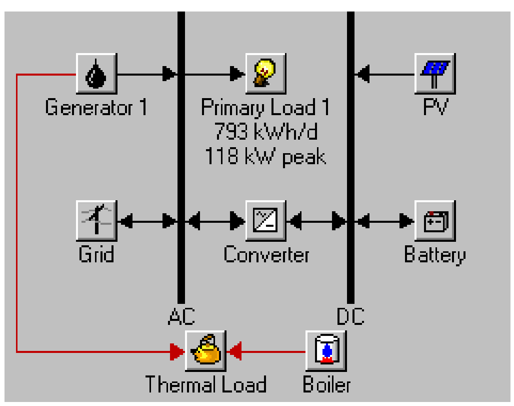


Figure 7-1. System description in HOMER

7.1.2. Electrical Load

The only load data available was a value of 117.77 kW as the maximum load in Stutensee. By using this along with typical residential demand profiles, three hourly profiles were created for winter, spring- autumn, and summer. Homer synthesizes this data and creates and average profile for each month of the year (fig.7-2).

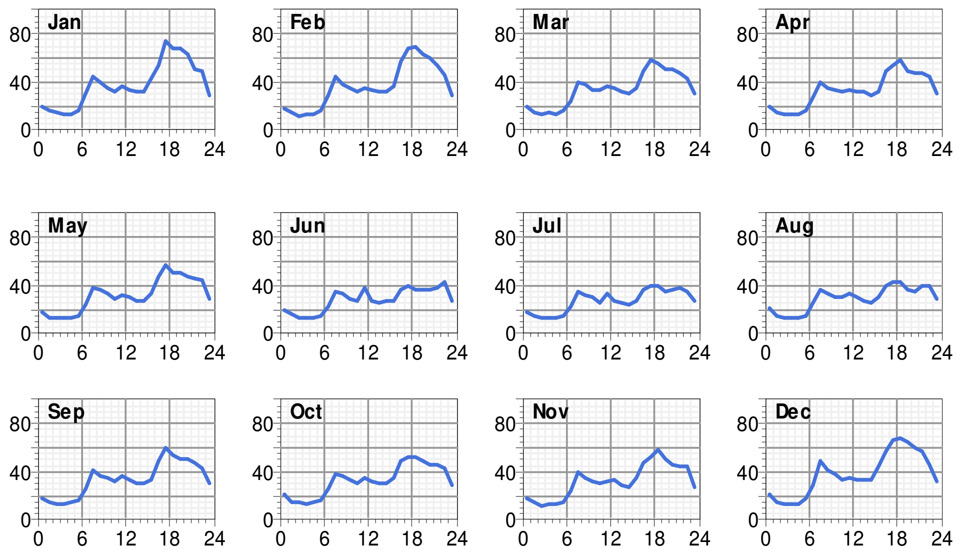


Figure 7-2. Monthly electrical load profiles

7.1.3. Thermal load

No data was available from MVV on thermal demand. The thermal load was created by using typical residential heat profiles and by assuming that it could be covered by the heat output of the CHP. Homer synthesized the data and produced the following monthly heat demands (fig.7-3).

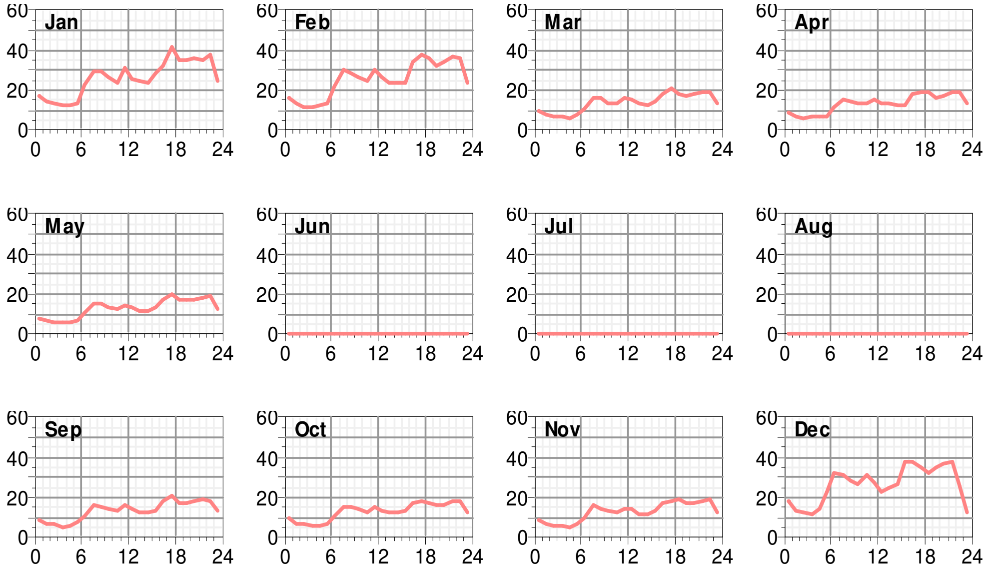


Figure 7-3. Monthly thermal load profiles

7.1.4. Climate Resources

Climate data for the Stuttgart area, where Stutensee is, were available so the solar recourse was easy to be imported. Homer then creates the solar profile of the area (fig.7-4).

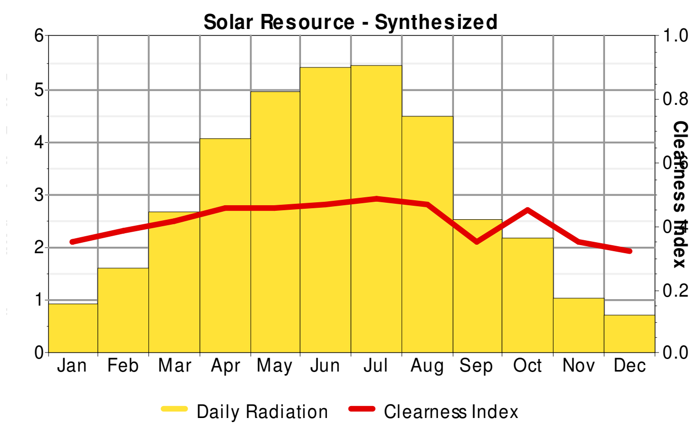


Figure 7-4. Solar resource in the Stutensee area

7.1.5. PV

This scenario was modelled with PV panels fixed at a slope of 48.9°. The installed cost of a 1-kW (peak) PV array ranges between \$6.00/W and \$10.00/W. The baseline capital cost of the PV in this study was \$7000/kW. Lifetimes were assumed to be 20 years. O&M costs for the PV panels were neglected.

7.1.6. CHP

A gas motor with heat recovery was considered in order to model the CHP unit. From the DG technologies cost structure presented earlier in the report the equipment cost is assumed to be 1500$/kW, the replacement cost 1200$/kWh, and the O&M cost 0.018$/kW. Lifetime is assumed 15,000 operating hours.

HOMER can model two dispatch strategies, cycle charging and load following. Which is optimal depends on many factors, including the sizes of the generators and battery bank, the price of fuel, the O&M cost of the generators, the amount of renewable power in the system, and the character of the renewable resources.

The options that HOMER provides for generator control include the dispatch strategy. A dispatch strategy is a set or rules that govern the operation of the generator(s) and the battery bank. HOMER can model two dispatch strategies, cycle charging and load following. Which is optimal depends on many factors, including the sizes of the generators and battery bank, the price of fuel, the O&M cost of the generators, the amount of renewable power in the system, and the character of the renewable resources.

Under the load following strategy, whenever a generator is needed it produces only enough power to meet the demand. Load following tends to be optimal in systems with a lot of renewable power, when the renewable power output sometimes exceeds the load.

Under the cycle charging strategy, whenever a generator has to operate, it operates at full capacity with surplus power going to charge the battery bank. Cycle charging tends to be optimal in systems with little or no renewable power.

In the simulations the generator was set to operate in a cycle charging strategy. As mentioned earlier the proposed scenario is to keep the battery partly charged so that it would be able to respond and improve power quality in possible grid voltage variations. In the simulations the options of 70% as setpoint state of charge will be considered.

7.1.7. Fuel and Electricity Prices

The price of natural gas in Germany is about 0.2$/m^3 [34]. For sensitivity analysis reasons the values of 0.1, 0.15, 0.25 and 0.3$/m^3 will also be considered.

Electricity prices in Germany are relatively high because of substantial private sector involvement. In south-west Germany the cost of electricity is about 0.25$/m^3 [34]. For sensitivity analysis reasons the values of 0.1, 0.15, 0.2 and 0.3$/m^3 will also be considered.

In this study it was assumed a net metering operation of the system. That means that the electricity meter runs backwards when excess electricity is produced. The sell-back price of any excess DG electricity to the grid is considered to be equal to the normal electricity price in all cases.

7.1.8. Battery and Converter

In order to simulate the systems battery a stack of 11 Surrette 4KS25P (1900Ah@4V) was the closest configuration that could be selected. The capital costs for the battery was considered 930$/kWh with minimum lifetime of 4 years. The batteries' efficiency is 93% and the minimum state of charge was assumed at 30%.

A 100kW converter with a cost of 300$/kWh and a 90% efficiency was also considered.

7.1.9. Economics

An annual interest rate of 6% was considered, and the project lifetime was assumed to be 25 years.

7.2. Simulation Results

Table 1 displays the results of the simulation for the system with the existing prices of gas and electricity.

Table 7-1. Simulation results

Natural gas ($/m3)	Power Price ($/kWh)	Total capital	Total NPC	COE ($/kWh)	Renewable fraction	Natural gas (m3)	CHP (hrs)	Batt. Lf. (yr)
0.2	**0.251**	**$ 301,830**	**$ 778,941**	**0.145**	**0.04**	**115,641**	**8,760**	**6.7**

7.2.1. System Performance with the Existing Prices of Fuel and Electricity

The existing system reaches a cost of energy of 0.145$/kWh due to the relatively cheap price of gas. The Net Present Cost (NPC) is $778,941. The numbers can be translated to 8p/kWh and £426,163.

Costs

Table 7-2 shows a more detailed breakdown of the system costs. Each row corresponds to a component of the system, and the final row shows the totals for each column.

Table 7-2. System capital costs

Component	Initial capital ($)	Annualised capital ($/yr)	Annualised replacement ($/yr)	Annual O&M ($/yr)	Annual fuel ($/yr)	Total annualised ($/yr)
PV array	201,600	15,771	1,544	0	0	17,314
Generator	60,000	4,694	28,800	6,307	23,128	62,929
Grid	0	0	0	-24,367	0	-24,367
Battery	10,230	800	1,114	0	0	1,914
Converter	30,000	2,347	797	0	0	3,144
Totals	301,830	23,611	32,255	-18,060	23,128	60,934

The PV installation takes 2/3s of the initial capital investment. The largest part of the replacement and O&M cost is spent on the generator because the optimization results suggest its full time operation with the existing fuel and electricity prices.

Annual electrical energy production

PV array: 43,811 kWh (10%)
CHP: 350,400 kWh (83%)
Grid purchases: 33,114 kWh (7%)

Total: 427,325 kWh

Renewable fraction: 0.043

Annual electric loads served

AC primary loads served: 289,446 kWh
Grid sales: 130,041 kWh

Total load served: 419,487 kWh

Carbon emissions: 35 t/yr

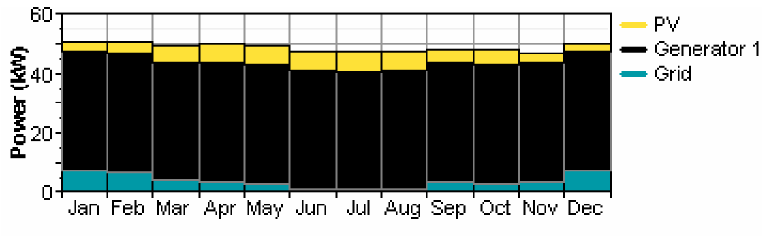


Figure 7-5. Monthly average electricity production

CHP unit

Hours of operation: 8760 hr/yr

Number of starts: 1 starts/yr

Operational life: 1.712 yr

Annual fuel consumption: 115,641 m^3/yr

Battery

Battery throughput: 17,993 kWh

Battery life: 6,66 years

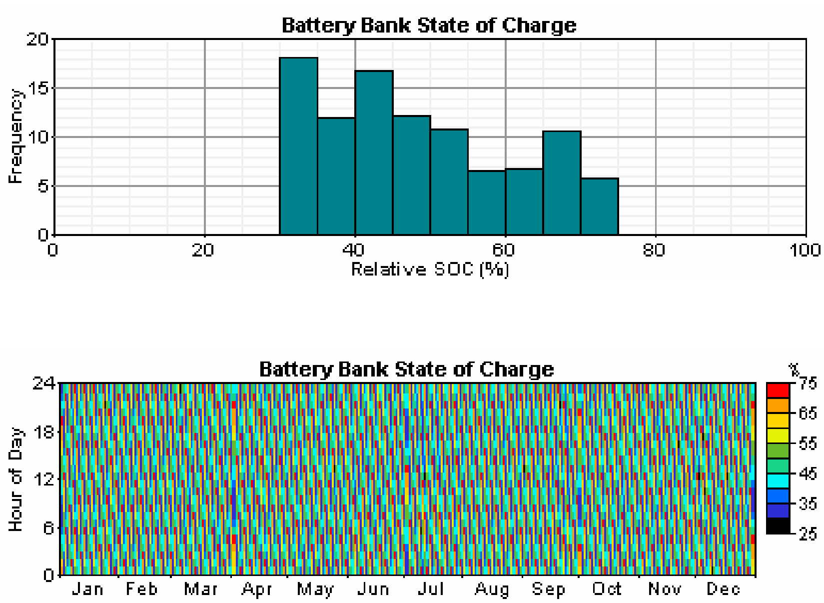


Figure 7-6, Figure 7-7. Battery bank state of charge

Grid

kWh $

Total grid purchases: 30,140 7,577

Total grid sales: 128,794 32,379

Net grid purchases: -98,654 -24,802

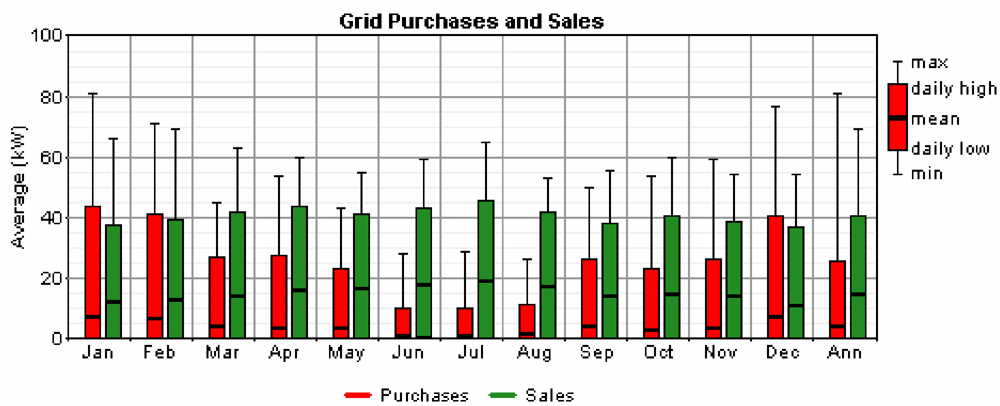


Figure 7-8. Grid purchases and sales

<u>Supply and Demand</u>

The following figures 43-45 show examples of the systems supply and demand operation in different seasons (summer and winter).

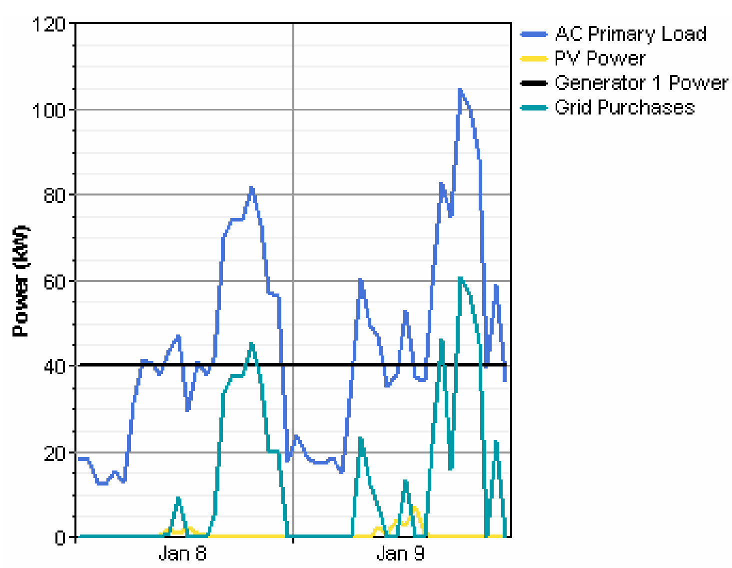


Figure 7-9. Electrical performance for a pair of winter days

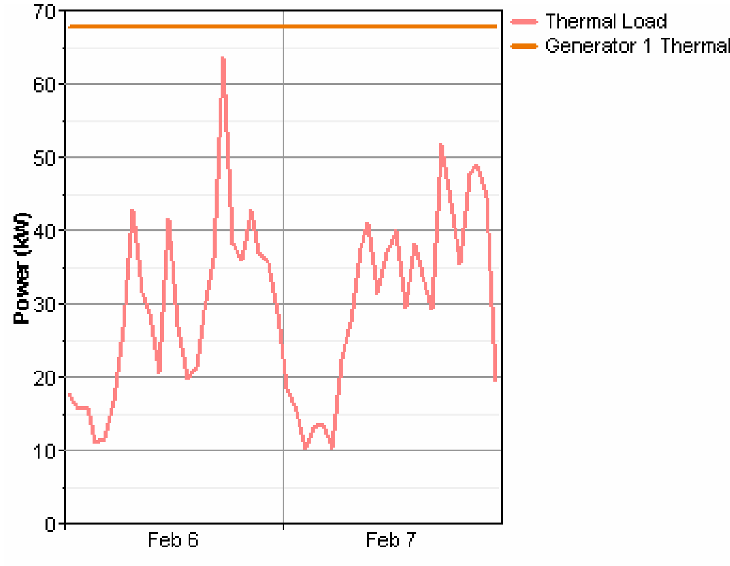


Figure 7-10. Thermal performance for a pair of winter days

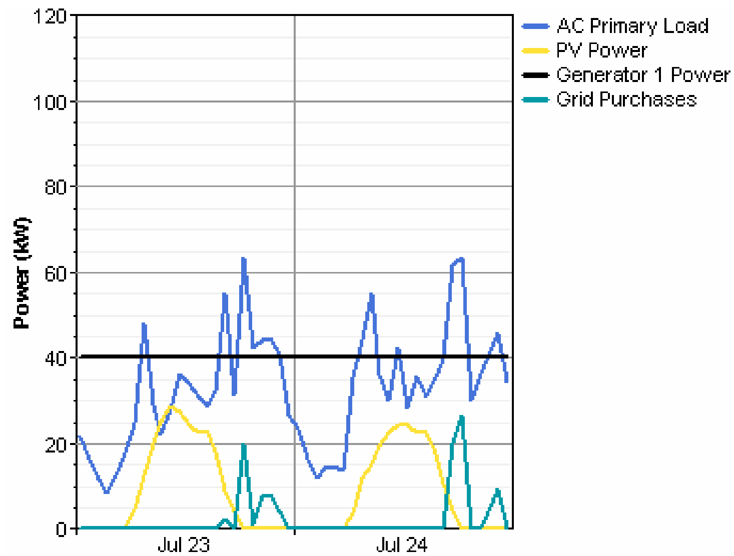


Figure 7-11. Electrical performance for a pair of summer days

The results show that with the existing prices of fuel and power the most economic operation of the system is to run the CHP full time for the whole year, even when the thermal load is minimized in the summer period. In this case the CHP unit provides 83% of the whole energy production. The PV panels produce an important and renewable 10%.The battery state of charge varies from 30 to 70% as adjusted.

The thermal load as assumed can always be covered from the CHP output (fig.7-10). Any excess electricity in low demand hour can be sold back to the grid on the same relatively high power price.

In the summer with the increased performance of the PV panels the purchases from the grid are very low.

7.2.2. Sensitivity Analysis

A graphic representation of the sensitivity analysis can be seen in the following graph. The graph shows how the cost of energy varies in correlation with the prices of fuel and electricity. The first row which is in bold represents the existing prices of gas and electricity.

Table 7-3. Sensitivity analysis

Natural gas ($/m3)	Power Price ($/kWh)	Total capital	Total NPC	COE ($/kWh)	Renewable fraction	Natural gas (m3)	CHP (hrs)	Batt. Lf. (yr)
0.2	**0.251**	**$ 301,830**	**$ 778,941**	**0.145**	**0.04**	**115,641**	**8,760**	**6.7**
0.2	0.1	$ 301,830	$ 679,116	0.183	0.11	12,937	0	12
0.2	0.15	$ 301,830	$ 826,977	0.218	0.1	22,744	1,009	12
0.2	0.2	$ 301,830	$ 842,705	0.157	0.04	115,641	8,760	6.7
0.2	0.3	$ 301,830	$ 718,745	0.134	0.04	115,641	8,760	6.7
0.2	0.35	$ 301,830	$ 656,740	0.122	0.04	115,641	8,760	6.7
0.15	0.251	$ 301,830	$ 705,027	0.131	0.04	115,641	8,760	6.7
0.15	0.1	$ 301,830	$ 670,847	0.181	0.11	12,937	0	12
0.15	0.15	$ 301,830	$ 814,947	0.179	0.06	76,311	5,725	9
0.15	0.2	$ 301,830	$ 768,777	0.143	0.04	115,641	8,760	6.7
0.15	0.3	$ 301,830	$ 644,818	0.12	0.04	115,641	8,760	6.7
0.15	0.35	$ 301,830	$ 582,827	0.109	0.04	115,641	8,760	6.7
0.25	0.251	$ 301,830	$ 852,867	0.159	0.04	115,641	8,760	6.7
0.25	0.1	$ 301,830	$ 686,867	0.185	0.11	12,993	5	12
0.25	0.1	$ 301,830	$ 687,385	0.185	0.11	12,937	0	12
0.25	0.15	$ 301,830	$ 845,624	0.227	0.11	14,084	118	12
0.25	0.2	$ 301,830	$ 917,047	0.172	0.04	114,429	8,668	6.7
0.25	0.3	$ 301,830	$ 792,658	0.148	0.04	115,641	8,760	6.7
0.25	0.35	$ 301,830	$ 730,653	0.136	0.04	115,641	8,760	6.7
0.3	0.251	$ 301,830	$ 926,859	0.173	0.04	115,641	8,760	6.7
0.3	0.1	$ 301,830	$ 695,655	0.188	0.11	12,937	0	12
0.3	0.15	$ 301,830	$ 855,515	0.231	0.11	13,061	14	12
0.3	0.2	$ 301,830	$ 977,512	0.206	0.05	83,697	6,324	8.6
0.3	0.3	$ 301,830	$ 866,575	0.162	0.04	115,641	8,760	6.7
0.3	0.35	$ 301,830	$ 804,567	0.15	0.04	115,641	8,760	6.7
0.1	0.251	$ 301,830	$ 631,122	0.118	0.04	115,641	8,760	6.7
0.1	0.1	$ 301,830	$ 662,580	0.179	0.11	12,937	0	12
0.1	0.15	$ 301,830	$ 756,831	0.141	0.04	115,628	8,759	6.7
0.1	0.2	$ 301,830	$ 694,840	0.13	0.04	115,641	8,760	6.7
0.1	0.3	$ 301,830	$ 570,908	0.107	0.04	115,641	8,760	6.7
0.1	0.35	$ 301,830	$ 508,904	0.095	0.04	115,641	8,760	6.7

The lowest Costs of Energy are achieved in the cases were the fuel is very cheap and electricity very expensive. On the other hand cheap electricity along with expensive fuel does not result to such low Costs of Energy, reasonably because fuel has to be used anyway to cover the thermal load.

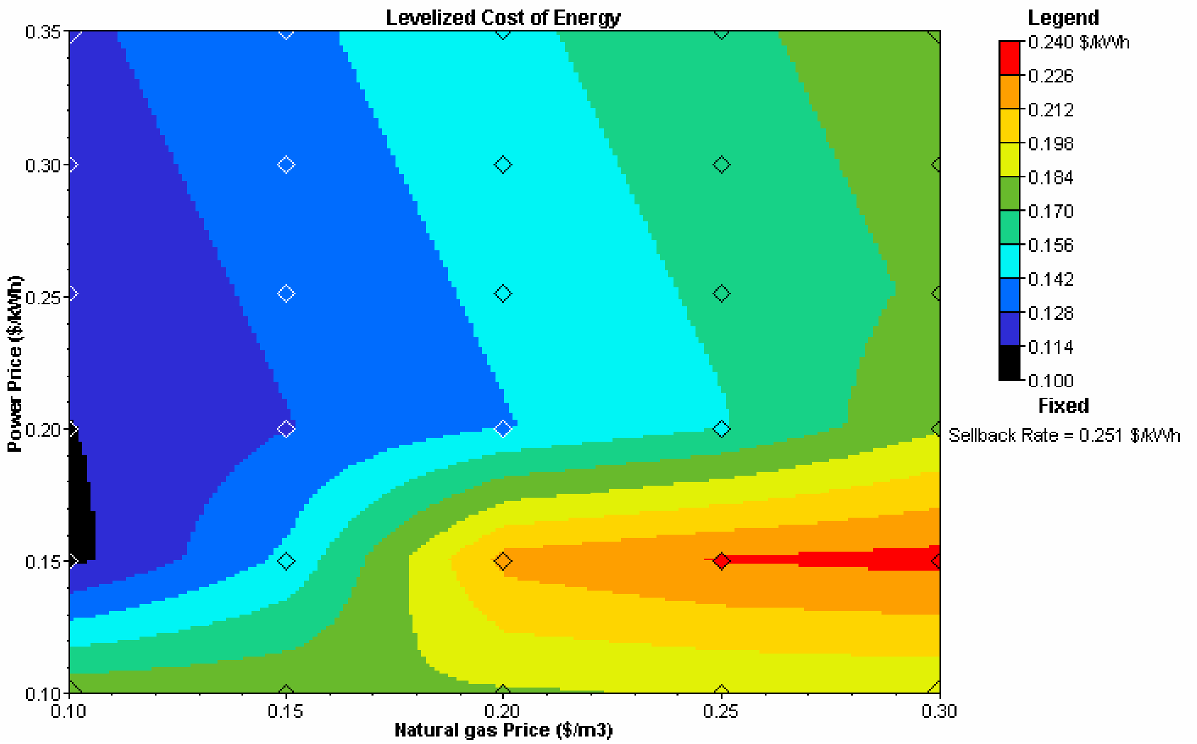


Figure 7-12. Cost of Energy sensitivity analysis

In the cases when the optimized operation of the system requires the CHP to run for 8760 hr/ yr, the system performance is similar with that of the "real case" for which the results were already presented.

Next some of the results in the case of a bit lower prices of gas and electricity (0.15\$/m^3 and 0.15\$/kWh) are presented. These prices are close to the British standards and show how the system would pretty much perform in Britain.

The NPC in that case is \$814,947 and the COE is 0.179\$/kWh. The prices can be translated to £449,254 and 10p/kWh.

The following figures 7-13,14,15 show the system performance throughout the year with these electricity prices.

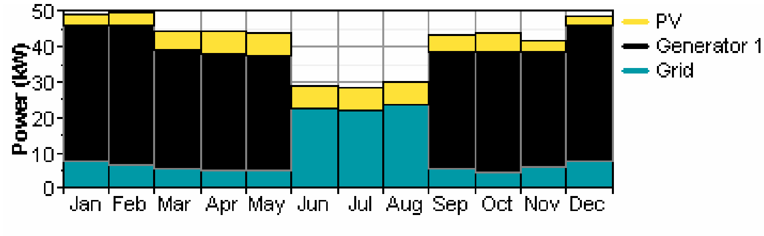


Figure 7-13. Monthly average electrical production

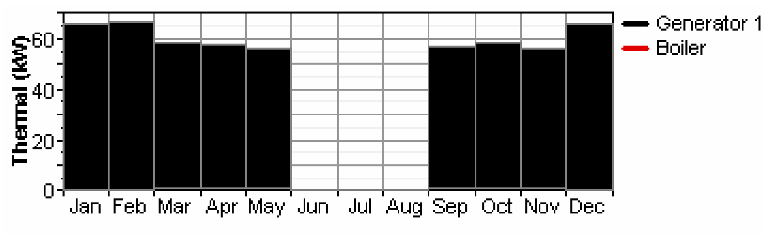


Figure 7-14. Monthly average thermal production

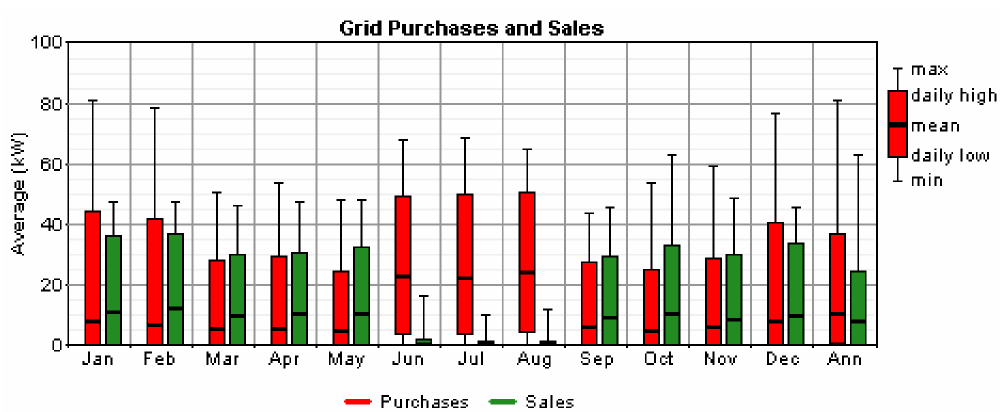


Figure 7-15. Grid sales and purchases

In this case the CHP makes 150 starts/yr. As it can be seen in this case the heat demand dictates the CHP operation so in the summer period the CHP is off. It is more economical to get the power from the grid at that season instead of continuously running the CHP.

An example of the electrical output of two winter and summer days in this case can be seen in the following figures:

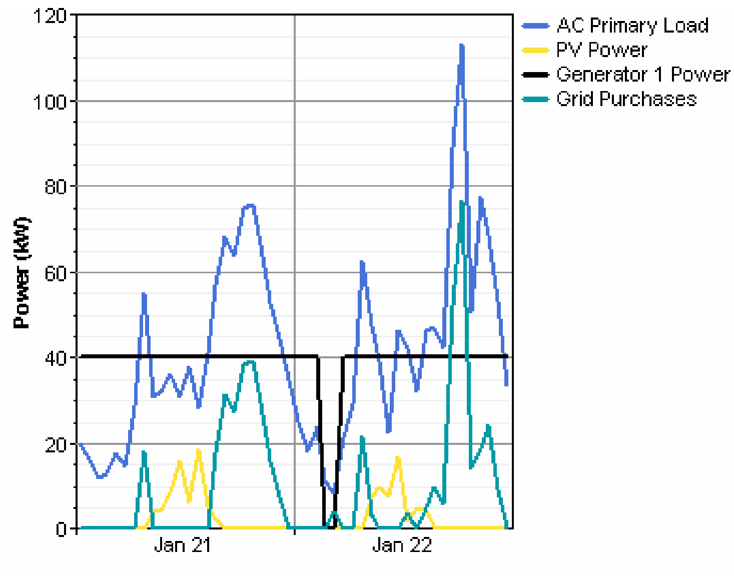


Figure 7-16. Electrical performance for a pair of winter days

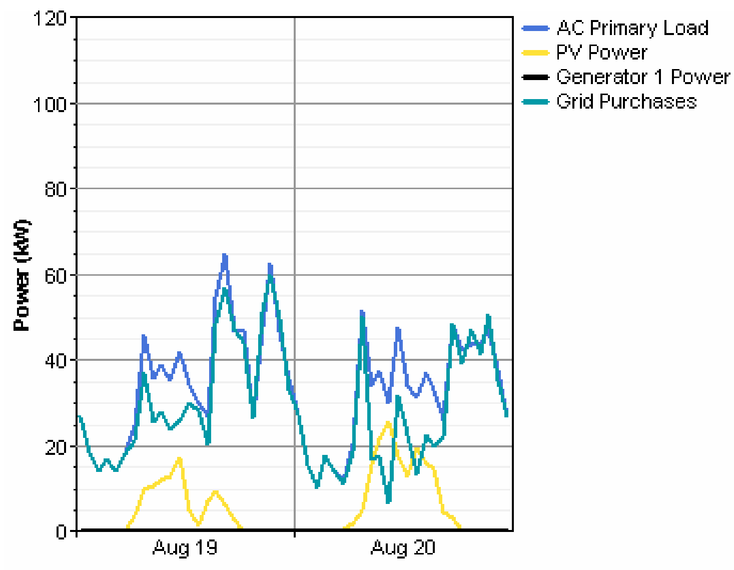


Figure 7-17. Electrical performance for a pair of summer days.

7.3. Conclusions

The studies show that DG can have a significant impact in a typical low voltage network. In the Stutensee installation DG can produce a large portion of the site's energy needs with lower generation costs. It also provides a flexible tool for compensating voltage fluctuations of a certain size from the central grid, contributing to improved reliability and power quality.

CHP

A CHP unit that matches the thermal load is an effective investment for LV networks. It reaches high efficiency numbers, and provides excellent fuel economy.

Cogeneration applications vary in their operation, sizes and expandability. CHP is economically attractive for DG because of its higher fuel efficiency and low incremental capital costs for heat-recovery equipment. The size of the CHP system matters: the most economical are those that match the thermal load. Economies of scale also matter. More than 80% of CHP capacity is in large industrial applications, mostly in four industries: paper, chemicals, petroleum refining and food processing. Even so, much of the CHP capacity in Europe has been developed as a consequence of supportive government policies. Such policies have also encouraged systems to produce power for export to the grid [14] [35]. Selling power to the grid was also a key issue for the Stutensee DG installation to appear economically attractive.

The relative prices of retail electricity and fuel costs are critical to the competitiveness of any DG option. This ratio varies greatly from country to country. In Japan, for example, where electricity and natural gas prices are high, DG is attractive only for oil-fired generation. In other countries, where gas is inexpensive compared to electricity, like the Stutensee case study DG can become economically attractive – see figure 7-18.

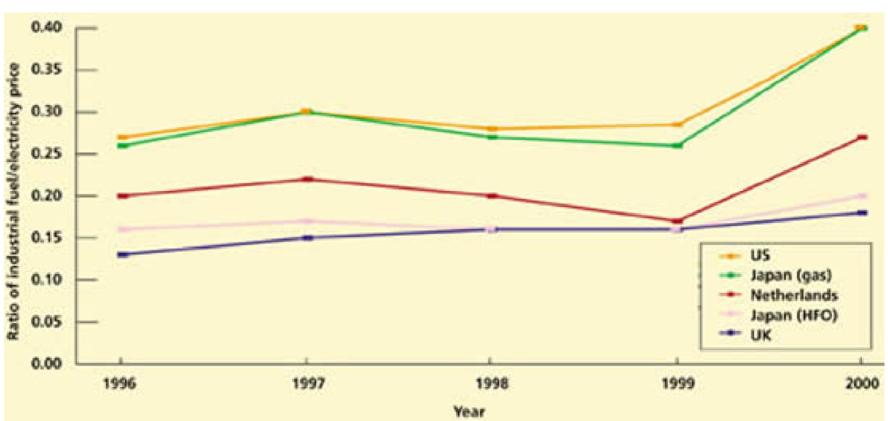


Figure 7-18. Fuel/Electricity prices ratio around the world [20]

PV

The PVs effectiveness and contribution to the system is harder to measure. By considering the same system without the PV panels we get a result for a COE of 0.141$/kWh which is a bit less than the 0.145$/kWh with their presence and the total capital cost falls for about $100,000.

If we consider that the installation cost for the PVs is half of the existing ($3500 instead of $7000) then the system reaches a COE of 0.124$/kWh, and the total capital is again about $100,000 less.

As the prices tend to fall investments like these will get to be more economically competitive. Introductions of green – tariff pricing can also be an important incentive for photovoltaic installations. [35]

In the Stutensee case they provide a very respectable 10% of the total annual consumption. The increase of performance the summer period contributes in minimizing grid purchases (see figure 7-19)

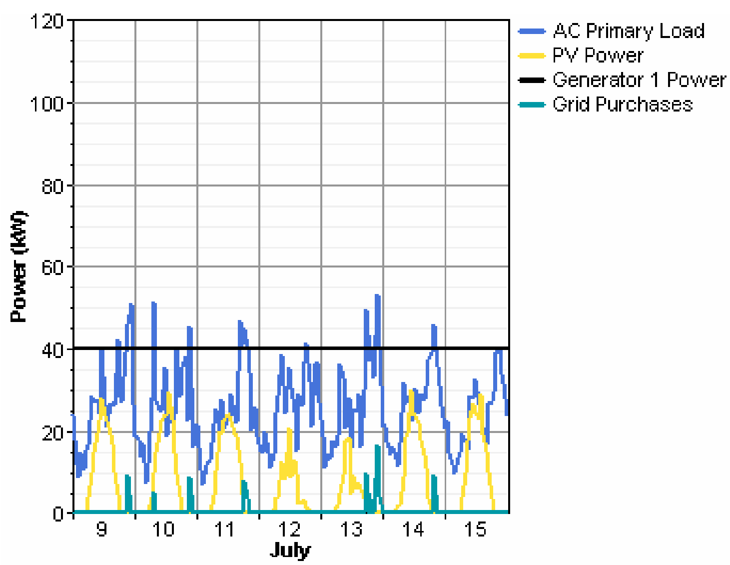


Figure 7-19, Electrical performance for a summer week

Battery

The battery is the most controllable of the DG elements of the Stutensee installation. Its contribution in normal operating conditions is not big with a throughput of 17,993kWh annually.

On the other hand, the presence of energy storage devices with the flexibility of operating either as generation or loads result in improved voltage control and power quality.

8. Conclusions

Distributed generation is expected to play a greater role in power generation over the coming decades, especially close to the end-use low voltage consumer side. There is a growing interest on the part of power consumers for installing their own generating capacity in order to take advantage of flexible DG technologies to produce power during favourable times, enhance power reliability and quality, or supply heating/cooling needs. The range of DG technologies and the variability in their size, performance, and suitable applications suggest that DG could provide power supply solutions in many different industrial, commercial, and residential settings. In this way, DG is contributing to improving the security of electricity supply.

A main component in a DG installation unit can always be a cogeneration unit. CHP can convert over 80% of the fuel into usable energy. Depending on the ratio between fuel and electricity prices a cogeneration unit can always be operated in a flexible way in order to reduce the overall energy cost. In the case study the cogeneration unit has the ability to provide about 80% of the annual electrical demand and also satisfy the heat load of the installation.

The low emissions of cogeneration to the environment establish it as the most favorable technology in order to meet the Kyoto Protocol targets. More than 20% of the whole energy production is to come by cogeneration (figure 8-1)

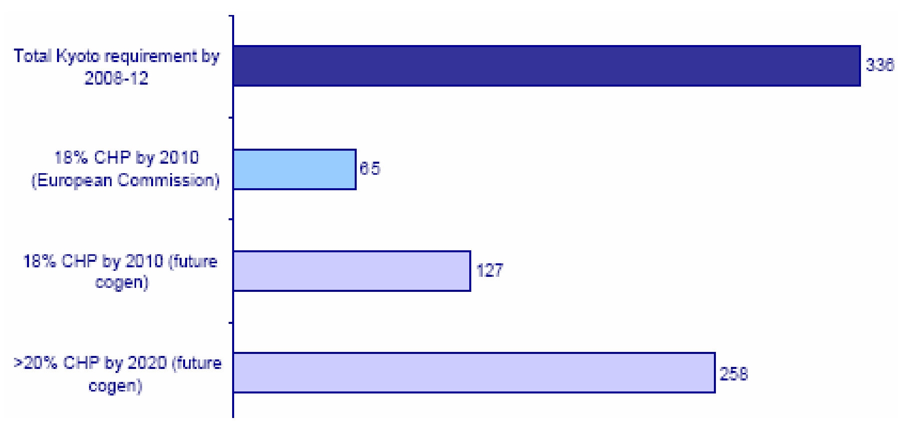


Figure 8-1. Reductions of Greenhouse Gas Emissions required under the Kyoto Protocol and the potential contribution of Cogeneration to this target (Million tonnes of CO2 equivalent) [35]

Renewable technologies like photovoltaics still appear to be an expensive investment. On the other hand, the continuous reduction in their price combined with their low operation and maintenance costs will provide an environmentally friendly means of producing electricity. An important aspect of their operation is also that they produce electricity in hours of the day that most of it can be directly used avoiding storage losses.

Energy storage devices such as batteries and fuel cells are controllable components, with flexibility of operation and they can contribute in increased reliability and power quality.

The expansion of customers' potential investments in distributed generation in low voltage networks could be assisted in two general ways. One would be to standardize and clarify the rules and procedures governing the installation and operation of distributed generators and their interconnection with the grid. That approach could assist the approval process and help to reduce uncertainty about the requirements and costs of compliance. The second would be to set the prices that operators of distributed generators pay and receive for electric power, connection to the grid, and transmission and distribution services at levels consistent with the actual costs borne by utilities to provide those services. That change could give operators incentives to install and operate distributed generators at a level that would help to ensure the lowest cost of electricity for all customers.

The most important initiatives that would allow an economic and wider use of distributed generation include the following:

- Ensure access to the grid for distributed generators under uniform technical and contractual terms and charges for interconnection that are based on economic costs, so that owners know in advance the requirements for parallel interconnection and manufacturers can design standard packages to meet technical requirements;

- Establish prices that owners of distributed generators both pay and receive for electricity at levels consistent with utilities' wholesale hourly costs to deliver power to different locations, and set uniform, explicit rates for standby electricity service based on costs – so that owners can decide between purchasing or generating power on the basis of prices that reflect utilities' incremental costs of serving them; and

- Set uniform requirements for emissions, land use, and building codes that are based on the technology of electricity generation – so that manufacturers can design suitable units and owners of distributed generators are not restricted in their siting and operating decisions relative to other new sources of generation.

If DG does take a large share of the generation market, the role of distribution utilities will become vastly more important than currently. There will be a need to reform distribution system design requirements to accommodate DG. Undertaking further studies to identify the technical capabilities, the operating strategies, and the skill requirements of distribution network operators would help prepare electricity markets for a more decentralized electricity system.

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Appendix

Levelized Cost of Energy

Type: Output Variable
Units: $/kWh
Symbol: *COE*

The levelized cost of energy is the average cost of producing electricity. HOMER calculates the COE using the following formula:

$$COE = \frac{C_{ann,tot}}{E_{prim} + E_{def} + E_{grid,sales}}$$

where:

$C_{ann,tot}$ = total annualized cost of the system [$/yr]
E_{prim} = primary load served [kWh/yr]
E_{def} = deferrable load served [kWh/yr]
$E_{grid,sales}$ = total grid sales [kWh/yr]

Total Net Present Cost

Type: Output Variable
Units: $
Symbol: C_{NPC}

The total net present cost is HOMER's main economic output. All systems are ranked according to net present cost, and all other economic outputs are calculated for the purpose of finding the net present cost. The net present cost is calculated according to the following equation:

$$C_{NPC} = \frac{C_{ann,tot}}{\mathrm{CRF}\left(i, R_{proj}\right)}$$

Where:

$C_{ann,tot}$ = total annualized cost [$/yr]
CRF() = capital recovery factor
i = interest rate [%]
R_{proj} = project lifetime [yr]

O&M (Operation and Maintenance) Cost

The O&M cost of a component is the annual cost of operating and maintaining that component.

Replacement Cost

The replacement cost is the cost of replacing a component at the end of its lifetime. This may be different from the initial capital cost for several reasons:

- Not all of the component may require replacement at the end of its life. For example, the wind turbine nacelle may need replacement but the tower may not.
- The initial capital cost may be reduced or eliminated by a donor organization, but the replacement cost may not.
- You may want to account for the fixed costs (e.g. travel cost) of a visit to the site. At initial construction, these costs are shared by all components, but at replacement time they may not.
- You may want to account for a reduction over time in the purchase cost of a particular technology.

Important: the replacement cost is not meant to account for **inflation**. All costs in HOMER are *real costs*, defined in terms of constant dollars. For more information, please see interest rate.

The replacement cost is used to calculate the annualized replacement cost.

Dispatch Strategy

A *dispatch strategy* is a set of rules used to control the operation of the generator(s) and the battery bank whenever there is insufficient renewable energy to supply the load.

Absolute State of Charge

The absolute state of charge is the total amount of energy currently contained in the battery bank, measured in kWh. When the batteries are fully charged, the absolute state of charge is equal to the maximum capacity of the battery bank.

State of charge is often abbreviated as SOC.

Relative State of Charge

The relative state of charge is the ratio of the current absolute state of charge to the maximum capacity of the battery bank. When the batteries are fully charged, the relative state of charge is 100%. Wherever HOMER reports the amount of energy stored in the battery bank, it reports the relative state of charge.

State of charge is often abbreviated as SOC.

Battery Minimum State Of Charge

Type: Input Variable
Units: %
Symbol: q_{min}

The relative state of charge below which the battery bank is never drawn - specified as a percentage of the total capacity. Most rechargeable batteries are not meant to be fully discharged. In fact, fully discharging some batteries can permanently damage them. The minimum state of charge is typically set to 30-50% in order to avoid damaging the battery bank by excessive discharge.

Interest Rate

Type: Input Variable
Units: %
Symbol: i

The interest rate that one enters for HOMER's input is the annual real interest rate (also called the *real interest rate* or just *interest rate*). It is the discount rate used to convert between one-time costs and annualized costs. It is found in the Economic Inputs window. The annual real interest rate is related to the nominal interest rate by the equation given below.

$$i = \frac{i' - f}{1 + f}$$

where:

i = real interest rate
i' = nominal interest rate (the rate at which you could get a loan)
f = annual inflation rate

For example, if the nominal interest rate is 8% and the inflation rate is 3.5%, the annual real interest rate is 4.35%.

By defining the interest rate in this way, **inflation** is factored out of the economic analysis. All costs therefore become *real costs*, meaning that they are in defined in terms of constant dollars. The assumption is that the rate of inflation is the same for all costs.

Project Lifetime

The number of years over which the net present cost of the project should be calculated.

Initial Capital Cost

The initial capital cost of a component is the total installed cost of that component at the beginning of the project.

Annualized Capital Cost

HOMER annualizes the initial capital of each component over the project lifetime to calculate its annualized capital cost. The Costs page of the Simulation Results window displays the annualized capital cost of each system component along with the total annualized capital cost.

HOMER calculates the annualized capital cost of each component using the following equation:

$$C_{acap} = C_{cap} \cdot \mathbf{CRF}(i, R_{proj})$$

where:

C_{cap} = initial capital cost of the component
CRF() = capital recovery factor
i = interest rate
R_{proj} = project lifetime

Note: HOMER calculates the other annualized capital cost in a different way.

Annualized Replacement Cost

The annualized replacement cost of a system component is the annualized value of all the replacement costs occurring throughout the lifetime of the project, **minus** the salvage value at the end of the project lifetime.

Note: The annualized replacement cost can be negative because it includes the annualized salvage value.

HOMER uses the following equation to calculate each component's annualized capital cost:

$$C_{arep} = C_{rep} \cdot \left[f_{rep} \cdot \mathrm{SFF}(i, R_{comp}) - (R_{rem}/R_{comp}) \cdot \mathrm{SFF}(i, R_{proj}) \right]$$

f_{rep}, a factor arising because the component lifetime can be different from the project lifetime, is given by:

$$f_{rep} = \begin{cases} \mathrm{CRF}(i, R_{proj}) / \mathrm{CRF}(i, R_{rep}) & , R_{rep} > 0 \\ 0 & , R_{rep} = 0 \end{cases}$$

R_{rep}, the replacement cost duration, is given by:

$$R_{rep} = R_{comp} \cdot \mathrm{INT}\left(\frac{R_{proj}}{R_{comp}} \right)$$

and R_{rem}, the remaining life of the component at the end of the project lifetime, is given by:

$$R_{rem} = R_{comp} - \left(R_{proj} - R_{rep} \right)$$

other definitions:

C_{rep}	= replacement cost of the component.
SFF()	= sinking fund factor
i	= interest rate
R_{comp}	= lifetime of the component
R_{proj}	= project lifetime

HOMER assumes linear depreciation of components, so that the salvage value of the component at the end of the project lifetime is proportional to its remaining life. The salvage value S is assumed to obey the following relation:

The annualized capital cost of each system component is displayed on the Costs page of the Simulation Results window.

O&M (Operation and Maintenance) Cost

The O&M cost of a component is the annual cost of operating and maintaining that component. HOMER displays the O&M cost of each component in the Costs page of the Simulation Results window.

Note: The grid O&M cost is the annual cost of buying electricity from the grid.

Annualized Cost

The annualized cost of a component is equal to its annual operating cost plus its capital and replacement costs annualized over the project lifetime. The annualized cost of each component is equal to the sum of its:

- annualized capital cost
- annualized replacement cost
- annual O&M cost
- annual fuel cost (if applicable)

The annualized cost is useful for comparing the costs of different components because it measures their relative contribution to the total net present cost. It allows for a fair cost comparison between components with low capital and high operating costs (such as diesel generators) and those with high capital and low operating costs (such as PV arrays or wind turbines).

The annualized cost of each system component is displayed on the Costs page of the Simulation Results window, along with the total annualized cost.