TAMPERE UNIVERSITY OF TECHNOLOGY

ATTE LÖF

TESTING OF LOW VOLTAGE NETWORK AUTOMATION

Master of Science Thesis

Examiner: Professor Sami Repo
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ABSTRACT

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The role of the low voltage network in the distribution network is becoming more important. Customer's demand for better power quality and distribution reliability is increasing in the future. In addition, distributed generation is expected to increase, which will have effect on the low voltage network operation. Remotely readable smart meters have been installed to most of the customers in Finland and those meters enable more effective monitoring and control of the low voltage network. In addition, smart measurement devices developed for the secondary distribution substation can also be utilized to improve the low voltage network management. Information from smart meters and distribution substation can be utilized in power quality management, fault management, network planning and operation of the low voltage network.

The aim of this thesis was to study how measurements from smart meters and distribution substation could be utilized in the low voltage network monitoring and management. Simple three-phase low voltage network was modelled in this thesis and it consists of one low voltage feeder and seven customers. Real-time digital simulator was used in the simulations of this thesis. Current and voltage signals from the real-time digital simulator were amplified to real current and voltage levels that were measured by real smart meters and RTU at distribution substation. Measured information was send to database, and from the database to the control system. Changes and alarms in the low voltage network were monitored almost in real-time with the control system.

Main studies of this thesis were low voltage network monitoring, load congestion management and fault management. Monitoring of the low voltage network was tested by creating different kinds of situations to low voltage network and by observing how well the control system can detect these changes. The load congestion management was tested with state estimation algorithm that was installed to the PC at secondary substation. The state estimation algorithm was used for current, voltage and power flow estimations in the network. Fault management was tested with fault location algorithm that was also installed to the PC. It was used for detecting the faulted area of the network. In addition, isolation of customer in dangerous situation, such as broken neutral conductor, was also tested.

Results of this thesis show that measurement information from smart meters and RTU will significantly improve the monitoring and management of the low voltage network. These features provide accurate and almost real-time information of the low voltage network, which can be used to increase the automation level in the low voltage network. Unwanted loading situations could be avoided with real-time information, which will increase the lifetime of the low voltage network and increase the utilization rate of network. Quickly located faults will decrease the interruption costs and quick isolations of customers in dangerous situations will improve the safety of the network.

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Pienjänniteverkon rooli jakeluverkossa on tulevaisuudessa kasvamassa. Yksittäisen asiakkaan odotukset sähkön laadusta ja toimitusvarmuudesta kasvavat ja keskeytyksistä aiheutuvat kustannukset tulevat nousemaan. Lisäksi hajautetun tuotannon odotetaan kasvavan pienjänniteverkossa, joka tulee vaikuttamaan jakeluverkon toimintaan huomattavasti. Etäluettavia mittareita on asennettu suurimmalle osalle Suomessa ja niiden käyttäminen mahdollistaa pienjänniteverkon tehokkaamman käytön ja valvonnan. Lisäksi jakelumuuntajille kehitettyjen älykkäiden mittauslaitteiden avulla pystytään parantamaan pienjänniteverkon käyttöä ja valvontaa. Jakelumuuntamolta ja etäluettavilta mittareilta saatavia tietoja pystytään hyödyntämään mm. sähkön laadun valvonnassa, vikojen hallinnassa, sähköverkon suunnittelussa ja käyttötoiminnassa.

Tämän työn tavoitteena on tutkia jakelumuuntajalla ja etäluettavilla mittareilla suoritettavien mittausten hyödyntämistä pienjänniteverkon valvonnassa ja hallinnassa. Diplomityössä mallinnettiin yksinkertainen kolmivaiheinen pienjänniteverkko, joka koostuu yhdestä jakelumuuntajan lähdöstä ja seitsemästä asiakkaasta. Sähköverkkoa simuloitiin RTDS-reaaliaikasimulaattorilla, josta muuntajan ja asiakkaiden virtojen ja jännitteiden signaalit siirrettiin vahvistimien avulla todellisille mittalaitteille. Mittalaitteiden mittaamat tiedot siirrettiin tiedonsiirtoverkon avulla tietokantaan, josta ne luettiin valvontaohjelmaan. Pienjänniteverkossa tapahtuvia muutoksia ja hälytyksiä pystyttiin seuraamaan lähes reaaliajassa valvontaohjelman avulla.

Tässä työssä tutkittavat asiat painottuivat pienjänniteverkon valvontaan sekä kuormituksen muutosten seurantaan ja vikojen hallintaan. Pienjänniteverkon valvontaa tarkasteltiin luomalla erilaisia tilanteita sähköverkkoon ja seuraamalla kuinka tarkkaan valvontaohjelma pystyy näitä muutoksia havaitsemaan. Kuormituksen muutosten seurantaa tarkasteltiin jakelumuuntajalla olevalle tietokoneelle asennetulla tilaestimointialgoritmilla, jonka avulla sähköverkon tehovirtauksia ja asiakkaiden virtoja ja jännitteitä pystyttiin estimoimaan. Vikojen hallintaa tarkasteltiin myös jakelumuuntajan tietokoneelle asennetulla vika-algoritmilla, jota käytettiin vikapaikkojen paikantamiseen. Lisäksi vian hallinnassa kokeiltiin vaarallisten vikojen, kuten nollavian, poistamista pienjänniteverkosta.

Tämän työn tutkimustuloksien perusteella voidaan todeta, että mittalaitteilta saatavien tietojen avulla pienjänniteverkon valvontaa ja käytön hallintaa pystytään huomattavasti parantamaan. Mittalaitteiden avulla pienjänniteverkon tilasta saadaan lähes reaaliaikaista tietoa, jonka avulla pienjänniteverkon automaatioastetta voidaan kasvattaa. Kuormitustilanteen kasvaminen pienjänniteverkossa voidaan havaita nopeasti ja siihen pystytään reagoimaan nopeammin. Täten voidaan estää verkon liiallinen kuormittuminen ja samalla pidentää verkon käyttöikää sekä parantaa sen käyttöastetta. Vikojen nopea paikantaminen vähentää keskeytyksistä aiheutuvia kustannuksia ja vaarallisten vikojen nopea poistaminen parantaa turvallisuutta sähköverkossa.

PREFACE

This Master of Science thesis was done in Tampere University of Technology in the Department of Electrical Energy Engineering and it is a part of INTEGRIS project (The research leading to these results has received funding from the European Union European Atomic Energy Community Seventh Framework Programme under grant agreement n° 247938.). The supervisor of this thesis has been Professor Sami Repo and I would like to thank him for good advice and help during the writing process. I also would like to thank my co-workers for pleasant working environment and for the many advices that you have given to me during the time I have been working at the department.

I would like to thank my mother for financial and emotional support during my studies and my brother for good advice for the thesis and for being my brother. I also want to thank my father, who passed away too early, for raising me to a decent young man together with my mother.

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Tampere 21.01.2013

Atte Löf

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LIST OF ABBREVIATIONS AND NOTATION

AMI	Advanced Metering Infrastructure
AMR	Automatic Meter Reading
DLMS	Device Language Message Specification
DMS	Distribution Management System
GPRS	General Packet Radio Service
GPS	Global Positioning System
HV	High Voltage
ICT	Information and Communication Technology
LV	Low Voltage
MV	Medium Voltage
NTP	Network Time Protocol
RTDS	Real-Time Digital Simulator
RTU	Remote Terminal Unit
SCADA	Supervisory Control And Data Acquisition
SMS	Short Message Service

1 INTRODUCTION

Today’s electric power supply is based on centralized power supply. Electrical energy is produced in large power plants and transferred to the customers through the main grid and distribution network. Electric power is usually fed only one direction from primary substation to consumption points. The existing distribution network would be more efficient if energy production would be installed near the consumption points. Therefore, the number of distributed energy resources, such as energy storages and controllable loads, is expected to increase in the future LV (Low Voltage) network. Installing distributed energy resources to the LV network is going to change power flows in the distribution system. Power no longer flows in one direction only and the distribution network is going to be more complex. That is why it calls for improved monitoring and adjustability.

Demands for better power quality, distribution reliability and the evolution of the electric generation are the factors for progressing distribution network automation. Interruption cost in electricity supply is increasing and the electricity distribution companies want to reduce it and offer better quality electricity. Changing the distribution network automation to a more intelligent system is challenging, particularly in the LV network where the automation level has so far been very low. These changes will be inevitable, if distributed generation and distributed energy resources increase in the future LV network, as predicted. That is why the role of the LV network in the electric power supply has become more important and more intelligent solutions are required.

Today the real-time information about the distribution network state is mainly gathered from the primary substations (HV/MV) and the MV (Medium Voltage) network. Continuous monitoring at the LV network level is very rare and the amount of gathered information has been low enough to manage with present ICT (Information and Communication Technology) systems. But when LV network automation level increases then the information gathered from the distribution network will increase remarkably. The information would no longer be managed with the present ICT systems, especially due to AMI (Advanced Metering Infrastructure), which will increase the number of monitored nodes significantly in the distribution network. In addition, in the Integris system the amount of the information will be even more than in AMI system. Therefore, the information must be processed and filtered at lower levels so only the information that is valuable is sent to the upper level systems. Therefore, also ICT systems need more intelligent solutions to deal with all the information in the future network.

The purpose of this thesis is to simulate different case studies in the LV network by using the RTDS (Real-Time Digital Simulator). First case study is the LV network monitoring. The basic idea of the LV network monitoring is to gather information from all over the network and send the data to the secondary substation database where the data is stored and further reported to SCADA (Supervisory Control And Data Acquisition) in control centre. Second case study is the LV network congestion management. The purpose of this case study is to control power flows and voltage level in the LV network by controlling distributed energy resources. Third case study is the LV network fault management where all kind of fault situations and dangerous circumstances are simulated in the LV network and the real-time information is sent to the secondary substation database.

Second chapter of this thesis deals with the present LV network in Finland. It represents the structure of the LV network, protection, faults and power quality in it. Third chapter is about common distributed energy resources that can be used in the LV network and how they affect to protection and power quality in the LV network. Fourth chapter is about the LV network automation. In the beginning of this chapter is defined the present state of the LV network automation. Remaining part of the chapter four deals with the state of the art automation in the LV network. The simulation environment and the devices used in the RTDS laboratory are represented in chapter five. Chapter six and seven describes what kinds of use cases were simulated, how the simulations were carried out and the simulation results.

2 LOW VOLTAGE NETWORK

The LV network is part of the distribution network system. The purpose of the distribution system is to transfer electricity power from primary substation or power plants installed in the distribution network to the customers at the end of the network. The distribution system consists of primary substation for HV (High Voltage)/MV (110/20 kV, 45/20 kV) transformation, MV network (20 kV), secondary substation for MV/LV (20/0.4 kV) transformation and LV network (1 kV, 0.4 kV). There are currently around 800 primary substations, 150 000 km MV lines, 100 000 secondary substations and 200 000 km LV lines in the Finnish electricity distribution system. Most of the MV network lines are overhead lines and in the LV network they are either overhead (cable, AMKA) lines or cables. [1]

Distribution network is usually operated radial although it is built as a meshed network due the reliability reasons. Short-circuit currents are smaller and voltage adjustment and protection planning is easier in radial built networks. Meshed network enables backup connections in fault situations and it lowers energy losses. [1]

2.1 Structure of low voltage network

The LV network transfers electricity from secondary substations to the customers. Voltage level of typical LV network in Finland is 0.4 kV. Sometimes also 1 kV LV networks are built in sparsely populated areas in order to decrease losses and voltage drop on extremely long (several kilometers) LV lines. [1]

In Europe, the LV network typically has three phase conductors and a neutral conductor. Neutral conductor is for returning currents. Loads connected to the LV network are fed either with one phase or with three phases. Most of the loads in Finland are fed with three phases because of the high power consumption. In addition, long transferring distances in Finland forces to use all three phases to transfer electricity power especially in sparsely populated areas. Using only one phase would cause too much power losses in power transferring. [1]

The structure of urban and sparsely populated area LV networks differ much from each other. They have different amount of customers and thus different load profiles. In urban areas, LV network is built with high housing density and therefore have numerous customers. Adjacent transforming districts are built very near each other or sometimes they are even interlocked. There are often properties that could be electrified from both transforming districts with the same costs. In such areas, LV networks fed by different substations are often built in one to enable backup connections. It is advantageous to build the LV network so strong that in transformer faults they could feed neighbour transforming districts. However, using meshed LV network is very rare in Finland. LV network is usually operated radial and it has only one feeding point. Operating radial makes the LV network protection implementation easier because fault currents travel in one direction only. [1] Figure 2.1 represents the typical LV network structure in Finland.

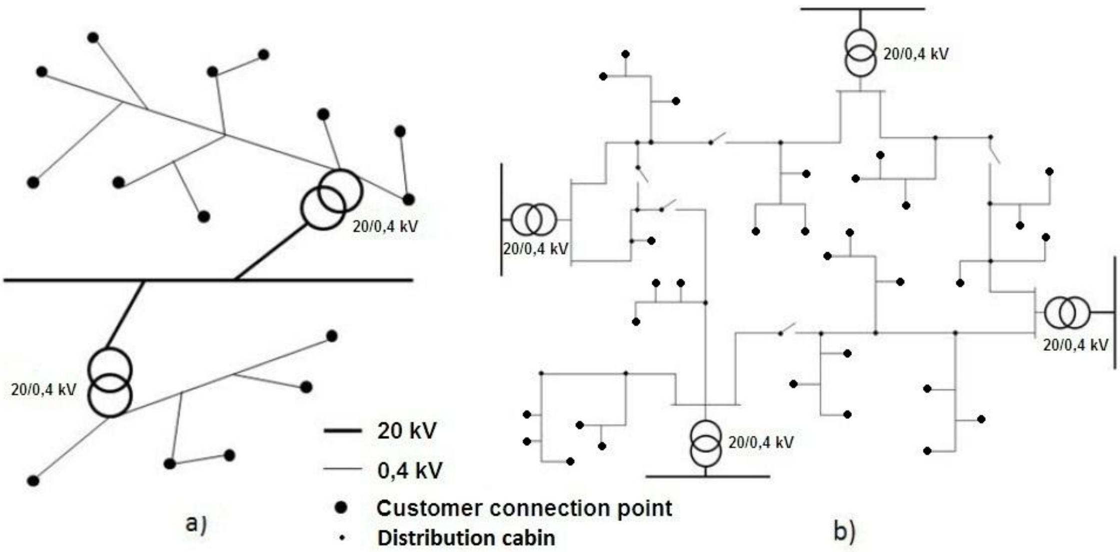


Figure 2.1. *Structure of LV network in Finland in a) sparsely populated areas b) urban areas. [2, applied]*

In sparsely populated areas the LV networks are built and operated radial and there are often wide uninhabited territories between transforming districts. Transforming districts have fewer customers than in urban areas and therefore line faults influence only one or few customers. In these kinds of circumstances it is not reasonable to use meshed networks to improve network reliability. Typically, building radial branches from the main line is the most economical way to build the LV network. Sometimes, when customer has a load with rapid current changes (e.g. welding machine) it is recommended to feed that customer with own line from substation. [1]

2.2 Secondary distribution substation

Secondary distribution substation is utilized to transform voltage level from medium voltage (20 kV) to the low voltage level (0.4 kV). Secondary substations can be divided into two different substations: pole mounted and building substations. The most common type of substation in Finland is pole mounted substation. Over 80 % of secondary substations in Finland are pole mounted substations. The purchase price of pole mounted substation is much cheaper than building substation. Building substations are not so vulnerable for faults caused by weather or animals because all the components are inside the building. Therefore building substations improve reliability of the LV network. Short circuit and overloading protection of the LV network is installed into substations. [1] Pictures of typical secondary distribution substations are presented in figure 2.2.

Figure 2.2. *Secondary distribution substations. Pole mounted substation [3] on left and building substation on right.*

Secondary distribution substation consists of MV busbar, one or more transformers and LV feeders. Spark gap and metal oxide overvoltage protection is utilized in pole mounted substations. Typical nominal power values for pole mounted substations are 50 and 100 kVA. Building substations are equipped with breakers, which are often used on the LV side, and nominal power value for building substation is 1000 kVA. [1]

In urban areas, high loads and high density housing forces to use cables and building substations. In addition, power consumption is much higher in urban areas so it is not possible to use pole mounted substations. Distribution cabins are used in urban areas to distribute cables to different customers. There are often back up connections between distribution cabins and therefore it is possible to redirect power feeding in fault situations. [1]

2.3 Low voltage network protection

It is not usual to use as powerful and expensive protection in the LV network as in the MV network. That is because using same protection in the LV network has not been considered economical. Therefore, typical fault current protection device used in the LV network is fuse and it is placed in every phase of the distribution substation feeder. It is scaled so that it withstands normal load current but works fast enough also when there is a one-phase short circuit at the end of the network. If those requirements are hard to fulfil then it is possible to use secondary fuses or larger conductors. Secondary fuses are selected so that they have smaller nominal current value than the fuses in substations LV feeders. If secondary fuses are properly scaled they allow selective separation of faults and fault at the end part of the network branch does not have impact on the beginning part of the network. The LV network protection system is presented in figure 2.3. [1]

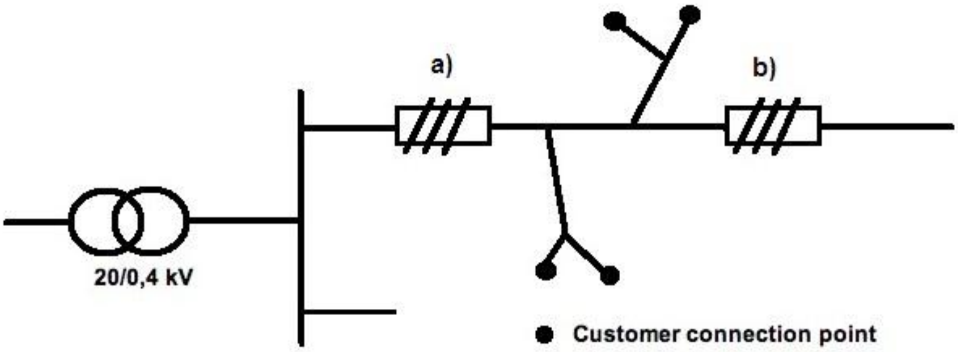


Figure 2.3. *The regular LV network protection system. a) feeder fuse b) secondary fuse [1, applied]*

Among the protection of the components of the network it is also very important to eliminate life and fire risks in the LV network. The minimum safety distances in the LV network are much smaller than in MV network. In addition, touch voltages are life-threatening in the LV network and conductors might cause risks for fire vulnerable constructions. Therefore, proper protection in the LV network is very important to avoid accidents. According to electricity safety act 410/1996 5§, the distribution networks should be designed and manufactured in such manner that they are not hazardous to life, health or property. Practically, this means proper grounding system along with the fuse protection. Grounding provides a low resistance return path for earth faults, which protects both personnel and equipment. The idea of the grounding system is to eliminate dangerous touch voltages. [1]

2.3.1 Low voltage network grounding

There are three types of grounding systems: TN-, TT-, and IT-system. TN-system can be divided into three types, TN-C-, TN-S-, TN-C-S-system, based on the fact that the neutral and protective conductors are separated or combined. Figure 2.4 represents different grounding systems. Used abbreviations have different meanings. The first letter describes grounded system of power-feeding electricity source. The second letter describes grounded system of exposed conductible parts of electrical installation. Further letters describe an arrangement of neutral and protective conductors.

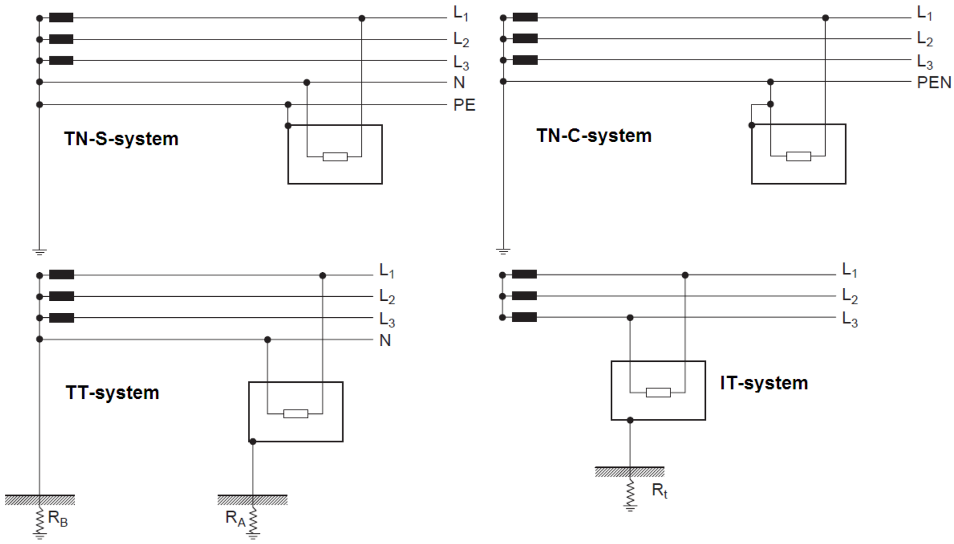


Figure 2.4. *Different grounding systems in the LV networks. [4, applied]*

The LV network in Finland is executed in TN-C-system and typical network at the customer point is executed in TN-S-system (at least at the newest households). In TN-C-system, the neutral and protective earth conductor combines in a single conductor throughout and in TN-S-system they are separated. All exposed conductive parts are connected to the PEN-conductor. PEN-conductor must be grounded from the feeding point or 200 meters from it at the most. In addition, over 200 meter lines or branch line must be grounded from the end of the line or 200 meters from it at the most. Grounding for AMKA cables should be done at least every 500 meters to enable overvoltage protection. Grounding is also suggested to do in every distribution cabin in cablified networks. In difficult grounding conditions grounding must be done for every branch line. Over 200 meters branch line could be built without separate grounding if grounding in every connection point is done properly. However, this is not desirable because grounding in every connection point could not be fully ensured. Implementation of transforming district grounding is presented in figure 2.5. [1]

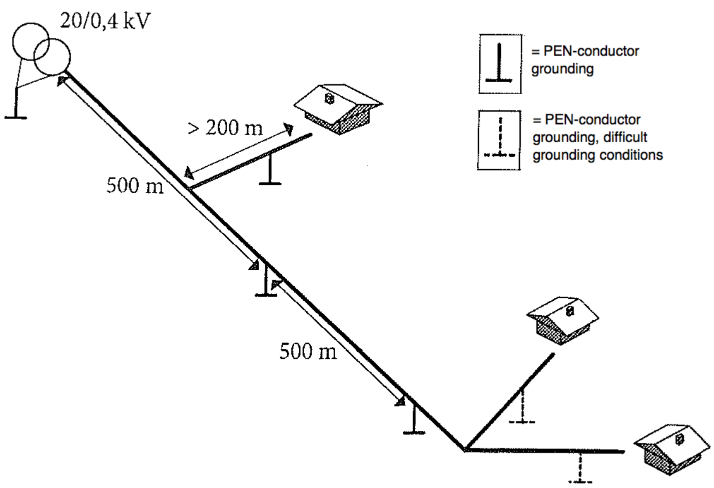


Figure 2.5. *LV network grounding in normal and difficult conditions. [1, applied]*

2.4 Dimensioning of distribution substation and low voltage network

Dimensioning of distribution substation is based on the LV network loading that the substation is feeding. The size and variation of the loading is usually available in the network information system and it is utilized for calculating the maximum power in the LV network. After finding the maximum power of the network it is possible to evaluate the loading capacity of the distribution substation. In addition, in distribution substation selection it is profitable to evaluate how much the consumption in that area is going to increase in the future. [1]

The main principle of the LV network dimensioning is to select right kind of conductor in a way that the total costs of the network would be as small as possible. In addition, the selected conductors must fulfil the technical requirements, which are the loading capacity, maximum allowed voltage drop and short-circuit withstand of the conductor. The LV network conductors are selected in a way that the voltage must not drop too much and the conductors must not overheat during the distribution. The LV network must also fulfil electrical safety requirements for the network protection. [1]

2.5 Faults and fault management in low voltage network

Faults in the LV network can be divided into two different types, ones that cause interruptions in distribution and ones that endanger electrical safety. In practise, phase faults caused by the blown fuse are the faults causing interruption in distribution. For example, approximately 76 % of all LV network faults in the network of Elenia Verkko Oy are faults were one or two phases are broken [5].

Neutral conductor fault is the most dangerous fault that endangers electrical safety. When neutral conductor breaks, return current looks for alternative way and therefore electrical devices could be exposed to overvoltage. Neutral conductor fault can also be life-threatening because the outer shells of electrical devices might become alive. Today the neutral conductor fault detection is based on customer’s notification. When neutral conductor fault is detected, distribution of electricity should be interrupted as soon as possible to ensure safety. [2]

The type of the network has impact on the number of the faults in the LV network. Faults occur more often in the overhead lines than in the cables. Fallen trees are the main reason in overhead line faults. Fallen trees cause 20-30 % of the faults per year in the network of the Koillis-Satakunnan Sähkö [6]. Benefits of cabling can be seen especially in major disturbances when there are lots of faults in the network at the same time. In worst case, it might take several days to repair the network and it takes a lot of fault repairing capacity. In cablified networks, faults do not usually occur at the same time and therefore it does not take so much repairing capacity. [2]

Fault reparation is the most important part of the fault management in LV network. Faults in the LV network are usually cleared by blown fuse and therefore the control centre receives no direct information on these faults. That is why most of the LV network fault reports come directly from customer. However, some of the faults might be detected during maintenance. Fault reports are directed either to fault service or in some cases to the control centre. After fault reports are received they are sent to fault reparation work group, which will repair the faulted part of the network. [2]

Accuracy of the information about the fault type and location affects the length of the repairing time. Because most of the LV network fault information is based on customer notification, finding the faulted area might take a long time. Finding the fault in overhead lines is possible by visual examination but in cablified areas it is not so easy. Cable fault locating radar is utilized in finding faults in cablified LV network. However, most of the cablified area faults are caused by careless ground digging and therefore they can be easily located. Back-up connections are usually used in cablified networks to reduce the fault time. [2]

2.6 Power quality in low voltage network

Power quality is very significant factor in the LV network. Customers demand for high quality power and supply voltage requirements set by standards force electricity distribution companies to invest in the quality of power. Supply voltage quality is evaluated based on the measurements from customer connection point. Supply voltage quality requirements in the LV network are set in the SFS-EN 50160 standard to ensure sufficiently good quality in the LV network. Standard defines main characteristics for supply voltage requirements in the LV network in normal conditions. It is not possible to set strict requirements for every supply voltage properties and therefore some of the properties have only recommended values. In addition, it is not desirable to set too strict requirements because it makes total costs of distribution network too high.

Measurable power quantities in the LV network are for example frequency, voltage level, rapid voltage changes, voltage dips and swells, harmonics and voltage unbalance. Table 2.1 represents quality requirements for supply voltage in the LV network according to standard SFS-EN 50160.

Table 2.1. *Power quality requirements in the LV network. [7]*

	Voltage characteristics according to SFS-EN 50160
Power frequency	50 Hz ± 1 % during 99,5 % of a year
Supply voltage variations	±10 % for 95 % of week mean 10 minutes r.m.s values
Rapid voltage changes and flicker	$P_{lt} \leq 1$ for 95 % of week
Supply voltage dips and swells	The dip threshold is equal to 90 % of the reference voltage The swell threshold is equal to 110 % of the reference voltage
Harmonic voltage	$3^{rd} \leq 5$ %, $5^{th} \leq 6$ %, $7^{th} \leq 5$ %, $9^{th} \leq 1{,}5$ %, $11^{th} \leq 3{,}5$ % THD ≤ 8 % of week mean 10 minutes r.m.s values
Supply voltage unbalance	During each period of one week, 95 % of the 10 min mean r.m.s. values of the negative phase sequence component of the supply voltage shall be within the range 0 % to 2 % of the positive phase sequence component.

The supply reliability is evaluated based on duration of interruption and the size of the interrupted area. Interruption is defined as a situation where supply voltage is less than one percentage of the normal supply voltage level. Interruptions are divided into planned interruptions and fault interruptions. Fault interruptions can be divided into short and long interruptions. Short interruption lasts under three minutes and it is caused by transient fault. Long interruption lasts over three minutes and it is caused by permanent fault. [7]

3 DISTRIBUTED ENERGY RESOURCES IN LOW VOLTAGE NETWORK

Smart grid has become the development trend in the future distribution network and distributed energy resources are a very important aspect of smart grid. They are integrated systems that can include distributed generation, energy storages and controllable loads. Benefits of distributed energy resources are improved power quality and reliability. Some of the reasons for utilizing distributed energy resources in the future LV network are increased power consumption and reducing emissions because most of the distributed energy is produced by renewable energy resources. Also transferring fees will be lower when power generation and consumption are near to each other. The aim is to provide inexpensive and reliable energy in the future.

3.1 Distributed generation and energy storages

Distributed generation units are small energy systems located in or near the place where energy is used. Examples of advanced solutions for distributed generation are solar energy applications and wind energy. Integration of distributed generation into the LV network can result several benefits. These benefits include reduced amount of energy lost in distribution, reduced environmental impacts, peak load shaving, increased overall energy efficiency, relieved distribution congestion, voltage support and better quality of supply at lower costs. [8,9]

The amount of available energy from distributed generation is often variable and difficult to predict. For example, on rainy and cloudy days solar panels will produce only small amounts of energy and when there is no wind there is no wind power production. Therefore energy storages could be used to balance the consumption when the load is high. At the present time energy storages for electricity are not generally used in LV networks because it has not been economically profitable. It is predicted that the storage capacity of energy storages will increase substantially in the next 20 years and therefore their use in the future will be profitable. [9,10]

There will be more distributed generation and energy storages in the future that are connected to the LV network. Smaller units of generation around the network are replacing traditional centralized units. Distributed generation and energy storages can provide good opportunities for the development of energy efficiency in the future. Effective use of distributed generation and energy storages requires two-way power flows, precise and real-time energy measurements and reliable two-way data transmission connections inside the grid. In the future the LV network is going to change from passive to active network and this means that the planning and use of LV network is going to be more complex. Therefore it will require more coordinated network operation and automation in the future LV network. Automated meter reading (AMR) is becoming more common and therefore it will provide new opportunities for utilization of distributed energy resources. [10,11]

3.2 Controllable loads

Controllable loads can be used to reduce the consumption in peak load situations and in voltage problems in the LV network. They are also used when customer wants to divide the use of loads depending on the price of electricity. Electricity price is typically lower at night and therefore it is affordable to use electrical devices during the night time. Typical controllable loads such as electric heating system, water heater and sauna stove have relatively high load and they are easy to control. Controlling an individual load will not give great benefits but controlling multiple loads on a large scale may give notable financial benefits. For example, successful peak load reduction may save the electricity distribution company from expensive investments to the network which is typically needed during few hours per year. [11]

The number of controllable loads will increase in the future and therefore they require more intelligent and flexible solutions. The new advanced AMR and controlling systems provide more versatile load controlling possibilities. Advanced controlling system allows controlling the loads much more efficiently and based on real-time signals. Load controlling combined with services enabled by building automation gives much more energy efficient use of controllable loads such as electric heating system and air conditioning. [11]

3.3 Impact of distributed energy resources on low voltage network

Penetration of the distributed generation is inevitably changing the structure and dynamics of the LV network. Distributed generation unit may reduce the investments of the LV network if the production unit is installed near to the load concentration or if it has production or load that is controllable. These things release the capacity of the feeder and investments to the LV network is not necessary. However, if the distributed generation unit causes voltage problems (voltage rise or rapid voltage changes), the LV network may need a new distribution substation and renovation of the network. These will increase the investments of the LV network. The type of the distributed generation unit has an effect to the power quality, fault currents and controlling solutions of the LV network. [12,13]

Traditionally LV networks have been designed to operate radially so that the electric power is fed only one direction from primary substation to consumption point. This has enabled relatively simple protection solutions. For example, in short-circuit faults it has been assumed that the fault current can have only one direction. However, penetration of distributed generation in to the LV network makes the fault current to flow in more than one direction in short-circuit fault situations and it also increases the magnitude of the fault current. As the share of distributed generation increases, LV networks are becoming more like transmission networks and more complex protection solutions are needed. Distributed generation also has an effect on power quality. Particularly in sparsely populated areas where the network is technically weak the power quality may be a problem. In urban areas where the network is technically strong the power quality rarely is a problem. [12,13]

3.3.1 Impact on low voltage network protection

Distributed generation unit in LV network might slow down the detection of the fault or even make the fault undetected if the feeder fuse settings are not checked. This sensitivity problem is possible when distributed generation unit is installed downwards from the protective fuse in LV network. It may cause severe safety problems and overheating of the network's components. [14] Sensitivity problem is often called protection blinding and it is shown in the figure 3.1.

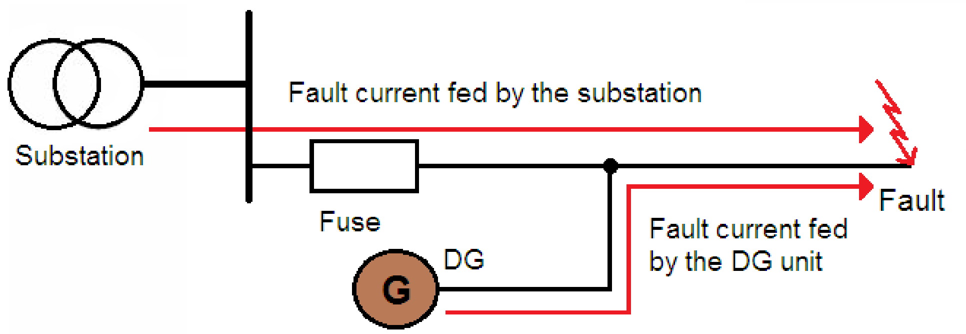


Figure 3.1. *The blinding of the protection.*

Blinding of protection occurs when distributed generation unit and substation are feeding the fault current in parallel. Fault current fed by the substation may reduce when distributed generation unit is also feeding fault current to the fault point. Therefore, the fault current going through the fuse is reduced and it will increase the operation time of the fuse or even prevent it from operating. Distance of the distributed generation unit from the substation, type of the distributed generation unit and the location of the fault has high impact on probability of the problem. Synchronous machines can produce great fault current for a long time and asynchronous machines can produce great fault current for a short time. If distributed generation unit is far from the substation then the probability of the problem is very high. This problem could be solved with using secondary fuses near the distributed generation but it might cause non-selective operation of the fuses. If the secondary fuse is same size as the feeder fuse, it is not selective and if it is smaller it may not withstand the load current. [14]

Another problematic situation in LV network protection is false tripping of the fuse that is shown in the figure 3.2. Distributed generation unit may cause unnecessary disconnection of the healthy feeder. False tripping is typically caused by synchronous generators located close to substation, which are capable of feeding sustained short-circuit current. [14]

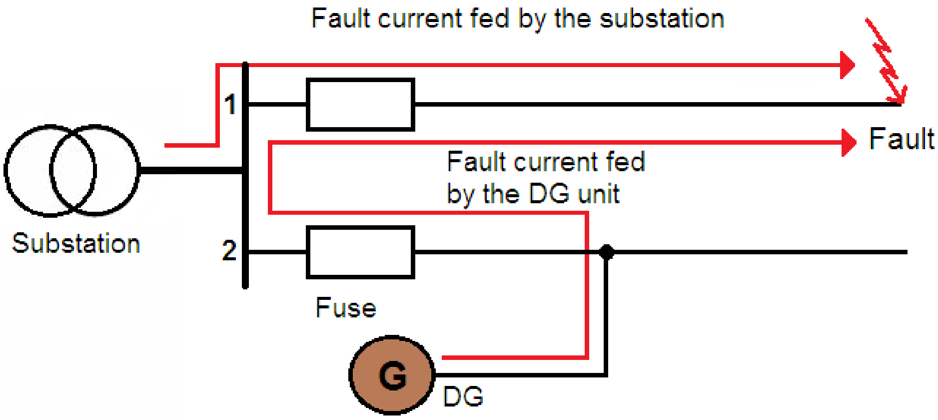


Figure 3.2. *The false tripping.*

When a short-circuit fault occurs in another feeder that is fed from the same substation than the feeder that has distributed generation, it might disturb the operation of the fuse. Distributed generation unit feeds fault current upwards towards the substation and further towards the fault point in feeder one. Therefore, when a short-circuit fault occurs on feeder one, also feeder two is tripped if the fault current exceeds the feeder two fuse threshold. A way to prevent false tripping could be directional overcurrent relay that measures the direction of the current. It will trip if the current flows to the wrong direction. However, directional overcurrent relays are too expensive to use in LV network and therefore it is more profitable to use traditional fuses. [14]

Unintended islanding operation may also occur in the LV network that has distributed generation units. It is a situation where the production unit is feeding a part of the network alone without connection to the main grid. Unintended islanding must always be prevented because it will cause dangerous safety problems to the personnel working on the network. Distributed generation units are also not planned for operating the network in island and they are not able to maintain an adequate level of power quality during the islanding operation. It may cause high voltage changes and it may cause damage to the network equipment. Therefore, distributed generation units should be equipped with protection that could prevent the islanding operation. In the present situation the conventional technique is based on the speed of frequency, voltage relays and frequency relays. [14,15]

3.3.2 Impact on distribution power quality

Distributed generation unit has an impact to the power quality of the LV network. It may improve or reduce the power quality of the LV network. Typically, the distributed generation unit decreases the voltage drop in the LV network and thereby improves the voltage level of the LV network. However, distributed generation unit may raise the voltage level of the LV network near the point where it is installed. Depending on the load of the network and the power of the production unit the voltage level might get to a very high level and it may cause damage to the network equipment. [15]

Distributed generation unit may also generate rapid voltage changes in the LV network. The start of the production unit and the disconnection from the LV network may cause these kinds of problems. The type of the production unit has a high effect on generated rapid voltage changes. Synchronous generators may cause high rapid voltage changes but modern production unit equipped with inverters has very little impact on LV network voltage levels. [15]

If the production unit has very variable production, it may cause flickering in the LV network. Especially wind power has very variable production because of the variable wind conditions. Also rapid connections and disconnections of the production units in the LV network may cause flickering. [15]

4 LOW VOLTAGE NETWORK AUTOMATION

Today the real-time information about the distribution network state is mainly gathered from the primary substation and the MV network and therefore distribution network automation has been focused on the MV network. Continuous monitoring at LV network level has formerly been rare and automation in the LV network has not been needed. This is because the automation in MV network has been much more important to the distribution network reliability than LV network automation.

In recent years, however, installation of smart meters has increased the amount of automation in the LV network. Also, the amount of distributed energy resources in the LV network is going to increase and therefore it forces to invest to the LV network automation. Power quality requirements and supply interruption costs are increasing in the future and they also call for more automated LV networks. Home automation level is also increasing in the LV network. Households may have their own electricity production such as solar panels and small wind turbines and controllable loads such as water heaters and electric vehicles. Automation might be used to manage for example voltage level fluctuation, effective utilization of own production and utilization of cheap electricity price. These are the main factors why the importance of LV network is increasing rapidly in the distribution network and therefore more intelligent solutions are required.

Changing the LV network automation to a more intelligent system is challenging but it provides many possibilities in the future LV network. AMR meters and substation metering devices which are part of the AMI, are good example of that. They can be utilized to improve LV network management such as power quality, load flow and fault management. Other examples are controllable loads and distributed generation in households that can be utilized in peak load management. They provide a good way to reduce the need of electricity power from the distribution network.

4.1 Advanced metering infrastructure

The AMI system covers all smart meters at the customer connection points, metering devices at the distribution substation and IT and communication infrastructures in the LV network. It measures, collects and analyzes measurements in the LV network and interacts with AMR meters through communication infrastructure. AMI provides almost real-time information from every strategic point of the LV network and therefore it improves the LV network management, network planning and power quality monitoring. [16]

4.2 Distribution substation automation

Traditionally the automation level of distribution substation monitoring has been relatively low and the substation monitoring has been based on the measurements that have been manually measured from the substation. The main reason for the lack of automation in distribution substations has been the economic issues. However, in recent years the distribution substation automation costs has significantly reduced and at the same time, the technology of automation has improved. [2] Therefore, the electricity distribution companies have begun to research and develop the automation level in the distribution substation.

The development of the first generation distribution substation monitoring system started at 2002 by Vamp Ltd. Their monitoring system contained measurements of electrical quantities on the LV side of the transformer, load calculations of the transformer and registration of power quality abnormalities. [17]

The second generation distribution substation system was developed during 2007. The new monitoring system was based on the relay technology manufactured by Vamp Ltd. The main improvements were the indication of MV network earth faults and short circuit faults and the development of the communication between monitoring unit and the SCADA and DMS (Distribution Management System) systems in the control room. In the first generation distribution substation the communication was done via SMS and in the second generation substation it was replaced by IEC104 protocol and GPRS. [17]

Helen Electricity Network Ltd has made a pilot project of a comprehensive monitoring system for urban MV/LV substations. In the pilot system there were two types of distribution substations: remote monitored and remote controlled. Measurements and alarm functions were carried out with WIMO 6CP10 measurement and monitoring unit. Following measurements were measured with the WIMO 6CP10 unit: [17]

- Disturbance recording files
- Voltages 10 min averages
  - Voltage sags, depth, duration and time stamp
  - Voltage spikes, height, duration and time stamp
  - Voltage 10 min average alarm level (max,min) monitoring and alarm
- Hourly averages of active power
- Hourly averages of reactive power
- Phase currents, 10 min averages
- THD (2.. 15 harmonic) in each phase

Other functions of WIMO 6CP10 unit are:

- Measurement of the earth-fault current (MV side) and earth- fault indication
- Indication of MV short circuit by short-circuit indicators
- Measurement of the temperature of the transformer using Pt100 sensor

Figure 4.1 illustrates system diagram of the Helen Electricity Network substation automation pilot system.

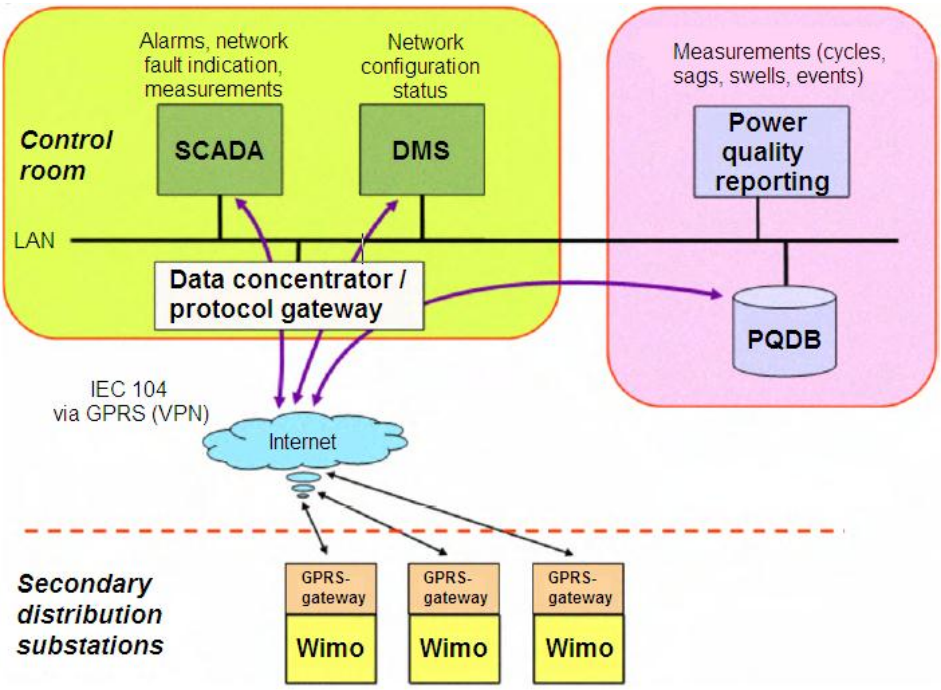


Figure 4.1. *System diagram of the distribution substation monitoring system. [17]*

The quantities are stored in permanent memory from which they can be read remotely and stored in to the measurement database in the control center. All the critical data, such as faults and transformer temperature alarms, are directed to SCADA system and the less critical data related to power quality, is stored in the power quality database.

Earlier mentioned automation system has mainly improved the MV network management, but not so much the LV network management. Installation of smart meters has enabled to increase the automation level of distribution substation and LV network management. In Integris project the main focus of distribution substation automation is in the LV network monitoring and management. [17]

4.3 AMR system

An AMR system consists of smart meters, communication system and data collection system. The primary role of AMR system has been to transfer energy consumption data from smart meters to a central database for billing and balance settlement purposes. Also some specific applications have been developed for load controlling in some installations. Traditionally the AMR and DMS system have been separate systems and in figure 4.2 is presented the traditional way of network management. [18]

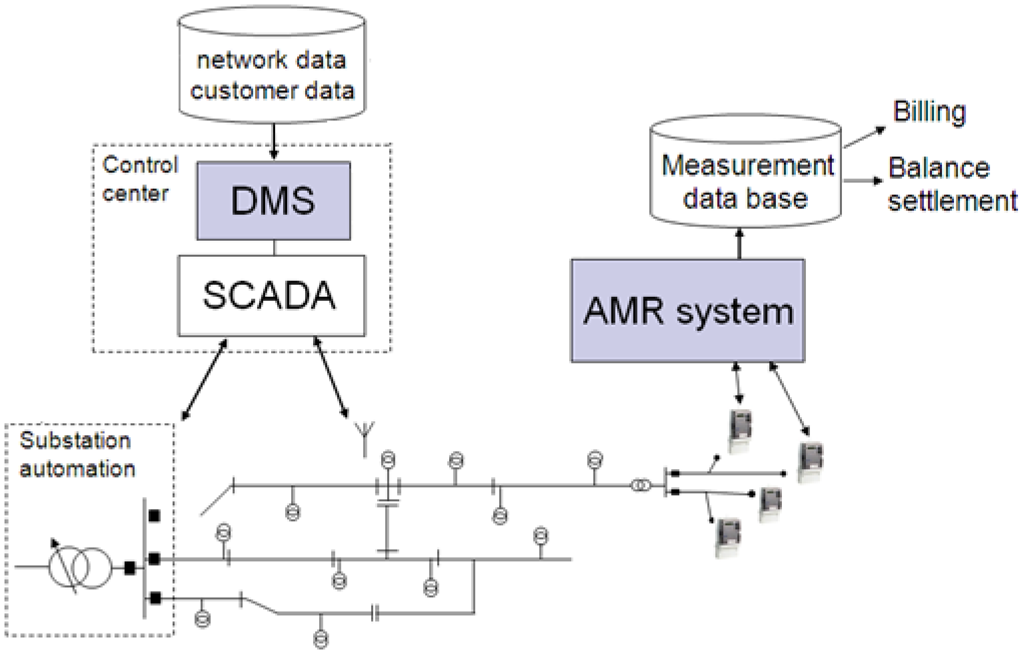


Figure 4.2. *Traditional way of network management. [18]*

In this kind of system the DMS has been used mostly for operating MV networks. AMR meters are integrated in the electrical network but they are not included in the network management. This kind of system mainly saves utility providers from sending workers to customer’s physical location to read a meter. In addition, the customer billing is based on near real-time consumption rather than on estimates based on previous consumptions. This information can help utility providers and customers to better control the use and production of electric energy. [5,18]

4.4 Advanced AMR system

The present AMR system enables using new upper-level functions and real-time two-way communication between customers and utilities. AMR system can be integrated with DMS and figure 4.3 illustrates how AMR system can be utilized for comprehensive network management in LV network. This will improve the network operation on the LV level. [16]

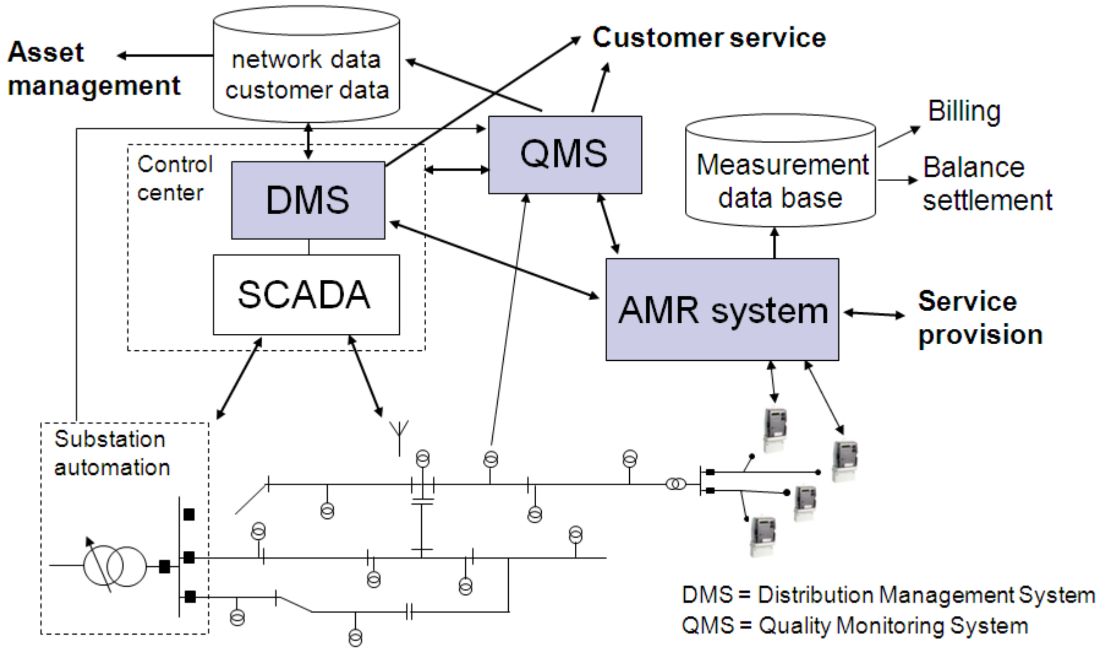


Figure 4.3. *Integrated system for comprehensive network management. [16]*

An advanced AMR system works as an intelligent monitoring device which provides vital information about the state of the LV network customer connection point. Real-time data can be utilized in many functions of distribution companies. The integrated AMR, DMS and power quality monitoring system can be used to support network operation, network planning, network state estimation, power quality monitoring, customer's service and load control in addition to traditional energy reading for customer billing and balance settlement. [18]

In Integris system the AMR system has been integrated as a part of the larger system. Integris system includes distribution substation metering devices, advanced AMR meters and communication network, which are used for advanced network management. Real-time measurement information from distribution substation and customer connection points in LV network is available in SCADA. A more detailed description of Integris system is presented in chapter five.

4.5 Utilizing AMI in low voltage network management

Comprehensive LV network management requires real-time information about the state of the LV network all the time. Together distribution substation automation and AMR system can provide this kind of information from the LV network. The AMI system provides accurately measured data and it enables better network state and fault management, power quality monitoring and network planning. Figure 4.4 represents the new functionalities in LV network that is utilizing AMI. [16]

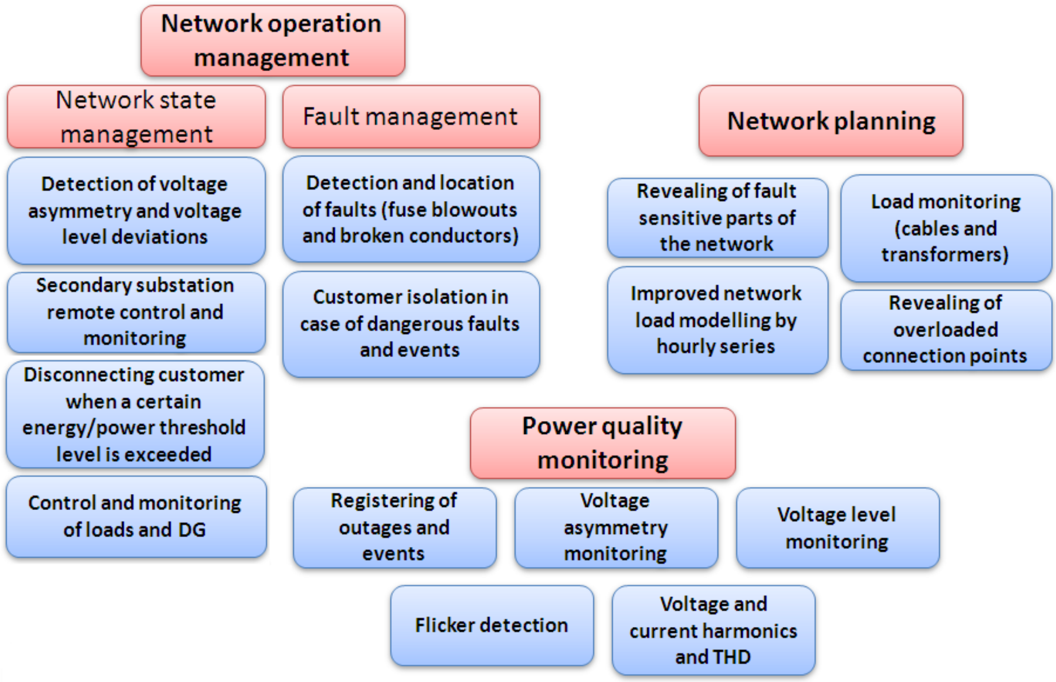


Figure 4.4. *Utilizing AMI in the LV network management. [16]*

4.5.1 Low voltage network state management

Network state management is used to achieve the most optimal use of the LV network. Traditionally, the state of the LV network has been based on network calculations and certain power quality reclamations because real-time information from the network has been very low. The AMI system enables almost real-time and accurate measurement data from the LV network and therefore it offers important information to be used in network state management. [16]

AMI can be utilized in load controlling functionalities. Momentary overloading is possible in the LV network because protection in the LV network allows exceeding of the nominal current without blowing the fuse immediately. If distribution substation is overloading then it is possible to remotely turn off customer's loads and decrease the loading peak in the network and prevent long-lasting overloading situations. To control customer's loads distribution companies have to make contract with the customer and agree in advance which loads and in what order they can be controlled. This functionality can be very important in the future, if the use of electrical vehicles will increase. Charging of electrical vehicles will increase the power needed from the network. Avoiding overloading situations will increase the lifetime of the LV network. [16]

At the customer level the load controlling may also be used to decrease the costs of the customer. For example, during the daytime when the price of the electricity is higher certain devices will be turned off and during night when the price is lower they will be turned on. It is also possible to set certain power limits to each customer and when the power consumption at the customer connection point is exceeded the AMR meter can automatically control certain loads of the customer. [16]

Another important control functionality is the remote disconnection of a distributed generation unit. Meters equipped with disconnection unit can be used to disconnect distributed generation unit when maintenance or fault repairing work is done in the network. Relays may also be used to disconnect distributed generation from the network. This will ensure safe working in the repair area. [16]

4.5.2 Low voltage network planning

Traditionally the LV network has not played critical role in the distribution network from the reliability point of view and the focus has been in the MV network. However, the LV network is the most expensive part of the distribution network and the most of the network losses in electricity distribution occurs in the LV network and secondary substation. Accurate measurement from AMI system provides valuable information from the LV network that can be used for the LV network planning. [16,19]

Information from AMI system provides more accurate load models for network calculations. It is usually assumed that the proportion of active and reactive power is constant but AMI system provides accurate active and reactive power values, which can be used in network calculations. With improved calculations the peak demand at each point of the LV network can be estimated more accurately, which allows correct network renovation investments. [16,19]

AMI system also provides good power quality information, which can be used to detect the weakest point of the LV network. It also reveals the most fault sensitive part of the LV network. This information can be used to reveal which part of the LV network and the components in it needs investments. [16,19]

4.5.3 Low voltage network power quality management

Comprehensive power quality management system requires extensive measurement data from the LV network. Today most of the power network measurements are from primary substation and measurements from customers are rare. Power quality measurements from customers are special cases where customer has ordered measurements for example because of bad power quality. [20]

Information about the quality of electricity in the LV network could be improved by installing special power quality meters to the customers. To get accurate power quality information about the LV network the measurements should be available from each connection point of the LV network. That means high investments for the network operator. The development of AMR meters has enabled new measurements from customers. Nowadays AMR metes have some basic power quality measurements, such as over and undervoltage and voltage asymmetry measurements, that can be utilized to monitor power quality in the LV network. [16,20]

In Finland the aim is that at least 80 % of the distribution network customers have remotely readable AMR meters at the end of year 2013. Therefore a large part of the distribution network will be provided with AMR meters. If each of these customer connection points would be equipped with AMR meters that have quality measurements then the power quality measurements covers a large part of the distribution network and power quality monitoring of the LV network would be significantly improved. AMR meters might have certain limits for the quality measurements and when the limit is exceeded it will send alarm about the voltage quality. Although AMR meters will not measure all the power quality measurements that can be used to analyse the LV network power quality, they allow basic power quality monitoring in LV network. [16]

4.5.4 Low voltage network fault management

Fault management in the LV network has been more difficult and time-consuming than in MV and HV networks and fault location methods in the LV network have been relatively low. However, the LV network can have a length of multiple times higher than MV and HV networks and in urban areas single fault can cause an interruption for many customers. The same fault location methods cannot be directly used than in MV and HV networks because there are lots of radial branches and many loads attached to these branches in the LV network. [2]

Advanced AMR meter can be utilized to detect missing phase voltages and other voltage abnormalities in the LV network. This information makes possible to reveal fuse blowouts, broken phase conductors and broken neutral conductors in the LV network. Alarms about these faults will be sent directly to the DMS system where complete network model (MV and LV networks) is available. Customers fuse blowouts can be detected from the AMR meter voltage measurements. Advanced DMS can also detect some of the faults by sending queries to the AMR meters. If DMS is unable to get answer to the query then there is an outage at that customer connection point. This is essentially a back-up tool for narrowing the faulted area and for checking if everything is working well after fault reparation. Broken neutral conductor can be detected from voltage asymmetry information and AMR meter with a specific disconnection unit can isolate the customer automatically from the LV network. Neutral conductor fault causes hazardous voltages and might damage electric devices and it is also dangerous to people using those devices. [16]

AMR meters can also been utilized in information about fault types and the duration of the fault. So far there has not been reliable information about the beginning of the fault. It has been based on the information from the customers. [16]

4.6 Home automation

The level of home automation has been increasing during the past decades. Home automation enables monitoring, demand response and other control functions needed for the LV network automation. Home automation systems can be utilized efficiently because they have good data processing and storing capabilities and communication to other systems is based on common standards. [21] One good example of home automation system is ThereGate home energy management device that is used in this thesis tests. More detailed description about ThereGate can be found from chapter five. Figure 4.5 represents a smart home model where lot of automation is installed.

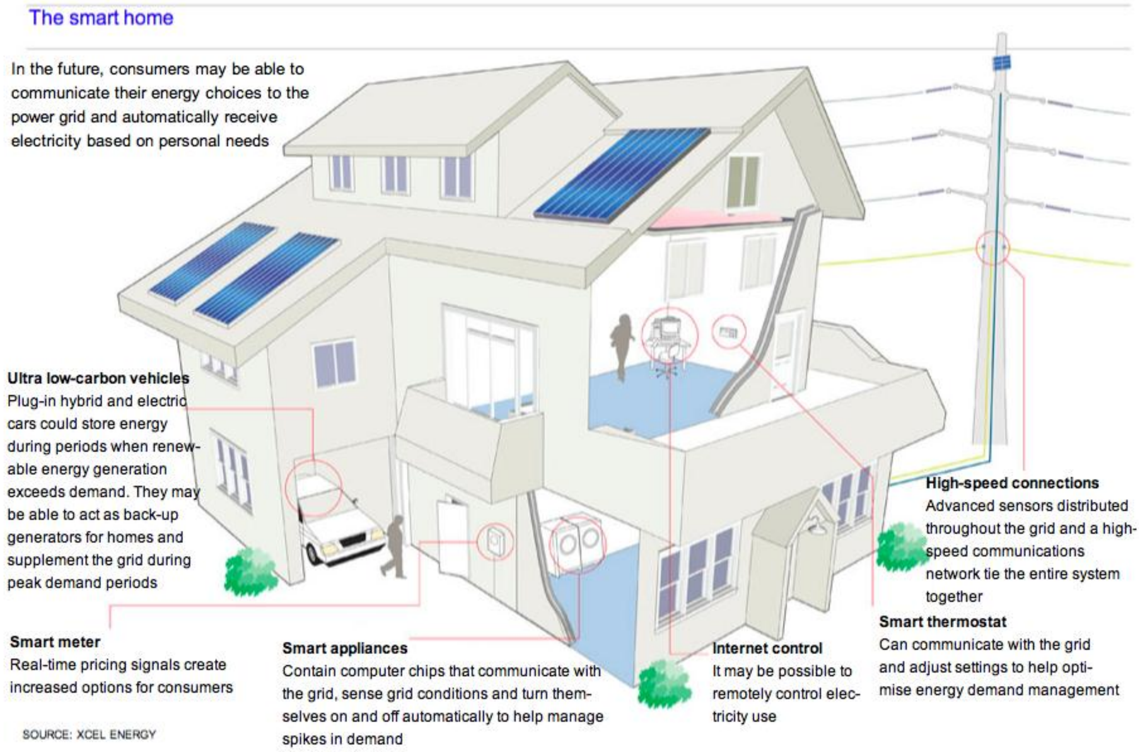


Figure 4.5. *A smart home model. [22]*

Customers in the LV network have limited power capacity in their connection point. If customer has many electrical devices that use lot of electricity there is a possibility that the maximum power limit can be exceeded. Controlling of customer’s loads is needed to avoid exceeding the power limit. Therefore, it is common that electric sauna stoves, space heaters and water heaters cannot be used at the same time. If sauna stove is turned on the space heater will turn off. It is important to monitor indoor temperature because especially during winter time the indoor temperature might get low if the space heater is turned off for a long time. However, usually timer in sauna stove will limit the time that stove is turned on and therefore the indoor temperature will not decrease too much. [21]

Home energy management systems with smart meter will help reduce energy consumption of a household. Bremen University of Applied Sciences has made a study during years 2002-2007 of KNX controlled installations versus traditional electrical installation. They installed part of their new informatics building with KNX network and metering system. KNX is an international building automation standard which can be used to improve the energy efficiency in households. KNX allows combining different vendors' products and functionalities. It is suitable for example for heating, lighting, air conditioning and security systems management. [23] The efficiency of KNX network and metering system can be seen in the figure 4.6.

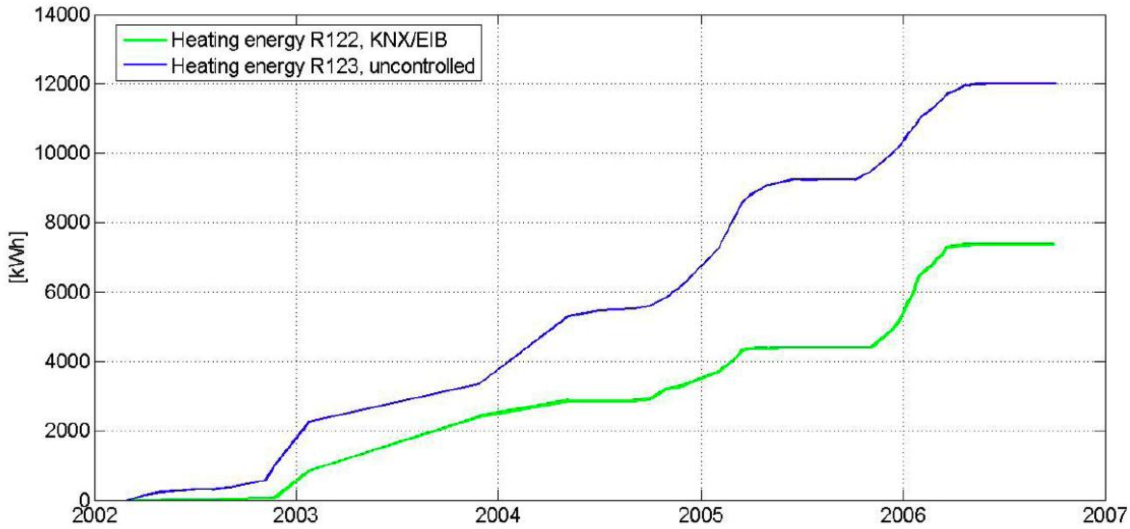


Figure 4.6. *Heating energy savings with controlled thermostats compared to traditional thermostats. [23]*

Utilizing KNX network and metering system reduced significantly the energy consumption. Almost half of the energy consumption was reduced with KNX controlled installations compared to traditional installations. Reducing energy consumption will also reduce energy costs. This can be achieved by proper integration and programming of home appliances to run during low tariff periods. Certain devices that consume large amounts of power can be adjusted to do much of their work during off-peak times when the price of the electricity is lower.

5 SETUP IN THE REAL-TIME DIGITAL SIMULATOR ENVIRONMENT

Study case simulations were made with the Real-Time Digital Simulator (RTDS), which is optimized for power system simulations. The RTDS simulator is designed to simulate electrical power systems and test physical equipment in real-time. Numerous analogue and digital input and output channels provide flexible interconnections with the simulator. [24] Signals from output channels can be amplified to real life voltage and current levels and in this case to the LV network level.

5.1 The low voltage network modelled in the RTDS laboratory

The LV network modelled in these simulations is part of the network of the Koillis-Satakunnan Sähkö and it is represented in Figure 5.1. The LV network has three phases and it consists of one MV/LV substation, fuses and seven customers with different load profiles. Customers may also have distributed generation, which might be controllable.

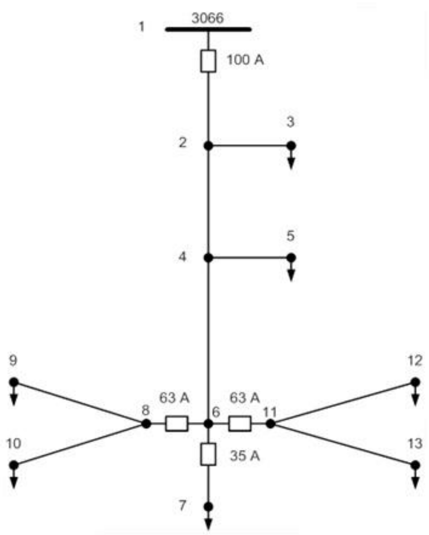


Figure 5.1. *The LV network modelled in simulation.*

Physical devices used in these simulations for customer measurements and data analysis were Kamstrup 382 and Emiel smart meters, Theregate home energy management device and MX Electrix power quality monitoring unit. Schneider Electric’s RTU (Remote Terminal Unit) was used for substation measurements. Figure 5.2 represents logical connections of all the devices and components used in these simulations.

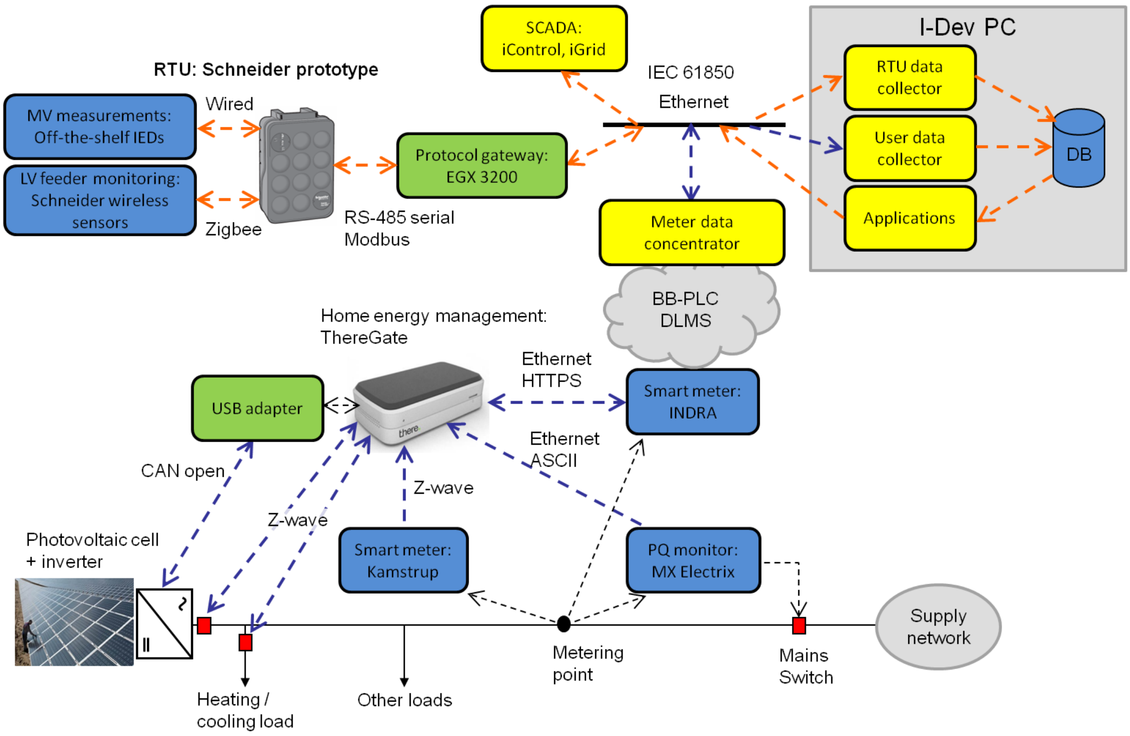


Figure 5.2. *Logical connections of devices and components. [25]*

Amplified voltage and current values for each phase were sent from the RTDS to smart meters and RTU unit by using two amplifiers. Those voltage and current values were calculated from certain active and reactive power values that were based on real-life measurements. Every customer has a different load profile and figures of the load models can be found from appendix one. One of those customer measurements has one-second accuracy and six other measurements were interpolated from ten-minute average values to one-second values. In RSCAD model it is not possible to use one-second values because it takes approximately seven seconds to set correct values to the simulator each time. Therefore, ten-second values were used in these simulations. Detailed information from the modelled LV network and customers can be found from appendix two.

Different devices communicate in different ways. The information from measurement sites is translated to IEC 61850 by using protocol gateways, so in that way Integris device (I-Dev) has only IEC 61850 interface. Protocol gateways are physical device that makes transformation automatically if they are properly programmed. RTU device has its own protocol gateway and transformation for customer information is done in user data collector in I-Dev PC. SCADA also needs its own protocol gateway if it is using something else than IEC 61850 standard. Smart meters use DLMS (Device Language Message Specification) protocol in communication, which enables the integration of energy meters with data management systems from other manufacturers.

5.2 Integris device PC

All the measurements from the LV network are aggregated and stored to I-Dev PC database, which is located in the secondary distribution substation. The database is part of the more comprehensive measurement database. All the measured data (e.g. state estimation, load flows, etc.) is stored and processed as near as possible to the measurement points. It is more reasonable to run algorithms in every LV networks own secondary substation than in control center. Therefore, only average measurement values and alarms from the LV network are sent to upper level systems. [25] In these test, one of the computers in the TUT laboratory was used as I-Dev PC. Information from RTU unit and smart meters were stored to this computer.

Network state estimation, congestion management and fault location Octave scripts were installed to the I-Dev PC. These scripts get measurement data from the I-Dev database. Network state estimation script estimates the voltage and current values for each customer all the time. In load congestion situations script will also determine where the overloading has been and a command to reduce load will be sent to the ThereGate unit. If any action is taken, ThereGate will answer back what activities it has taken to reduce the load. Fault location uses measurement data from database to detect the faulted area of the LV network.

5.3 SCADA

SCADA is a supervisor unit and it is installed in one of the computers in the TUT lab and it is used to monitor the grid in real-time. SCADA receives continuously measurements data and alarms from the I-Dev PC database. In these simulations iControl SCADA is used to gather important information from the LV network and to send commands to LV network devices, e.g. ThereGate and smart meters. Figure 5.3 represents the view in SCADA screen.

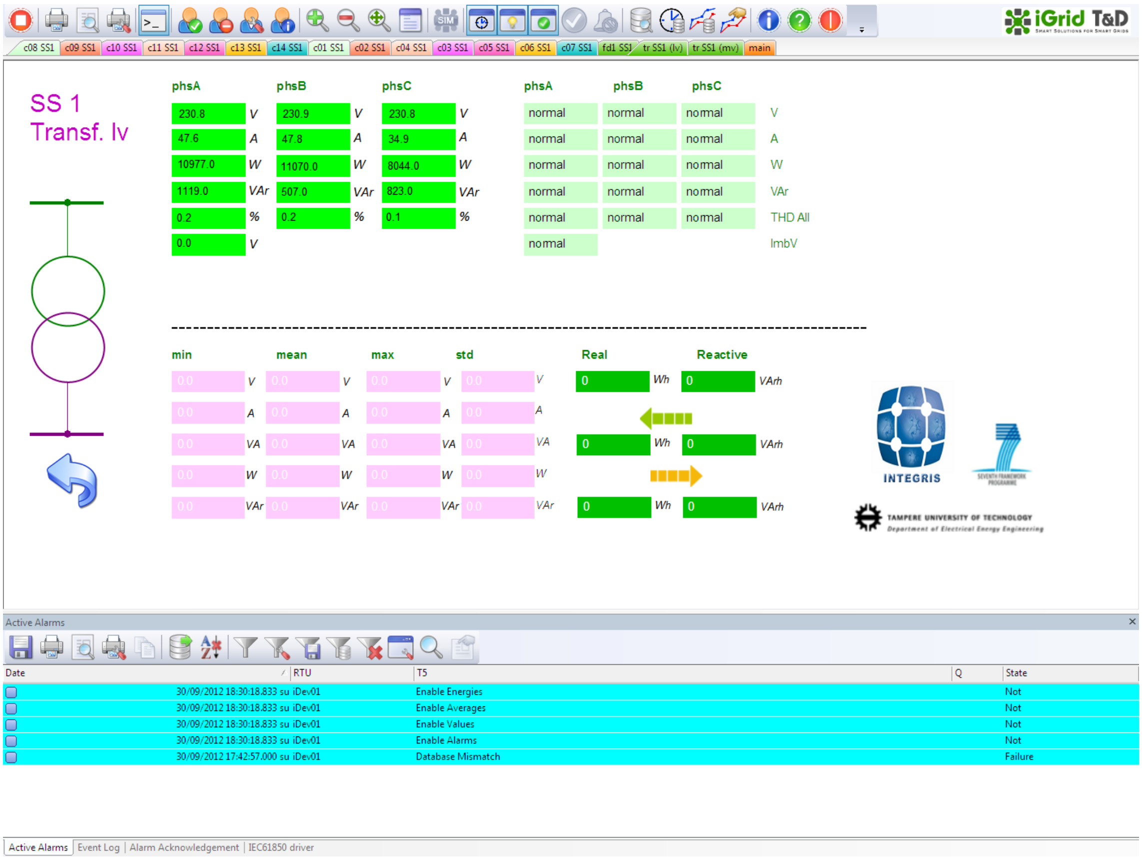


Figure 5.3. *Overview of SCADA system.*

In these simulations the MV network information was not measured and only information from the LV network was available. SCADA system represents a lot of information of the LV network and it is possible to set threshold levels for each measured quantity. Every customer has its own screen in the SCADA and there are also screens for LV and feeder measurements. From the main screen it is possible to see the structure of the network. Following measurements are shown in the SCADA screen:

- Voltage and current values for each phase
- Active and reactive power values for each phase
- Total harmonic voltage distortion for each phase
- Voltage asymmetry
- Positive real and reactive energy
- Negative real and reactive energy
- Min, max, mean and std values for voltage, current and power values
- SCADA also indicates if threshold level is exceeded

5.4 RTU

RTU is used to collect measurement data from secondary substation. It receives current values from both sides of the transformer and voltage values from the LV side of the network. In addition, it receives current and power quality, such as harmonics and unbalance, values from each LV feeder. Calculations are made within the sensors. Active and reactive powers are calculated as well as energy flows. Figure 5.4 represents the overview of RTU measurements in secondary substation.

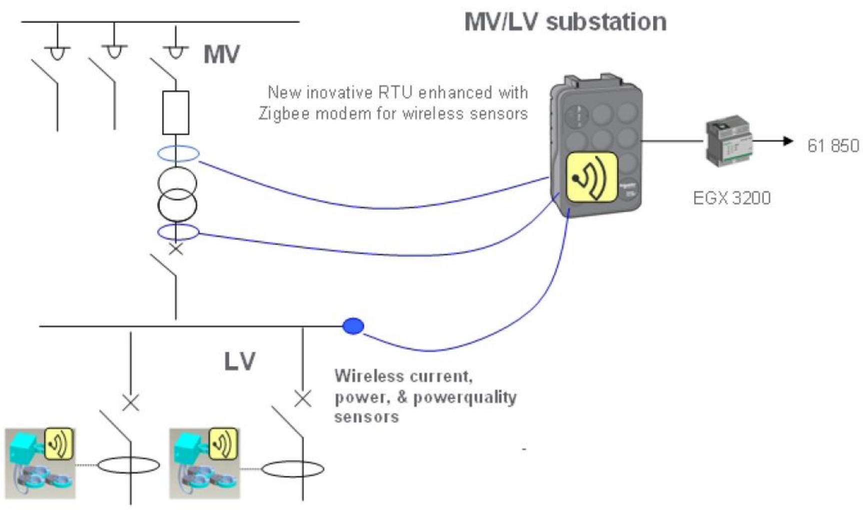


Figure 5.4. *The substation measurements arrangement. [25]*

Measurements from both sides of the transformer are sent by wired connections to RTU unit. Measurements from each LV feeder are sent wirelessly to the RTU unit. Aggregated information in RTU is sent through a gateway to RTU data collector and from there to I-Dev database. Schneider Electric’s EGX 3200 gateway is used to translate the information to IEC 61850. The RTU monitoring device used in this project is Schneider Electric’s Easergy Flair 200C substation monitoring unit, which is presented in figure 5.5.

Figure 5.5. *Flair 200C distribution substation monitoring device. [26]*

Easergy Flair 200C is a remote monitoring unit designed for distribution substations. It is an efficient tool for reducing fault location and repairing times and it improves quality of service and operation for power supply companies. The Flair 200C is specially designed to meet customers' requirements for the management of distribution substation. It provides compact, open solutions: [26]

- Fault passage indicator compatible with any type of earthing system.
- Substation monitoring: sending of an alarm in the event of an incident in the substation for efficient maintenance.
- Power monitoring unit on the MV and LV network for improved monitoring of load curves and improved power distribution efficiency.
- Substation digital concentrator for interfacing between the substation communicating equipment and the control centre.
- Communication with the remote control centre with call management upon alarm.

5.5 Smart meters and power quality monitoring unit

Two different kind of smart meters are used in these simulations. Kamstrup 382 and Emiel smart meters are used to measure values from customer end and Emiel smart meter is also used for aggregating information from home energy management device. Kamstrup 382 and Emiel smart meters measures phase voltages and currents, active and reactive power and energy values.

MX Electrix power quality monitoring unit was used in these simulations and it is connected to the customer connection point. Power quality monitoring unit measures such values as voltage level, rapid voltage changes and harmonics. After each 10-minute period it will produce power quality values and ThereGate will ask those values every 10-minute period. It also sends fault indication information in situations such as broken neutral conductor, outage and wrong phase order.

5.6 ThereGate home energy management

ThereGate home energy management device is used in this simulation. It is basically a smart wireless router, which communicates with the equipment at home such as sauna stove, electric heating system and water heater. ThereGate is running peak load reduction algorithm, which is needed to prevent overloading of the connection point when multiple high loads would be simultaneously on. If the capacity of the connection point is exceeded, algorithm turns off some loads and controls when each load is turned on. In addition, it can also receive information from the upper levels of the network management system that defines the maximum and minimum amount of load to be connected. Maximum connection point current or total load in kW is possible to set to the ThereGate. In figures 5.6 and 5.7 is presented one form of peak load reduction system. [21,25]

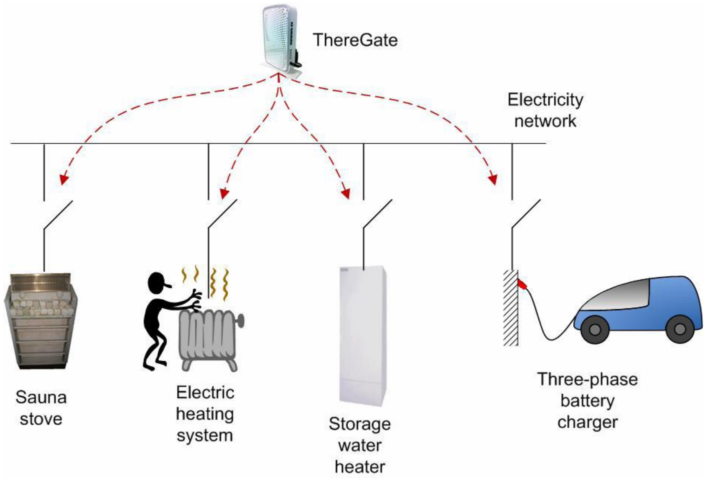


Figure 5.6. *The principle of peak load reduction system. [21]*

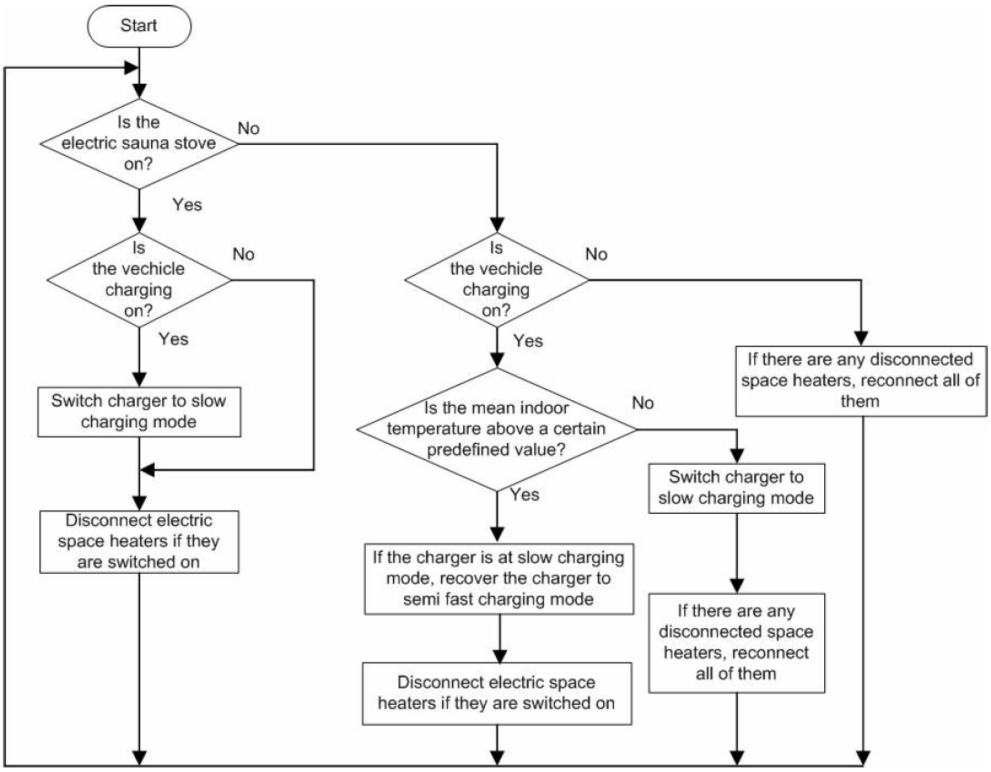


Figure 5.7. *Cyclic algorithm of the control actions in the peak load reduction scheme. [21]*

Peak load reduction algorithm includes alternator controller algorithm to control customer loads in situation where supply network capacity is limited. It divides different loads, prioritized by customer, into different time frames. Prioritization is used for deciding in which order and how long each load is supplied. Algorithm works so that it takes the highest priority load from the list, and if it fits to the load limit it adds it to the time frame. After that it takes the second load from the priority list and checks if it fits to the load limit. If it does not fit to the load limit, the algorithm checks the third load from the priority list. When it founds suitable load for the first timeframe, algorithm adds the load to the timeframe. Then it looks for suitable loads for the second timeframe that were not in the first timeframe. [21,25]

5.7 Time synchronization

Synchronization is already used in primary substation automation and it is based on GPS (Global Positioning System) based synchronization. In distributed measurement systems, like in this thesis simulation environment, the time synchronization is really important. In order to guarantee the synchronization of the different devices, the Control Centre will have an NTP (Network Time Protocol)-server that will distribute the synchronization. In TUT laboratory one of the computers is an NTP-server and other devices get their time from that computer. Exceptions are power quality meter and Indra’s smart meter. Power quality meter updates its clock based on ThereGate clock and Indra’s smart meter based on meter data collector.

6 USE CASES

There are three different use cases that are simulated in the RTDS environment. First use case is about LV network monitoring and two other use cases are about LV network congestion management and fault management. The idea of these simulations is to make different kinds of situations (e.g. rapid voltage changes, overloading, different faults and harmonics) to the LV network and test how different devices communicate with each other and how the whole LV network can be monitored and managed with the I-Dev PC and SCADA.

6.1 Low voltage network monitoring

The basic idea of the LV network monitoring is to gather important information from transformer, network and customer connection points. The aim of this use case is to check how I-Dev PC and SCADA perform in various LV network conditions. These various conditions maybe typical load or production changes during a day, fault situations and power quality events. It is also important to check that correct alarms and reports of these changes are generated. Electrical properties of the simulated network are varied by predefined load profiles. Also the averaging of measurements and the reading frequency of measurement information is varied to see how it affects to the measurement results. Main things to study in LV network monitoring: [27]

- How accurately the LV network monitoring performs.
- How changing of measurement average and reading frequency affects to measurement accuracy.
- How quickly information from RTU and smart meters is transferred to I-Dev PC database.

6.1.1 Metrics for monitoring

The monitoring of the LV network is tested with three different metrics that are listed below. These are divided into I-Dev accuracy and response time. [27]

1) *Accuracy*

First metric in LV network monitoring tells the ratio between events not seen by I-Dev and all events in the LV network. The idea of this metric is to test how accurately and how small changes I-Dev can see in the LV network. The equation for missing events ratio can be written as following:

$$Acc1 = \frac{n_{missing\ events}}{n_{events}} \tag{1}$$

Where n_{events} is the number of all events in the LV network and $n_{missing\ events}$ is the number of missed events by I-Dev.

Second metric tells the average RMS error of monitored quantities. The idea of this metric is to measure overall accuracy of monitoring use case influenced by averaging of quantities and measurement reading frequencies. RMS error is calculated for each monitored quantity received by I-Dev compared to real instantaneous values from the RSCAD simulator. The equation for average RMS error can be written as following:

$$Acc2 = \frac{1}{m}\sum_{i=1}^{m}\sqrt{\frac{1}{T}\sum_{t=1}^{T}(q_{\ mon,i}(t) - q_{event,i}\ (t))^2} \tag{2}$$

Where $q_{mon,i}$ is the monitored quantity, $q_{event,I}$ is the real instantaneous value, T is testing period and m is measurement points.

2) *Response time*

Third metric tells the average time delay to get information from the LV network to I-Dev database. Response time is calculated for both the RTU device and smart meters because devices have different reading frequency and communication system. The time delay is calculated by comparing the time when the query to meters is send and the time when database receives the measurement information. The equation for average time delay can be written as following:

$$RT1 = \frac{1}{m}\sum_{i=1}^{m}\left(t_{IDEV,i} - t_{event,i}\right) \tag{3}$$

Where $t_{event,i}$ is the timestamp when the query to meters is send, $t_{\mathrm{IDEV,i}}$ is the timestamp when the information was stored to I-Dev database and m is the number of measurement messages.

6.2 Low voltage network congestion management

The purpose of this case is to manage power flows and voltage levels in the LV network by controlling distributed energy resources and controllable loads. Smart meters and home energy management devices are utilized in controlling. Availability and size of the distributed energy resources are managed with home energy management unit. Indra’s smart meter is utilized for communication between I-Dev PC and home energy management unit. Home energy management unit aggregates information from distributed energy resources. The final decision of controlling is done in home energy management unit because the most recent information about distributed energy resources availability and controllability of each customer is in home energy management unit. State estimation and power flow and voltage management algorithms are installed in I-Dev PC and they are utilized in LV network congestion management. [25]

6.2.1 State estimation

The state estimation algorithm estimates currents, voltages and power flows in all phases and all parts of the LV network based on static network data and the real-time measurements in the database. Control center has complete model of the distribution network and it sends the information of the LV network and secondary substation, such as the network topology and electrical data of the network components and customers locations to I-Dev PC. State estimation improves the accuracy and reliability of the LV network state when real-time measurement information is unavailable from some of the customers or measurement quality is bad. It is also possible that measurement information is not wanted in real-time from every customer and state estimation is used to estimate those customers' measurements. This way the price of the control system is cheaper. [25]

State estimation has been implemented as an Octave function, which is based on a branch current method. It utilizes the magnitudes and phase angles of branch currents as state variables. State estimation algorithm calculates estimates for each phase and three-phase load estimates are used only if phase specific power measurements from smart meters are unavailable. In that case, the three-phase load is divided evenly to all phases. The state estimation algorithm used in these tests requires the following inputs: [25]

- LV network data (topology, line parameters and location and used phases of customers)
- Three-phase load estimates (from customer class load profiles)
- Secondary substation voltage measurement
- Phase specific power measurements from customers' smart meters
- Phase specific power or current measurements from substation RTU unit

State estimation gives best possible estimation of network state if above mentioned inputs are available and it gives node voltage, current and power flow estimates as output. Main things to study in state estimation: [25]

- How accurate estimations the state estimation algorithm can give when information from every customer is available and on the other hand when measurement information is not available from every customer.
- How it works when some of the measurements are erroneous.

- How forgetting of old measurement information affects to state estimation accuracy.
- How changing of measurement average and reading frequency affects to state estimation accuracy.

6.2.2 Load flow management

The load flow management algorithm has been built above the state estimation algorithm. Algorithm’s inputs are customers’ estimated voltage and current values from the state estimation and real measurements from the RTU unit. It also needs upper and lower limits for voltage levels and upper limit for current. Calculations of state estimation are compared to operational limits of secondary substation and the LV network. If some thresholds are exceeded I-Dev PC utilizes load flow management algorithm for searching distributed energy resources that could solve the problem. After finding suitable resources to control it sends control commands to selected home energy management units. The control commands includes following information: [25]

- What kind of control is expected (reduce or increase)
- How much control is needed
- Where the control should be realized

In overload problems the load flow management algorithm compares measured and estimated current values to predefined current thresholds. If the overload sub-function detects overload problem, it determines which customers are downstream from the fuse. Then it determines which customer needs to reduce its load and how much. [25]

In under and overvoltage problems the load flow management algorithm works almost the same way as in overload problem. If the undervoltage sub-function detects voltage problem it determines which customer needs to reduce its load and how much. If the overvoltage sub-function detects overvoltage problem it determines which customer needs to reduce its power generation or increase its loading to decrease the LV network voltage level. However, it is necessary to check if voltage problem is in the MV network. If voltage problem is in the MV network local control inside the LV network should not be done. Thus the LV network congestion management may need to be able to receive commands from the MV network congestion management. Main things to study in load flow management: [25]

- How fast the load flow management algorithm detects overload or voltage problem in the LV network.
- How fast it can remove the problem from the LV network.

6.2.3 Metrics for LV network congestion management

State estimation algorithm is tested in normal situations where every measurement point is available and in situations where only one or two measurement points are available. Also the impact of smart meter reading frequency, measurement averaging window, the impact of erroneous measurements and how long old measurement information is profitable to use in state estimation algorithm are tested. [27]

The load flow management is tested by examining if the power flow and voltage management algorithm can produce correct control commands in unwanted loading situations to avoid the LV network congestion. The LV network congestion management is divided into response time and value of state estimation and the metrics used in these tests are listed below. [27]

1) *Response time*

First metric in LV network congestion management tells the average time to detect LV network congestion. The equation for the time to detect the LV network load congestion can be written as following:

$$RT2 = \frac{1}{E}\sum_{i=1}^{E}\left(t_{detect,i} - t_{event,i}\right) \tag{4}$$

Where E is the number of events, $t_{detect,i}$ is the time of the load congestion detected by I-Dev and $t_{event,i}$ is the time when load congestion is done in RTDS simulation.

Second metric tells the average time to remove LV network congestion. The equation for the time to remove the LV network load congestion can be written as following:

$$RT3 = \frac{1}{E}\sum_{i=1}^{E}\left(t_{solved,i} - t_{detect,i}\right) \tag{5}$$

Where E is the number of events, $t_{detect,i}$ is the time of the load congestion detected by I-Dev and $t_{solved,i}$ is the time when load congestion is solved.

3) *Value of state estimation*

Third metric tells the average RMS errors of estimated quantities (voltage and current) with complete measurement setup. Idea of this metric is to test how accurately the state estimation works when measurements from every smart meter and RTU are available. The equation for average RMS errors of estimated quantities can be written as following:

$$Acc3(m = c) = \frac{1}{c}\sum_{i=1}^{c}\sqrt{\frac{1}{T}\sum_{t=1}^{T}\left(q_{estim,i}(t) - q_{event,i}(t)\right)^2} \tag{6}$$

Where $q_{event,i}$ is the real value simulated in RTDS and $q_{estim,i}$ is the estimated value.

Fourth metric tells the average RMS error of estimated quantities with reduced measurement setup when only one or two measurement points are available. Idea of this metric is the same than in previous metric but in this case measurement information is available only from RTU and one or two smart meters. The equation for average RMS errors of estimated quantities with reduced measurements can be written as following:

$$Acc4(m = 1\ or\ 2) = \frac{1}{c}\sum_{i=1}^{c}\sqrt{\frac{1}{T}\sum_{t=1}^{T}\left(q_{estim,i}(t) - q_{event,i}(t)\right)^2} \quad (7)$$

Where $q_{event,i}$ is the real value simulated in RTDS and $q_{estim,i}$ is the estimated value.

Fifth metric tells the average RMS error of estimated quantities when one or two customers have erroneous measurements (measurement accuracy is bad, sensor or meter is broken, etc.). This metric will show how the state estimation performs when some of the measurements are erroneous. The equation for average RMS errors of estimated quantities with complete measurement setup can be written as following:

$$Acc5(e = 1\ or\ 2) = \frac{1}{c}\sum_{i=1}^{c}\sqrt{\frac{1}{T}\sum_{t=1}^{T}\left(q_{estim,i}(t) - q_{event,i}(t)\right)^2} \quad (8)$$

Where $q_{event,i}$ is the real value simulated in RTDS and $q_{estim,i}$ is the estimated value.

Sixth metric tells the ratio of average RMS errors of estimated quantities when weighted and unweighted state estimations are compared. Idea of this metric is to see if removing of old measurement information improves the accuracy of state estimation. Measurements used for state estimation are weighted less relevant when they get older. If measurements are not received from some of the meters for a while, then the values of these measurements are representing different network state than the new values from other meters. When the time difference increases, it is likely that old values are disturbing the LV network state estimation. The equation for comparing state estimations can be written as following:

$$Acc6(m = c) = \frac{\frac{1}{c}\sum_{i=1}^{c} RMS_{unweighted}}{\frac{1}{c}\sum_{i=1}^{c} RMS_{weighted}} \quad (9)$$

Where $q_{event,i}$ is the real value simulated in RTDS and $q_{estim,i}$ is the estimated value.

Seventh metric tells the average RMS error of estimated quantities with different smart meter reading frequency. Idea of this metric is to find suitable measurement reading frequency for state estimation purpose. The equation for average RMS errors estimated quantities with different smart meter reading frequency can be written as following:

$$Acc7(m = c) = \frac{1}{c}\sum_{i=1}^{c}\sqrt{\frac{1}{T}\sum_{t=1}^{T}\left(q_{estim,i}(t) - q_{event,i}(t)\right)^2} \qquad (10)$$

Where $q_{event,i}$ is the real value simulated in RTDS and $q_{estim,i}$ is the estimated value.

Eighth metric tells the average RMS error of estimated quantities with different averaging of measurement quantities. Idea of this metric is to find suitable averaging window for state estimation purpose. The equation for Average RMS error of estimated quantities with different averaging of measurement quantities can be written as following:

$$Acc8(m = c) = \frac{1}{c}\sum_{i=1}^{c}\sqrt{\frac{1}{T}\sum_{t=1}^{T}\left(q_{estim,i}(t) - q_{event,i}(t)\right)^2} \qquad (11)$$

Where $q_{event,i}$ is the real value simulated in RTDS and $q_{estim,i}$ is the estimated value.

6.3 Low voltage network fault management

At the LV network level, faults have traditionally not been monitored at all and fault notifications have mostly come from customers. In this use case fault detection is extended to cover the LV network and real-time information about faults and dangerous circumstances can be provided to I-Dev PC and finally to SCADA automatically. Fault management is used to reduce outage time in LV network and to improve safety of the LV network. [25]

When a smart meter detects fault in LV network it sends alarm to I-Dev PC, which may locate the faulted area of the LV network. I-Dev PC uses the location of alarming smart meters and network topology to locate the faulted area in the LV network. If necessary, I-Dev PC can send verification query to smart meters to be sure about the connection point status. If only one smart meter is not reachable then problem is probably connected to the single user. If there are many smart meters non-reachable on the same LV feeder, the problem is on that feeder. But if there are many smart meters non-reachable on different LV feeders on the same substation, the problem is in substation or on the MV network. The LV network modelled in this work has only one feeder and therefore fault detection is examined in one feeder only. [25]

Single and two-phase LV network faults are easier to locate than three-phase faults. In three-phase faults it is important to ensure if the fault is on LV or MV side of the network. If three-phase fault is on LV side, an alarm is send to SCADA. But if it is on MV side, no alarm is sent to SCADA because sending alarms from multiple of I-Dev PCs might congest the communication network. [25]

Smart meters also detect dangerous circumstances in the LV network such as broken neutral conductor and over and under voltage based on measurements in customer connection point. Power quality meters have certain threshold levels for dangerous circumstances and if the levels are exceeded it knows what kind of event it is. In dangerous circumstances power quality meter will isolate customer from the LV network in order to maintain safety of the LV network. It will also send alarm to I-Dev PC and finally to SCADA. Main things to study in fault management: [25]

- How fast outage alarm and fault indication may be send to I-Dev.
- How accurately fault management algorithm performs in varying LV network conditions and disturbances.
- How well the safety risks of broken neutral conductor may be prevented by fault analysis algorithm in power quality meter.
- How accurate the fault management algorithm performs in communication system problems.
- Quality monitoring and fault indication (e.g. broken neutral conductor does not cause unnecessary quality alarms).
- How quality monitoring behaves in different fault situations.

6.3.1 Metrics for LV network fault management

The LV network fault management use case is tested by simulating different kinds of fault situations (earth fault, two and three-phase short circuits and broken neutral conductor) in different parts of the LV network. Main studies are to check if the faults are correctly indicated and located and then that correct alarms are received by SCADA. The LV network fault management is divided into response time and accuracy and the metrics used in these tests are listed below. [27]

1*) Response time*

First metric in fault management tells the average time delay to detect an outage area. The equation for average time delay to get outage alarm can be written as following:

$$RT4 = \frac{1}{T}\sum_{t=1}^{T} \left(t_{detect,i}(t) - t_{outage,i}(t)\right) \tag{12}$$

Where T is the number of outages within study period, $t_{detect,i}$ is the time when the outage alarm is stored to database and $t_{outage,i}$ is the timestamp of outage alarm created by measurement unit.

Second metric tells the average time delay to disconnect customer in neutral conductor fault. Time delay is calculated from the real occurrence time of broken neutral conductor to the time when the customer is disconnected from the network. The equation for average time delay to disconnect customer can be written as following:

$$RT5 = \frac{1}{T}\sum_{t=1}^{T} \frac{1}{c_{zero}}\sum_{i=1}^{c_{zero}} \left(t_{disconnect,i}(t) - t_{zero,i}(t)\right) \tag{13}$$

Where T is the number of events within study period, c_{zero} is the number of customers behind the broken neutral conductor, $t_{disconnect,I}$ is the number of customer disconnections and $t_{zero,I}$ is the real occurrence times of broken neutral conductor.

2) *Accuracy*

Third metric tells the ratio of correctly located faults to all faults. Idea of this metric is to test if fault location algorithm is working correctly. Different fault types and locations are simulated. The equation for fault location accuracy can be written as following:

$$Acc9 = \frac{n_{correct\ fault\ location}}{n_{faults}} \tag{14}$$

Where $n_{correct\ fault\ location}$ is the number of correctly located faults and n_{faults} is the number of all faults.

Fourth metric tells the ratio of correct customer isolations due to broken neutral conductor and all neutral conductor faults. Idea of this metric is to test if the logic of broken neutral conductor detection is sensitive enough to detect all broken neutral conductor faults. The equation for broken neutral conductor can be written as following:

$$Acc10 = \frac{n_{correct\ zero\ faults}}{n_{zero\ faults}} \tag{15}$$

Where $n_{correct\ zero\ faults}$ is the number of customer isolations due to broken neutral conductor and $n_{zero\ faults}$ is the number of all neutral conductor faults.

Fifth metric tells the ratio of correctly located faults to all faults when communication to smart meter is lost. Idea of this metric is to test how well the fault location algorithm performs when measurement information is not available from every measurement point. The equation for fault location accuracy in communication problems can be written as following:

$$Acc11 = \frac{n_{correct\ fault\ location}}{n_{faults}} \tag{16}$$

Where $n_{correct\ fault\ location}$ is the number of correctly located faults and n_{fault} is the number of all faults.

Sixth metric tells the ratio of missed fault indications and unwanted power quality alarms to all faults. The equation for coordination between power quality alarms and fault detection can be written as following:

$$Acc12 = \frac{n_{missed\ faults} + n_{unwanted\ PQ\ alarms}}{n_{faults}} \tag{17}$$

Where $n_{missed\ faults}$ is the number of missed fault indications, $n_{unwanted\ PQ\ alarms}$ is the number of unwanted power quality alarms and n_{fault} is the number of all faults.

7 RESULTS

7.1 Low voltage network monitoring

Average RMS error of monitored quantities was tested with the measurements from the RSCAD simulator. Meter reading frequency and averaging of measurements was varied and this test was done by using predefine load profiles. In tables 7.1 and 7.2 are represented the average RMS error for monitored voltage and current values during one-day period. Average RMS error values are also shown as a chart in figures 7.1 and 7.2.

Table 7.1. *Average RMS error of monitored voltage values.*

AVG/FREQ	1min freq	5min freq	10min freq	20min freq	30min freq	60min freq
1min avg	0.157 (V)	x	x	x	x	x
5min avg	0.265 (V)	0.376 (V)	x	x	x	x
10min avg	0.376 (V)	0.470 (V)	0.578 (V)	x	x	x
20min avg	0.526 (V)	0.593 (V)	0.666 (V)	0.796 (V)	x	x
30min avg	0.619 (V)	0.669 (V)	0.727 (V)	0.817 (V)	0.915 (V)	x
60min avg	0.770 (V)	0.801 (V)	0.838 (V)	0.903 (V)	0.969 (V)	1.116 (V)

Table 7.2. *Average RMS error of monitored current values.*

AVG/FREQ	1min freq	5min freq	10min freq	20min freq	30min freq	60min freq
1min avg	0.311 (A)	x	x	x	x	x
5min avg	0.874 (A)	1.448 (A)	x	x	x	x
10min avg	1.472 (A)	1.935 (A)	2.451 (A)	x	x	x
20min avg	2.182 (A)	2.461 (A)	2.753 (A)	3.274 (A)	x	x
30min avg	2.480 (A)	2.675 (A)	2.890 (A)	3.208 (A)	3.386 (A)	x
60min avg	2.949 (A)	3.068 (A)	3.202 (A)	3.431 (A)	3.569 (A)	4.002 (A)

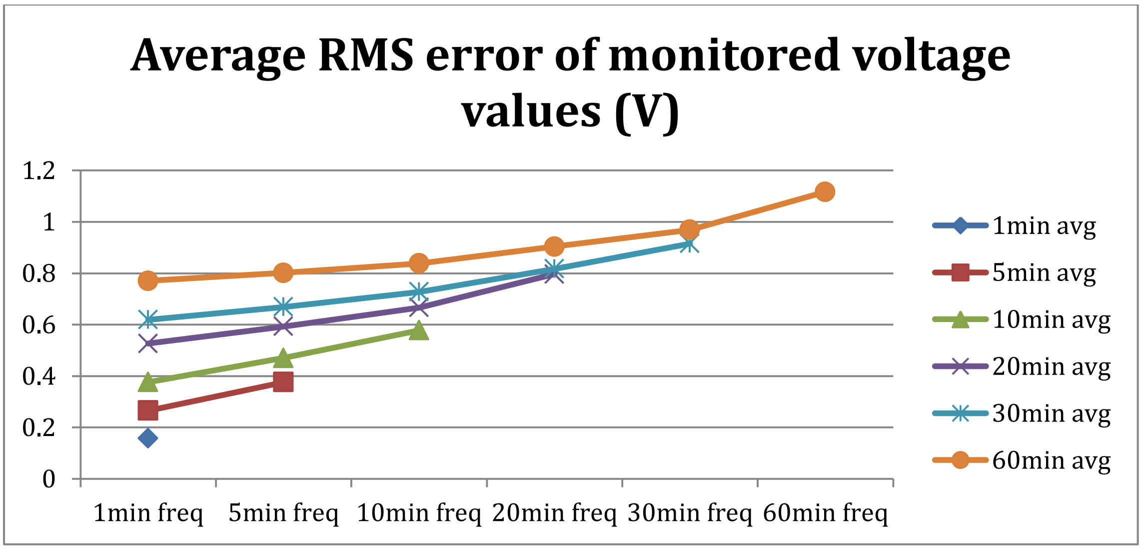


Figure 7.1. *Average RMS error of monitored voltage values.*

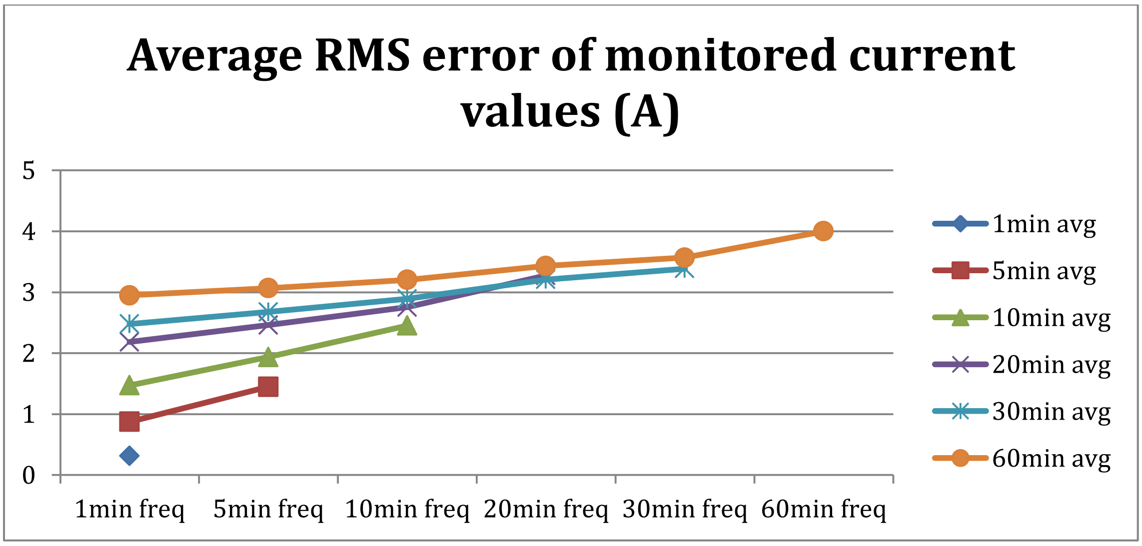


Figure 7.2. *Average RMS error of monitored current values.*

These results show that monitoring of voltage levels is accurate in spite of which reading frequency or averaging of measurements is used. Monitoring of current values will get quite inaccurate when the reading frequency and averaging of measurements increases and therefore it would be beneficial to use 10 minutes reading frequencies or smaller and 20 minutes averages or smaller.

The average time delay to get the information from the LV network was calculated from the time when the measurement information was requested from the I-Dev to the time it was received to the I-Dev database. At this point only RTU and Indra's smart meter time delays were possible to measure because of the interface problems between ThereGate and the I-Dev database. The average time delay to get measurements from RTU unit was 1.836 seconds. The delay is calculated from the time when the request to get the measurements from RTU is send to the time when the measurements are received to the database. The average time delay to get measurements from Indra's smart meter depends on the number of the modules installed in it. In TUT laboratory Indra's smart meter included three modules. The time delay to get the measurements from Indra's smart meter was approximately 40 seconds per module and in this case it was 2 minutes and 20 seconds. The delay was calculated between the timestamp from Indra's smart meter to the time when the measurements are received to the database.

7.2 Low voltage network congestion management

The state estimation algorithm was also tested with the measurements from the RSCAD simulator because of the interface problems between ThereGate and the I-Dev database. Therefore it was not possible at this point to calculate the average time delay to detect and remove the LV network congestion. Average RMS error of estimated quantities with complete measurement setup was tested with comparing customers' real voltage and current values from each phase to estimated values. Real voltage and current values were calculated by RSCAD and estimated values were calculated by state estimation algorithm. In first case input values for load estimation algorithm were voltage measurements from RTU unit and active and reactive power measurements from customers and RTU unit. In second case input measurements were voltage and current values from RTU unit and active and reactive power measurements from customers. In tables 7.3 and 7.4 are presented the average RMS error for each customer and total average RMS error for all customers in complete measurement setup during one-day period. Table 7.3 represents the results from the first case and table 7.4 represents results from the second case. Results are also shown as chart in figures 7.3 and 7.4.

Table 7.3. *Average RMS error of estimated quantities with voltage and current measurements from RTU.*

	Voltage (V)	**Current (A)**
Customer 3	0.002016584	0.03557409
Customer 5	0.00701885	0.035772288
Customer 7	0.012557692	0.03612349
Customer 9	0.021454509	0.033781723
Customer 10	0.015417371	0.036037848
Customer 12	0.012427034	0.036268824
Customer 13	0.021530243	0.02906953
Total	0.013203183	0.034661113

Table 7.4. *Average RMS error of estimated quantities with voltage and power measurements from RTU.*

	Voltage (V)	**Current (A)**
Customer 3	0.00456517	0.04340276
Customer 5	0.011125299	0.043724863
Customer 7	0.017063457	0.04477813
Customer 9	0.033068213	0.044828236
Customer 10	0.020260548	0.045748184
Customer 12	0.017504891	0.044853201
Customer 13	0.023321337	0.042170374
Total	0.018129845	0.044215107

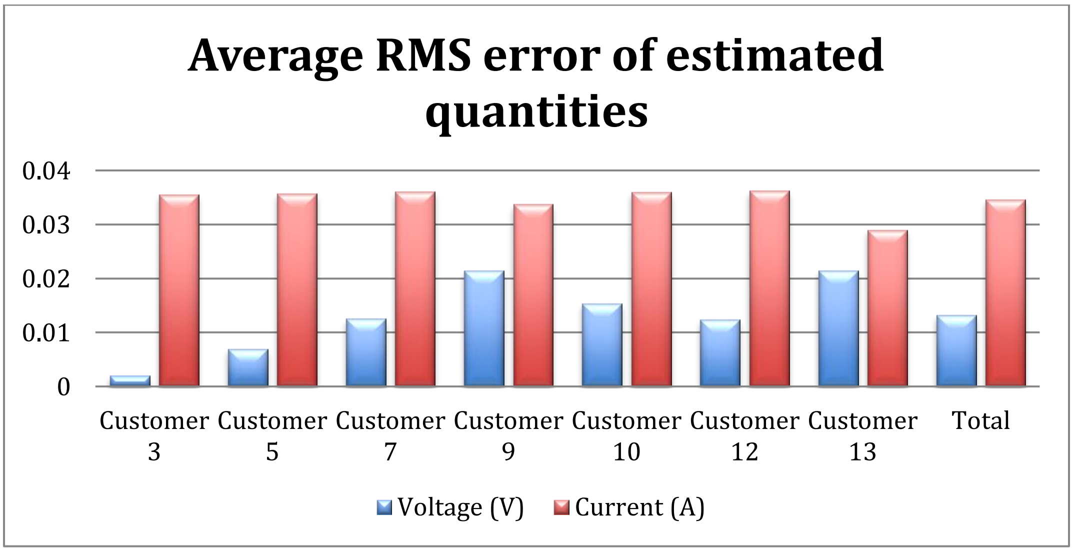


Figure 7.3. *Average RMS error of estimated quantities with voltage and current measurements from RTU.*

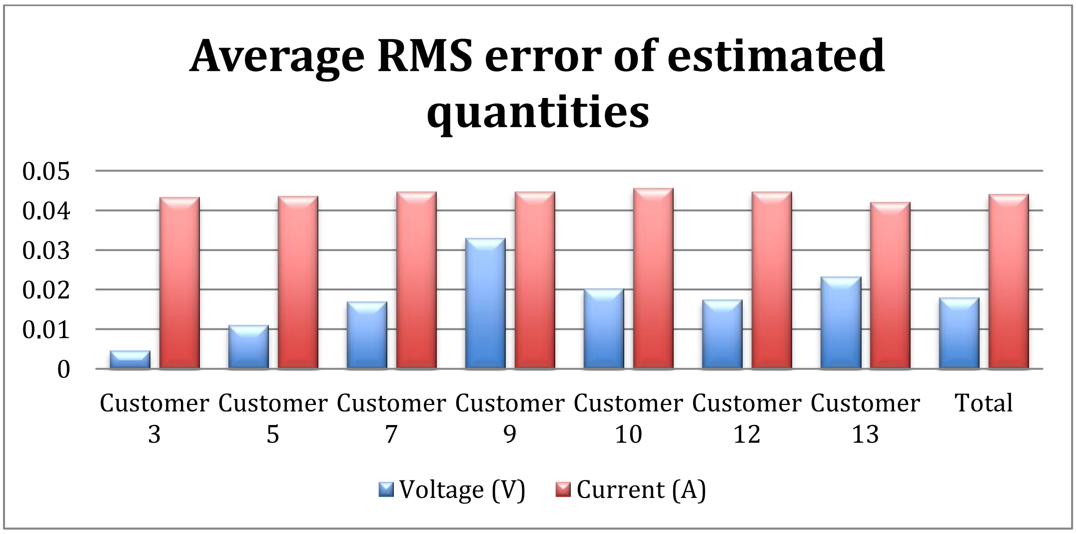


Figure 7.4. *Average RMS error of estimated quantities with voltage and power measurements from RTU.*

These results show that the estimated values are were very near to the real values when information from substation and every customer were available. Average RMS error for current estimation is almost the same for every customer but voltage estimation has small deviations. Customers three and five have the smallest average RMS errors in voltage estimation because they are located at the beginning of the feeder. The remaining customers have almost the same average RMS error in voltage estimation except customer 9, which has the highest error in voltage estimation. That is because it has some negative active power values and when the active power value is negative the estimation algorithm accuracy decreases a little. However, it still gives very accurate estimations. The results also show that estimated voltage values are more accurate than estimated current values. That is because voltage values do not vary as much as current values. These results also show that using voltage and current measurements from RTU will give better estimates. Therefore, voltage and current measurements from RTU unit were used in the remaining tests of load congestion management.

Average RMS error of estimated quantities with reduced measurement setup was tested with the same way as the complete measurement setup except that in this case customers' measurement points were reduced. First case was to test when only one measurement point was available and the second case was to test when two measurement points were available. In these cases average RMS error of estimated quantities is the sum of all the customers' RMS errors divided by the number of the customers. The figure 7.5 represents the results of estimated quantities when measurements were reduced.

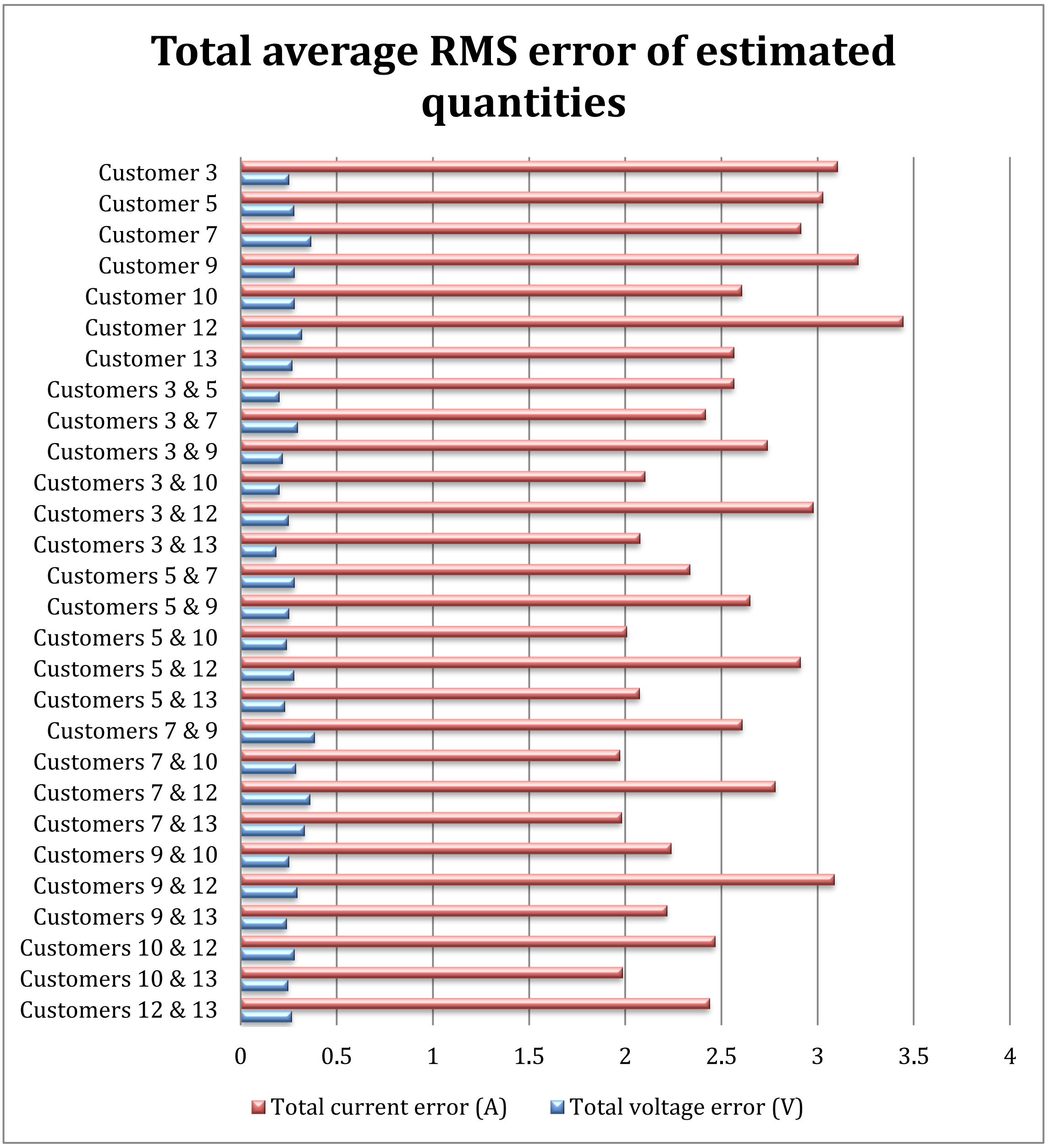


Figure 7.5. *Average RMS error of estimated quantities with reduced measurements.*

When the measurement points were reduced the estimation algorithm results started to become inaccurate. Voltage estimation remained still quite accurate but current estimation started to become inaccurate. The load model and the location of the customer had an effect on the estimation results. Results show that when only one measurement point is available the voltage estimation is most accurate when the measurement point is at the beginning of the feeder. Current estimation is most accurate when the measurement point is at the customer who has high load and is located at the end of the feeder. In two measurements case, the results show that the voltage estimation is most accurate when the measurement points are from the beginning of the feeder or from the beginning of the feeder and from the customer located at the end of feeder with high load. Current estimation is most accurate when the measurement points are from the customers that have high load and are located at the end of feeder. In this case from the customers seven, ten and thirteen. Table 7.5 represents the measurement points that give the three most accurate estimation values for voltage and current values.

Table 7.5. *The most accurate estimation values.*

Measurement points	Total voltage error (V)	Total current error (A)
Customers 3 & 13	**0.18166771**	2.07447424
Customers 3 & 10	**0.19797343**	2.10017319
Customers 3 & 5	**0.197807**	2.5633476
Customers 7 & 10	0.28430517	**1.97001995**
Customers 7 & 13	0.32945828	**1.9773209**
Customers 10 & 13	0.24490747	**1.98207747**

Results from the table above shows that measurement points should be installed to the beginning of the feeder and to the customer who has high load and is located at the end of feeder. In this case to the customers three and thirteen.

Average RMS error with varying error degree was tested by giving one or two erroneous measurement values to state estimation algorithm. Voltage, current and power measurements from RTU unit and power measurements from smart meters were changed to erroneous measurement values. The state estimation algorithm removes erroneous voltage measurements from RTU when voltage values are at least two times higher or ten times smaller than nominal value, which in these simulations was over 460 V or under 23 V). It also removes negative current values from RTU measurements. When voltage or current values from RTU were removed the state estimation output value was NaN. In these cases the average RMS error was not possible to calculate. When voltage measurements from RTU were between mentioned thresholds and current measurements from RTU were positive but power measurements from some of the customers were erroneous the state estimation algorithm did not remove erroneous measurements. The state estimation algorithm used those erroneous measurement values in state estimation and it did not give reasonable output values for customers and therefore the state estimation algorithm did not work as it was supposed to work in this case. However, removing erroneous measurements from state estimation has not been paid particular attention when the algorithm was developed.

Comparison between weighted and unweighted state estimations was tested with giving old measurement information from one customer to the state estimation algorithm. Other customers' measurements were normal. The duration of the old measurement information was tested with five different time intervals. Estimated voltage and current measurements were compared to real measurements and the results will show in which time the old measurements should be removed from the state estimation calculations. In this case the smart meter reading frequency was one minute and the averaging of measurements was ten minutes. Measurements from every customer were available. The results of this case are from customer 7 and they are presented in table 7.6 and in figures 7.7 and 7.8. Figures of weighted vs. unweighted voltage and current measurements during one-day period can be found from appendix three. Those figures are from customer 7 measurements.

Table 7.6. *Average RMS error of estimated quantities (weighted vs. unweighted).*

	Voltage (V) weighted	**Voltage (V) unweighted**	**Current (A) weighted**	**Current (A) unweighted**
30min old	0.07769062	0.09490639	0.27534423	0.70535851
60min old	0.09504595	0.10023169	0.29887139	0.70120102
90min old	0.4420915	0.50692267	0.40195439	1.29262538
120min old	0.39689126	0.45558922	0.55327282	1.51671418

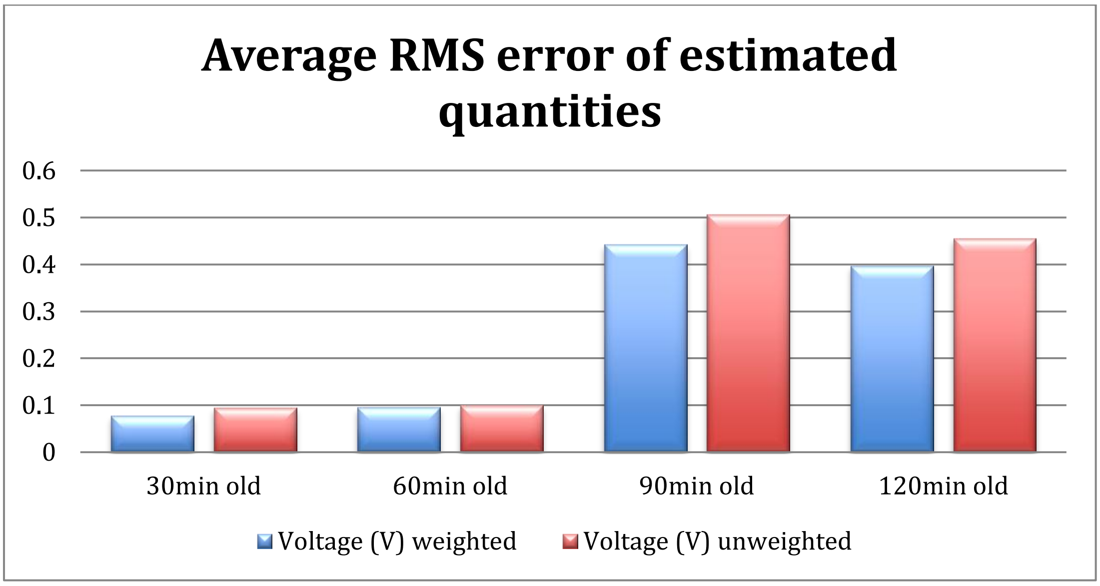


Figure 7.7. *Average RMS error of estimated voltage values (weighted vs. unweighted).*

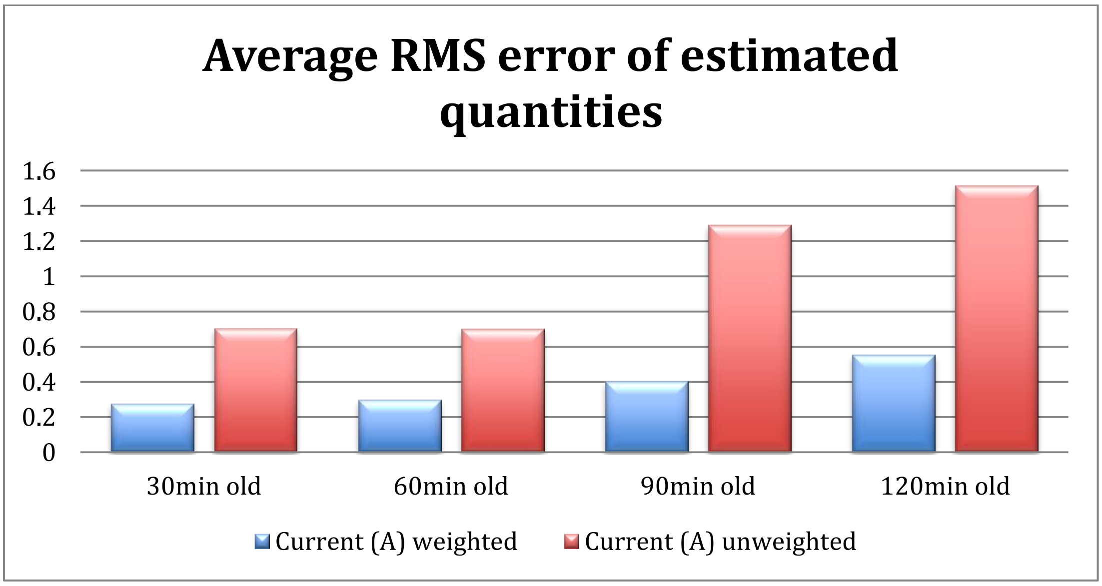


Figure 7.8. *Average RMS error of estimated current values (weighted vs. unweighted).*

Customer's load profile has high effect on the results of this case. If customer has high variations in power, like in these simulations customers' load profiles, forgetting old measurements should be done quite quickly. In this case, the results show that using weighted measurements will significantly improve the current estimation but has only a small effect on voltage estimations. It also shows that old measurements should be removed at least after one hour because after that the current estimation becomes inaccurate when old measurement information is used. The correct time to remove the old measurements cannot be determined precisely because customers have different kind of load profiles but one-hour time limit can be considered as a good estimate.

Average RMS error of estimated quantities with different smart meter reading frequency was tested with three different reading frequencies. In this case, measurements from transformer and every customer were available. Ten-minute average values from smart meter were used and the reading frequency was varied. The results of this case are represented in table 7.7 and in figures 7.9. Figures of real voltage and current values compared to the estimated values with different smart meter reading frequency can be found from appendix four. Those figures are from one phase of customer 10.

Table 7.7. *Average RMS error of estimated quantities during one-day period.*

	Voltage (V)	Current (A)
1 min freq	0.341899844	1.317271646
5 min freq	0.423660833	1.681708563
10 min freq	0.518917253	2.097120603

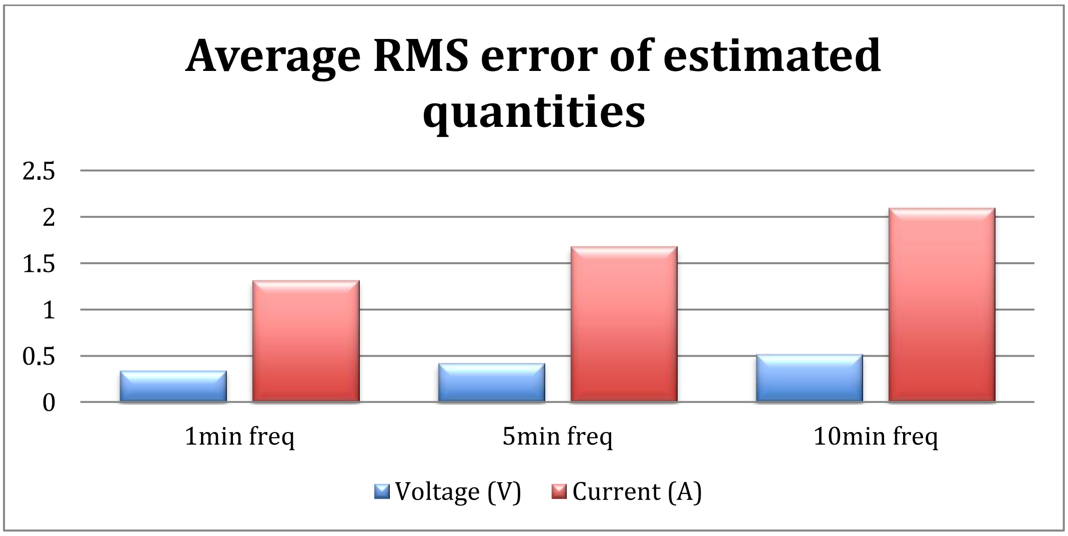


Figure 7.9. *Average RMS error of estimated quantities with different smart meter reading frequency.*

These results show that the estimation of voltage values is quite accurate, but the estimation of current values starts to get more inaccurate when the smart meter reading frequency increases. The reason for current estimation inaccuracy in ten-minute reading frequency is that it will take longer time to detect changes in customer connection point. In addition, some of the load profiles used in these simulations have high variation in power, which will also affect to the accuracy. However, figures in appendix pages show that it does not matter which reading frequency is used because state estimation will detect the same highest and lowest voltage and current values in the customer connection point. Therefore, changing the smart meter reading frequency between one to ten minutes does not have major impact on the state estimation results. It will only affect to the amount of data stored to database and to the time to detect the highest and lowest values. The longer the reading frequency is the longer the time delay will be. Storing data to the database should not be a problem in today's databases.

Average of estimated quantities with different averaging measurements was tested with six different average measurements and the smart meter reading frequency was one minute. In this case, measurements from transformer and every customer were available. The results of this case are represented in table 7.8 and in figure 7.10. Figures of real voltage and current values compared to the estimated values with different averaging of measurements can be found from appendix five. Those figures are from one phase of customer 10.

Table 7.8. *Average RMS error of estimated quantities during one-day period.*

	Voltage (V)	**Current (A)**
1 min avg	0.15316933	0.46393976
5 min avg	0.248314025	0.886345166
10 min avg	0.342313021	1.318089788
20 min avg	0.476584466	1.911617512
30 min avg	0.566253908	2.2718313
60 min avg	0.699648727	2.755854269

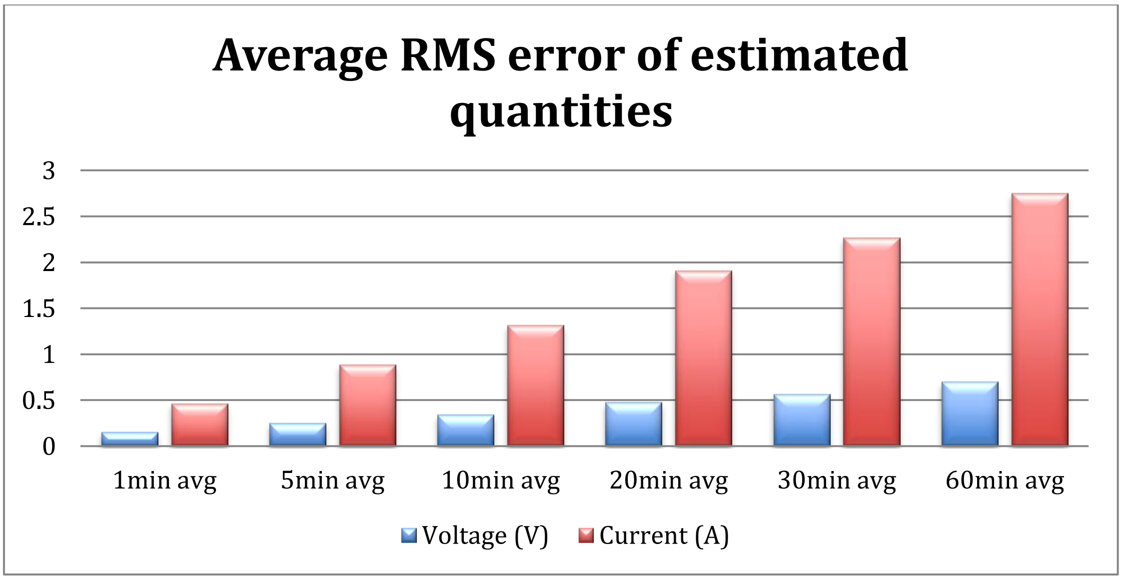


Figure 7.10. *Average RMS error of estimated quantities with different averaging of measurement quantities.*

In this case also, the estimation of voltage values is accurate and the estimation of current values starts to get more inaccurate when the averaging of measurements increases. Figures in appendix pages show that 10-minute and smaller average measurements will provide accurate voltage estimation values. 20-minute and bigger average measurements will also provide sufficiently accurate voltage estimation values. Current estimations are sufficiently accurate when using ten-minute or smaller averaging of measurements. Using 20-minute or bigger average measurements will not detect the biggest current values in the customer connection point. Therefore, ten-minute average measurements will give the optimal estimated voltage and current values.

7.3 Low voltage network fault management

The fault location algorithm was also tested with the measurements from the RSCAD simulator because of the interface problems between ThereGate and database. Therefore, it was not possible at this point to calculate the real average time delay to detect outage in the LV network. Also coordination between power quality alarms and fault detection was unable to measure.

Average time delay to disconnect customer in dangerous events was tested by creating 20 neutral conductors faults to the LV network. The power quality meter has threshold levels for neutral conductor fault that are used to detect the neutral conductor fault. When those threshold values are exceeded the power quality meter sends signal to RSCAD to disconnect the customer. The time delay to disconnect the customer was calculated from the time when neutral conductor fault was created in the RSCAD simulator to the time when the customer was disconnected in the RSCAD. Fastest disconnection time was 13 seconds and slowest 45 seconds. The average time delay for customer isolation is 25.5 seconds. Time delay to disconnect the customer was fast and this should minimize life-threatening situation in customer's connection point. Disconnection time could be set even faster but it might cause unwanted disconnection from other disturbances like voltage asymmetry.

The accuracy of the LV network fault location algorithm was tested by creating different kinds of faults to every customer in the LV network. Phase faults, neutral conductor faults and wrong phase order faults were created. Fault location algorithm should detect these faults and identify which kind of fault it is. In this case measurement information was available from every customer. Total number of different kinds of faults was 63 and the fault location algorithm did detect and identify all of these faults. The result show that the fault location algorithm works as it should be when information from every customer is available.

The accuracy of correct customer isolations in neutral conductor fault was tested with 40 different neutral conductor faults in the LV network. Almost every fault was detected and isolated from the LV network. In two events the PQ meter did not detect the neutral conductor fault. The neutral conductor faults did not last over one minute because the amplifier used in these tests will not last very long for very high current values. Therefore, it is possible that the PQ meter could have been able to detect those two faults if the time period would be longer. Ratio for correct customer isolations is 0.95. The results show that correct customer isolation works almost perfectly. However, the customer disconnection time is not the same every time and therefore it might affect the detection of neutral conductor fault and customer isolation. For example if the neutral conductor fault is between the nodes six and eight, as presented in the figure 7.11, and customers' power quality meters will not detect the fault at the same time. In that kind of situation the isolation of customer 9 will have effect on the voltage levels of the customer 10 and it might cause a problem where customer 10 is not isolated from the network although it has also neutral conductor fault. This kind of case was not possible to test in these simulations because only one power quality meter was used.

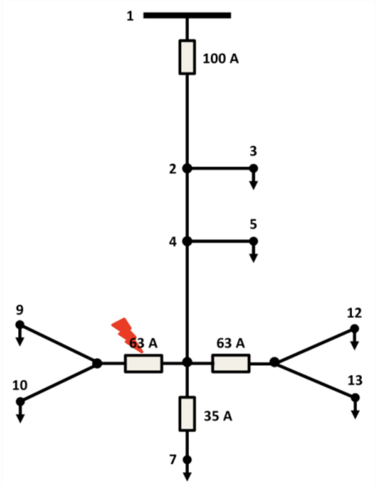
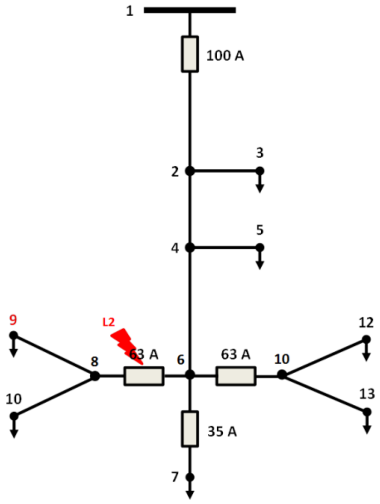


Figure 7.11. *Neutral conductor fault between nodes 6-8*

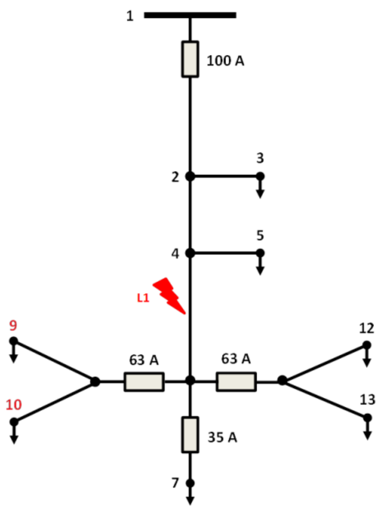
The accuracy of fault location algorithm in communication problems was tested with the same kind of faults as in the case where measurement information was available. In this case the available measurement points were varied. The fault location algorithm assumes three-phase fault to the customer when the measurement information is older than three minutes. In cases were only one measurement information was unavailable the fault location algorithm worked perfectly. For example, if the fault is in phase two between nodes six and eight and information from customer 9 is unavailable the fault location algorithm located correct fault point. The fault situation and the output of fault location algorithm are presented in the figure 7.12.



Phase voltage fault detected in phase L1
Between nodes
9 8
Phase voltage fault detected in phase L2
Between nodes
8 6
Phase voltage fault detected in phase L3
Between nodes
9 8

Figure 7.12. *L2 fault between nodes six and eight when customer 9 measurements are missing.*

The fault location algorithm detects the phase two fault between nodes six and eight and three-phase fault between nodes eight and nine. Another example is when the fault is in phase one and information from customers' nine and ten were unavailable the fault location algorithm did give output that is presented in figure 7.13. It also presents the fault situation in the LV network.



Phase voltage fault detected in phase L1
Between nodes
6 4
Phase voltage fault detected in phase L2
Between nodes
8 6
Phase voltage fault detected in phase L3
Between nodes
8 6

Figure 7.13. *L1 fault between nodes four and six when customers' 9 and 10 measurements are missing.*

In this case the fault location algorithm detects phase one fault between nodes four and six and three-phase faults between nodes six and eight. The latter information indicates that measurements from customers nine and ten are unavailable. Total number of simulated faults when one or two customer's measurements were unavailable in the LV network was 20 and in each of these tests the fault location algorithm did detect the correct fault type and location in the LV network.

8 CONCLUSIONS

8.1 Conclusions

The role of the LV network has become more important in the distribution network. Therefore, more intelligent solutions in the future LV network are required. AMR systems in the LV network have become more common, but AMR meters are currently used only for remote energy consumption reading and accurate billing of customers. However, AMR meters together with secondary substation monitoring unit could be utilized to increase the level of automation in the future LV network. Development of the LV network automation was studied in this thesis. The aim was to prove that the LV network monitoring, load congestion management and fault management could be used to improve the LV network management.

Monitoring of the LV network with smart meters and secondary substation monitoring unit provides important and accurate information of the LV network state. Monitoring cases gave good picture of what kind of average of the measurements and smart meter reading frequencies should be used in the LV network monitoring. Tests prove that the delay of the data transfer does not seem to have effect on the accuracy of the LV network monitoring. Therefore, the averaging of the measurements and the meter reading frequency has the highest impact on the accuracy of the LV network monitoring. Measurement information from the customers and secondary substation were utilized in the load congestion management and fault management.

Testing of the LV network state estimation was successful and the algorithm did work almost as it was supposed to work. Only problems in state estimation occurred when the measurements had erroneous values. In that case the state estimation did not give reasonable results and therefore the algorithm did not work as it was supposed to work. That is because removing erroneous measurements from state estimation has not been paid particular attention when the algorithm was developed. Nevertheless, utilizing state estimation in the LV network will clearly improve the LV network management. It provides accurate estimates for current, voltage and power flows in the LV network when measurement information from every customer connection point is not available. Current estimation was not as accurate as voltage estimation because current measurements vary more often and therefore, the estimation of voltage values was not as important as the estimation of current values. Estimation results also show that the location of the measurement points has high impact on the estimation accuracy. Voltage estimation is most accurate when the measurement points are from the beginning and from the customer located at the end of feeder with high load. Current estimation is most accurate when the measurement points are from the customers that have high load and are located at the end of feeder.

In the fault management tests there was only one case that could not be tested. It was the detection time of the fault because the fault information comes from ThereGate and the connection between ThereGate and database did not work at this point. In other test cases the fault management worked as it was supposed to work. The fault location algorithm did correctly locate faults in situation where the measurement information was available and in situations where the information was reduced. The power quality meter was able to isolate correct customer in a sufficiently short time when a neutral conductor fault occurred in the LV network. This feature will significantly reduce the dangerous events in the LV network.

Results of this thesis show that the LV network monitoring, load congestion management and fault management will improve the LV network management. These features provide accurate and almost real-time information of the LV network and it can be used to monitor the changes in the LV network more accurately. Therefore, also the automation level in the LV network can be increased, which will give significant benefits to the management of the LV network. Increasing automation in the LV network will provide better tools for the distribution companies for network state management, network planning, power quality management and fault management.

8.2 Further Study

In this thesis the load congestion management case was not fully tested. Controlling of customers' load and distributed generation should be tested in further studies. The operation time of the power flow and voltage management algorithm should be tested. How fast it will detect problem in the network and how fast it controls the loads or distributed generation in order to avoid unwanted situations in the LV network. Couple of the customers in the modelled LV network should be equipped with controllable loads and couple of the customers with distributed generation. Overvoltage, undervoltage and overloading situations should be created to the network and examine how well these unwanted situations could be managed with only couple of controllable loads and distributed generation in the LV network. This would give good estimate of how much controllable loads and distributed generation is needed to control unwanted loading situations in this kind of LV network.

Power quality management should also be tested in further studies. How well the power quality changes, such as flicker and harmonics, could be monitored from SCADA. This information could be used to reveal the weakest points of the LV network in the power quality point of view. In addition, how power quality changes will affect to fault management. For example, is it possible that in large voltage asymmetry situations the power quality meter thinks that there is a neutral conductor fault in the network and isolates the customer. This would be utilized to avoid unnecessary isolations from the network.

The fault management should also be tested when the fault is in the MV network. If the fault is in the MV network it is unnecessary to use the fault location algorithm and it would only send useless information to database. However, there is sometimes also fault in the LV network and some customers may still remain without supply even though the MV network fault has been repaired. In these kinds of cases it is important to examine how fast the fault location algorithm will detect that there is still outage in part of the LV network. This will decrease the interruption and repairing costs and bring savings to the distribution companies.

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APPENDIX 1 – LOAD MODELS USED IN LOW VOLTAGE NETWORK MANAGEMENT

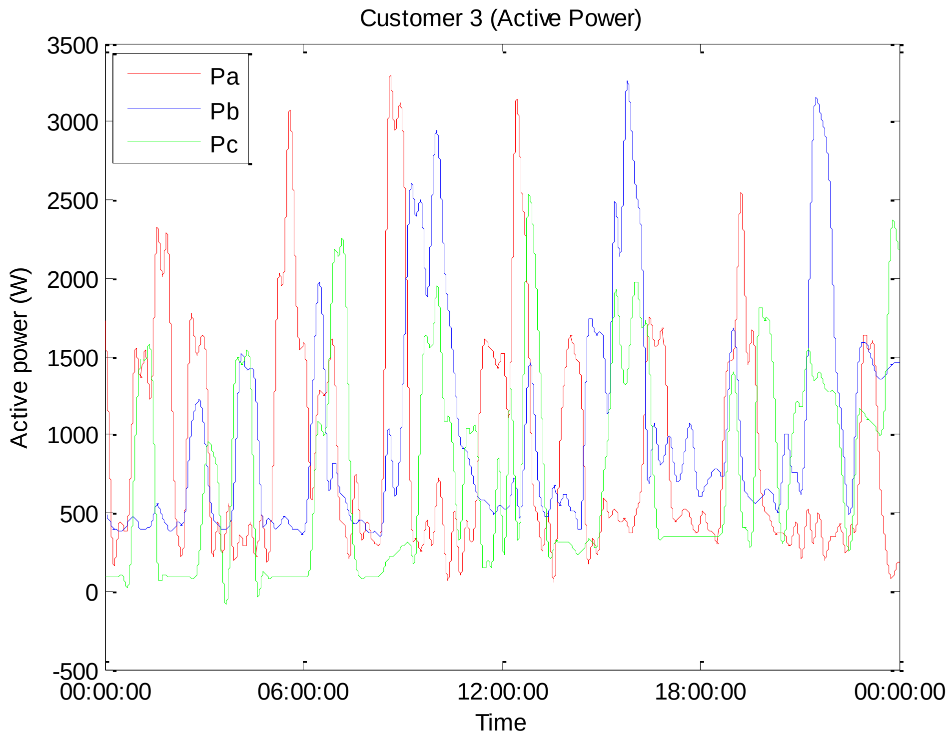

Figure 1 *Customer 3 active power during one-day period.*

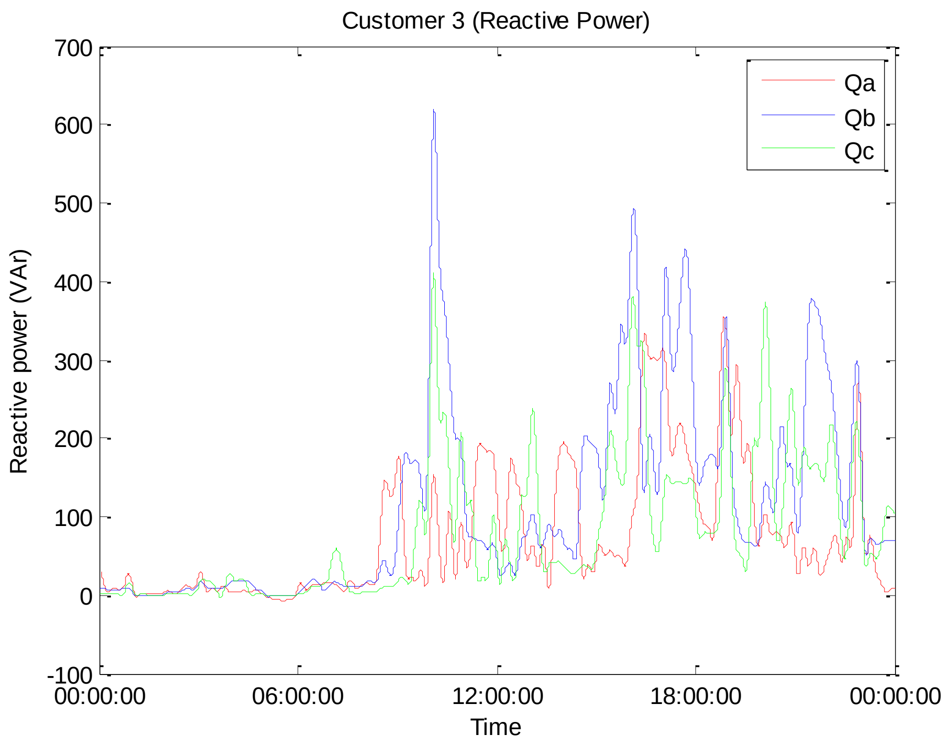

Figure 2 *Customer 3 reactive power during one-day period.*

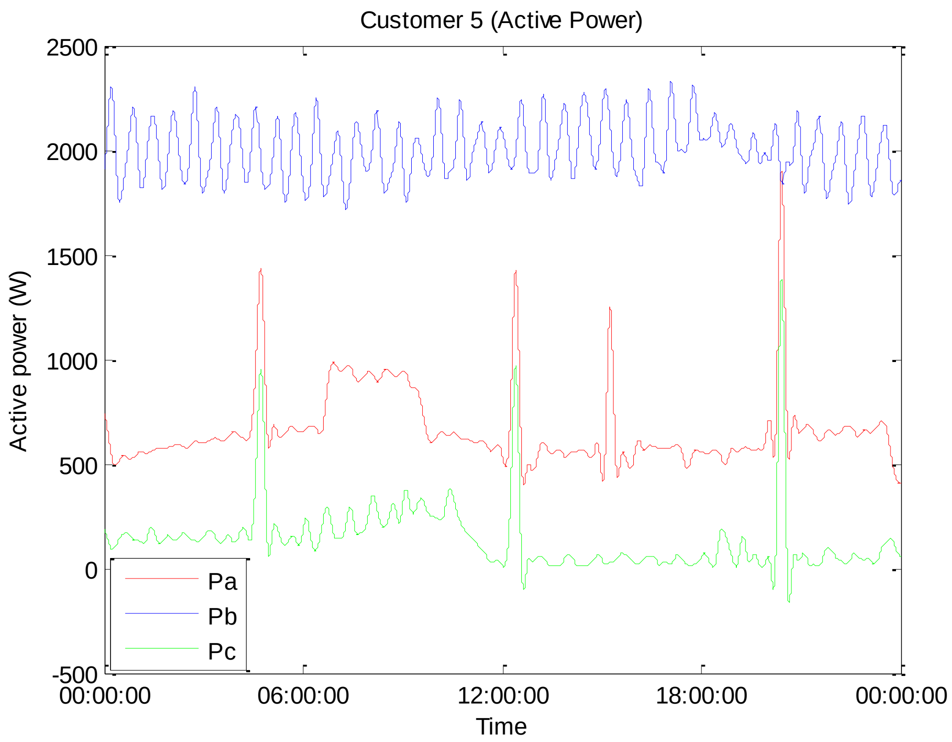

Figure 3 *Customer 5 active power during one-day period.*

Figure 4 *Customer 5 reactive power during one-day period.*

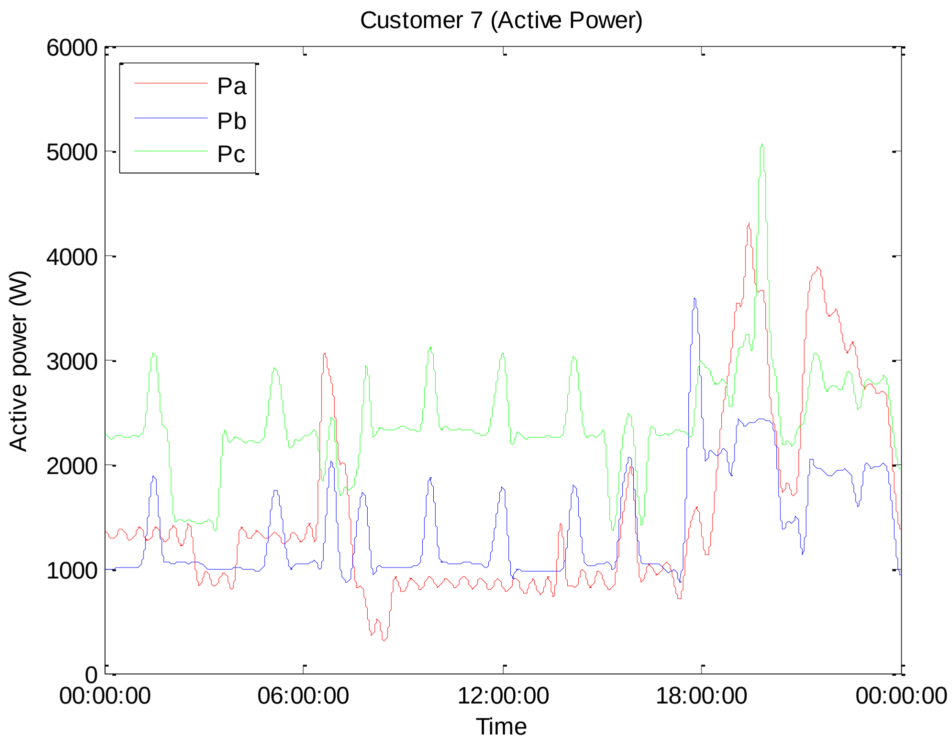

***Figure 5** Customer 7 active power during one-day period.*

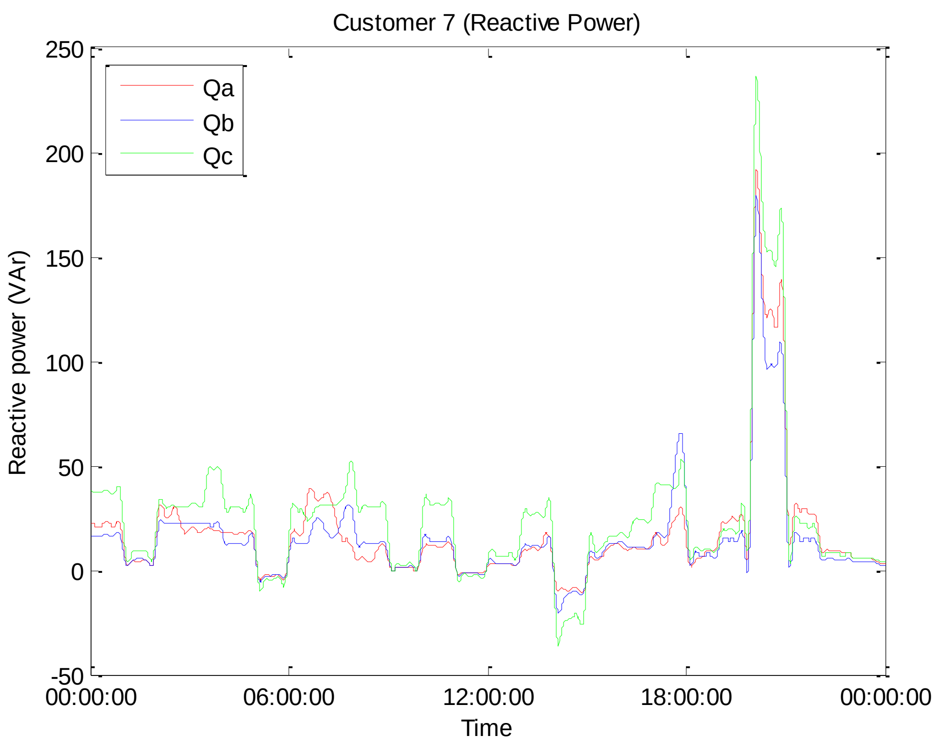

***Figure 6** Customer 7 reactive power during one-day period.*

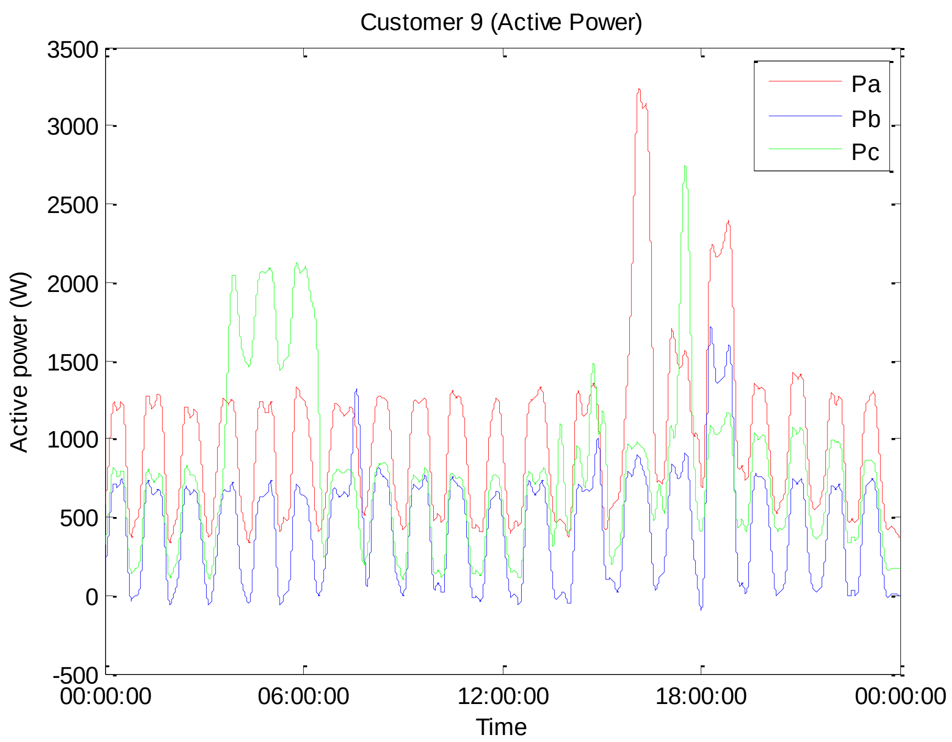

Figure 7 *Customer 9 active power during one-day period.*

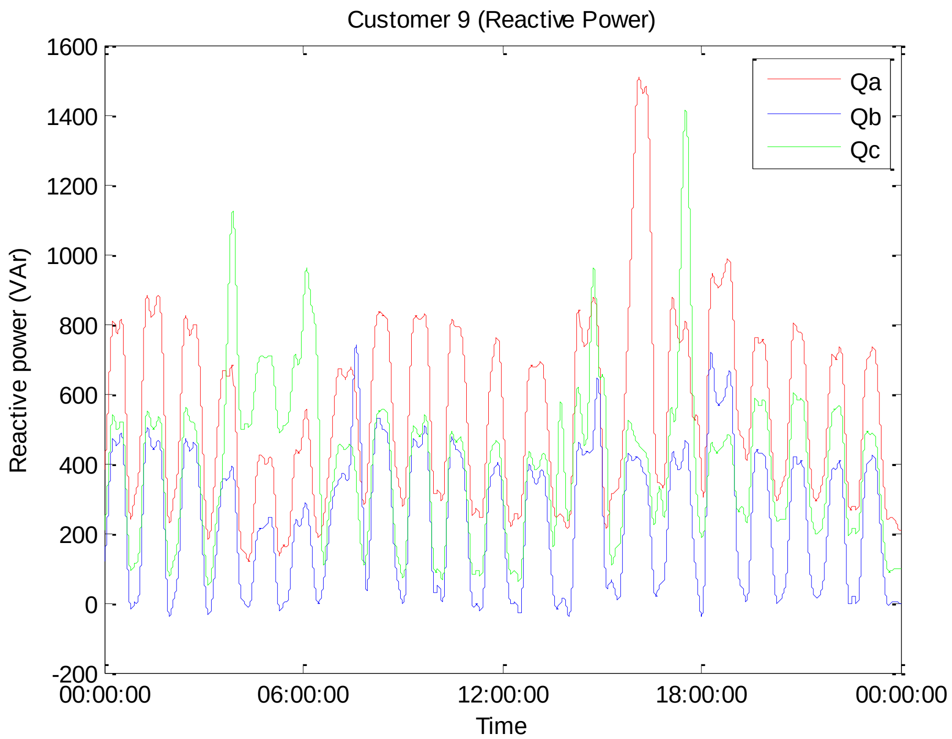

Figure 8 *Customer 9 reactive power during one-day period.*

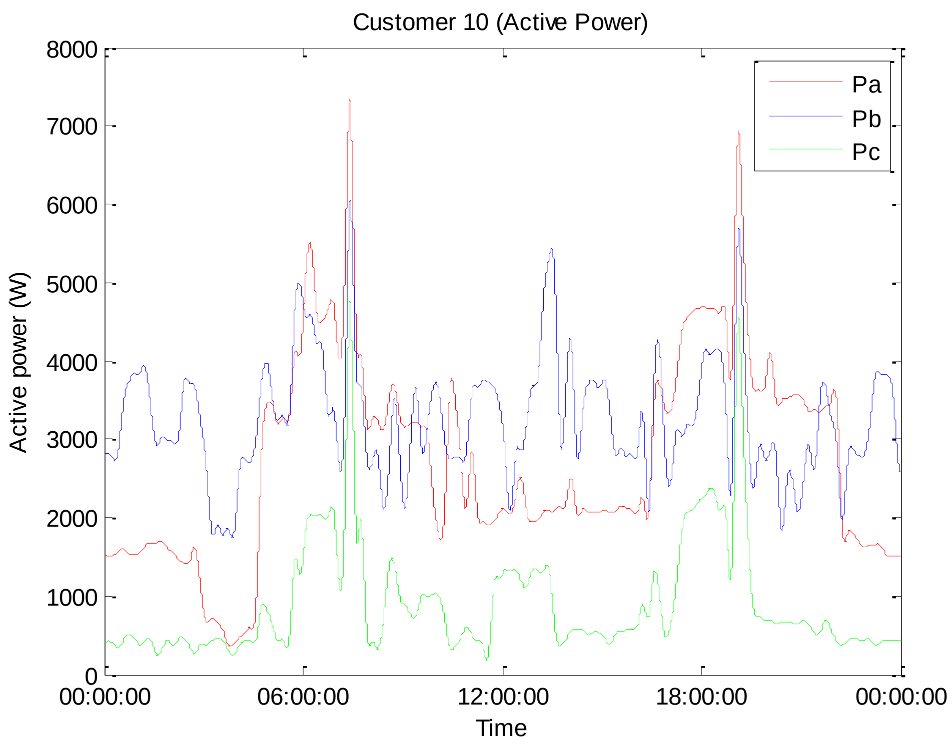

Figure 9 *Customer 10 active power during one-day period.*

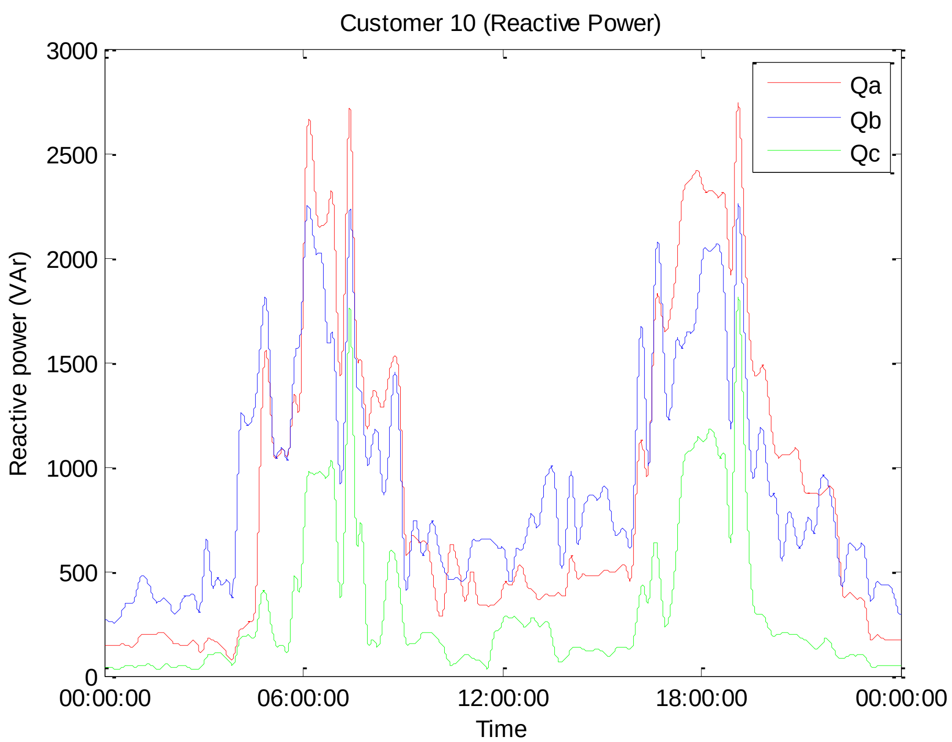

Figure 10 *Customer 10 reactive power during one-day period.*

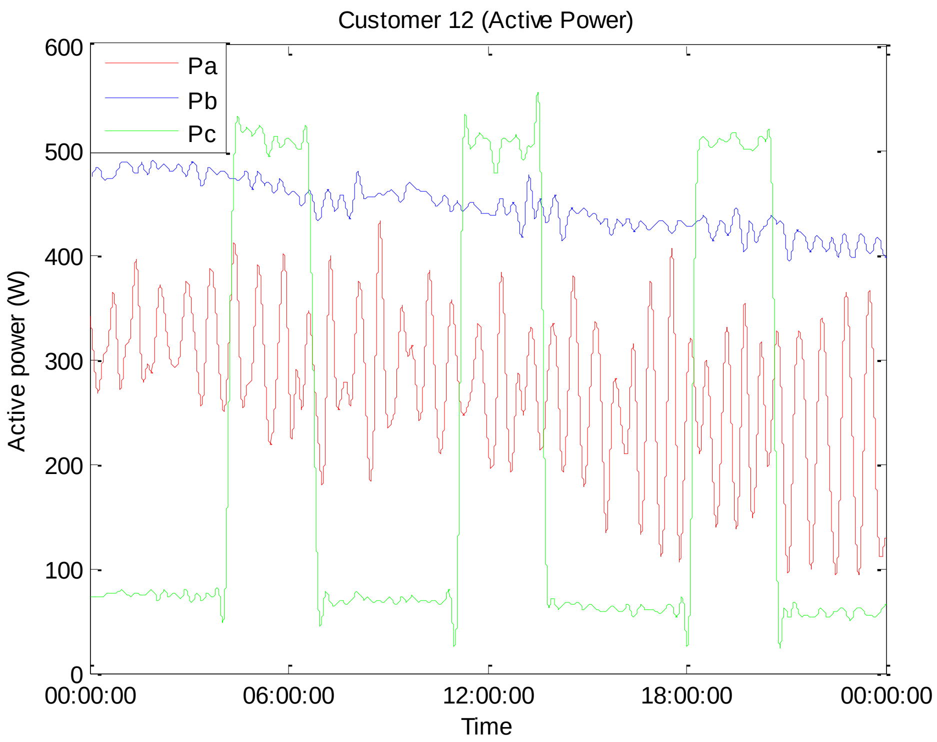

***Figure 11** Customer 12 active power during one-day period.*

***Figure 12** Customer 12 reactive power during one-day period.*

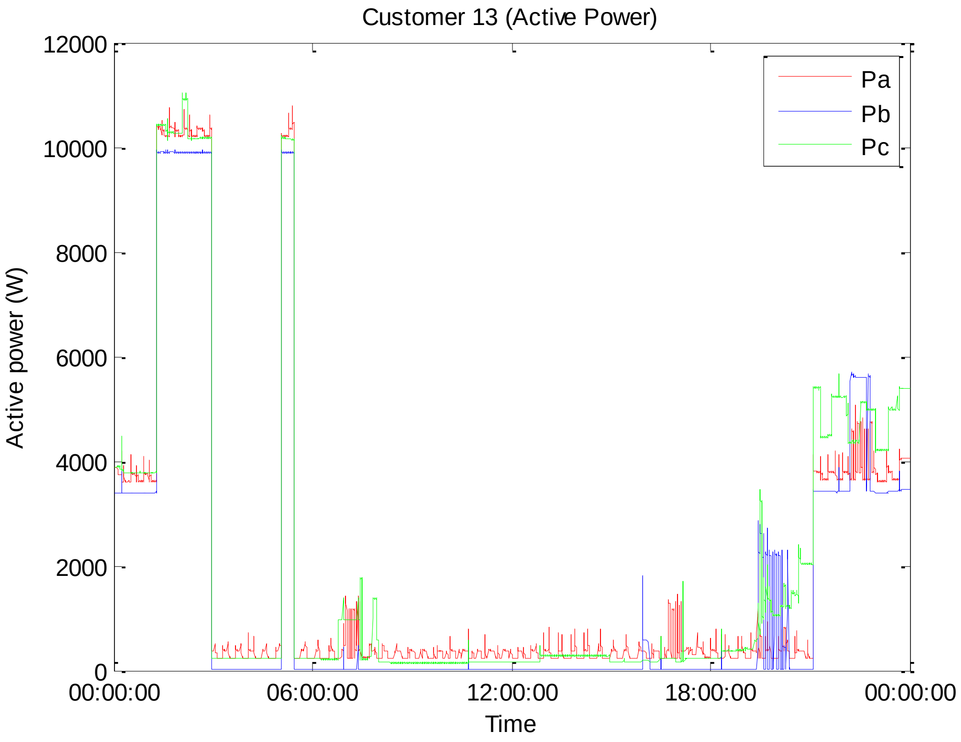

Figure 13 *Customer 13 active power during one-day period.*

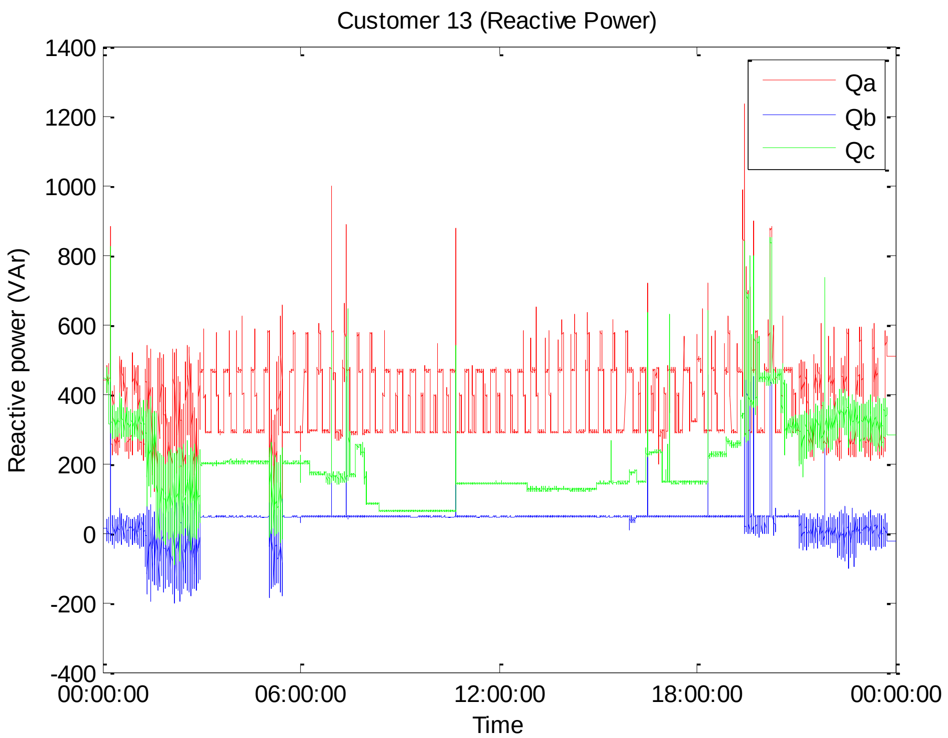

Figure 14 *Customer 13 reactive power during one-day period.*

APPENDIX 2 – DETAILED INFORMATION OF THE MODELLED LOW VOLTAGE NETWORK

CUSTOMER INFORMATION

Customer	Measurement interval	Customer Type	Fuse	Heating solution
3	10min	Detached house	3x25A	Partial electric storage heating, electric sauna stove
5	10min	Detached house	3x25A	Direct electric heating
7	10min	Detached house	3x25A	Direct electric heating
9	10min	Detached house	3x25A	Direct electric heating
10	10min	Farm	3x35A	Solid fuel (wood) heating, electric sauna stove
12	10min	Recreational dwelling	3x25A	Direct electric heating
13	10min	Detached house	3x63A	Electric storage heating, several heated outbuildings

CABLE INFORMATION

Line	Line type	Diameter(mm^2)	length(m)	R/phase(Ω)	X/phase(Ω)	Rated current (A)	Fuse (A)
1-2	Ground cable	4x120	51	0.012903	0.004182	255	100
2-3	Installation cable	4x10	8	0.0156	0.00088	45	
2-4	Overhead line	3x70+95	66	0.028578	0.006402	180	
4-5	Ground cable	4x25	32	0.0384	0.002624	100	
4-6	Ground cable	4x95	91	0.02912	0.007462	220	
6-7	Ground + installation cable	4x25 +3x70+95	37+9	0.06195	0.007462	45	35
6-8	Busbar	-					63
6-11	Busbar	-					63
8-9	Ground cable	4x25	111	0.1332	0.009102	100	
8-10	Ground cable	4x25	49	0.0588	0.004018	100	
11-12	Ground cable	4x25	70	0.084	0.00574	100	
11-13	Ground cable	4x25	64	0.0768	0.005248	100	

TRANSFORMER INFORMATION

$S_n = 315\ kVa$
$U_n = 20\ kV/400\ V$
$Z_0 = 1.2\ \%$
$U_k = 5\ \%$
$P_k = 4359\ W$
$P_0 = 570\ W$
$D\acute{Y}n11$

APPENDIX 3 – FIGURES OF ESTIMATED AND REAL VOLTAGE AND CURRENT VALUES (WEIGHTED VS. UNWEIGHTED)

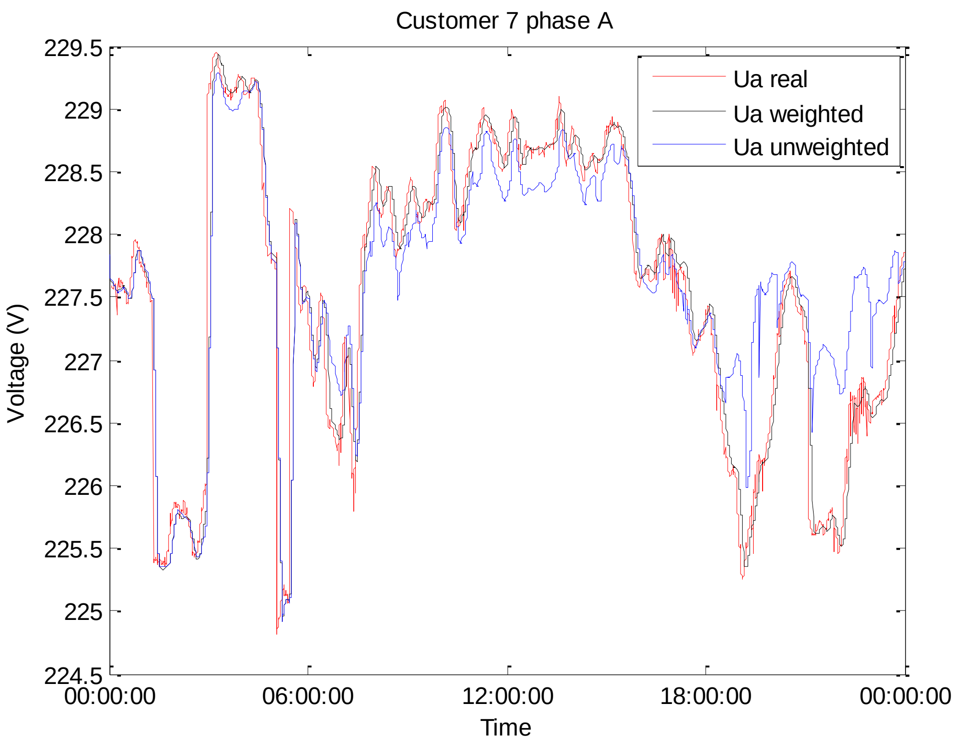

Figure 15 *Estimated voltages in phase a (weighted vs. unweighted).*

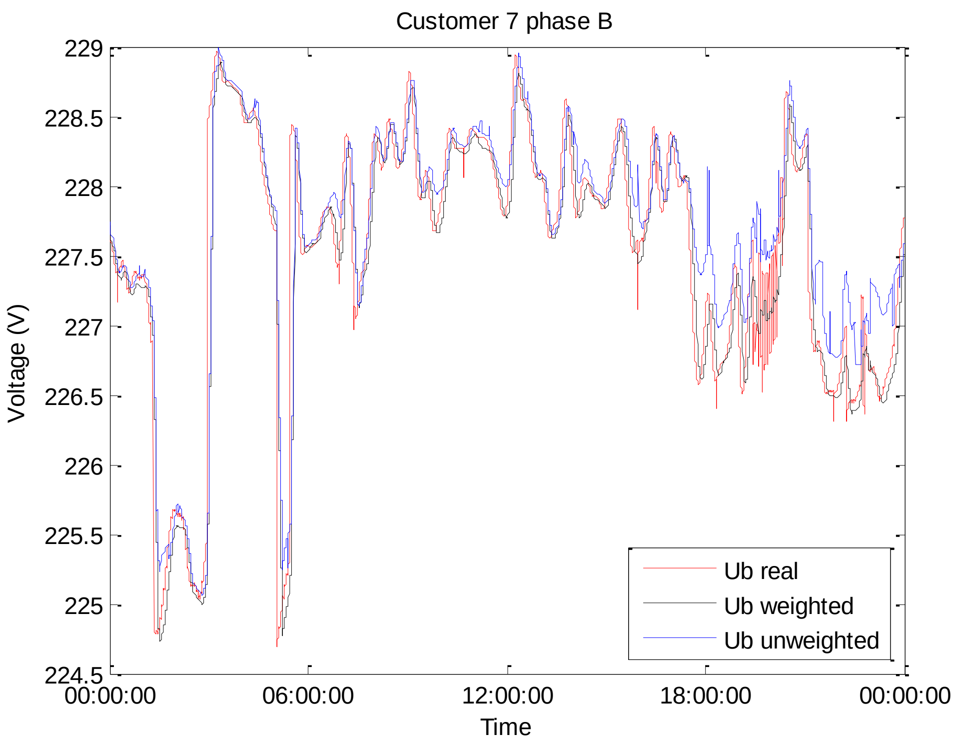

Figure 16 *Estimated voltages in phase b (weighted vs. unweighted).*

Figure 17 *Estimated voltages in phase c (weighted vs. unweighted).*

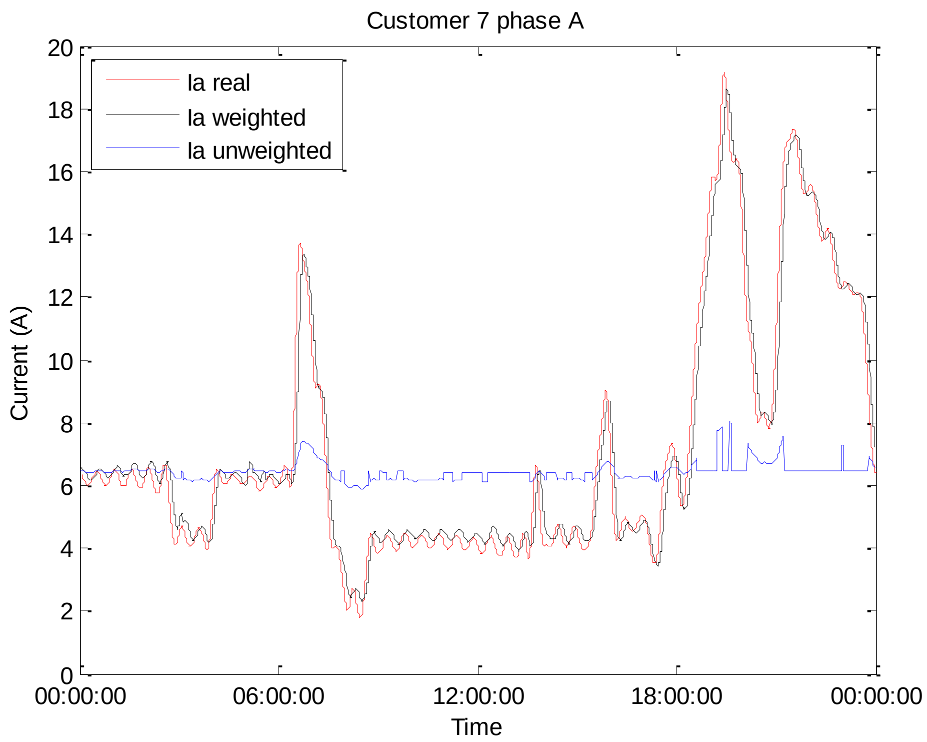

Figure 18 *Estimated currents in phase a (weighted vs. unweighted).*

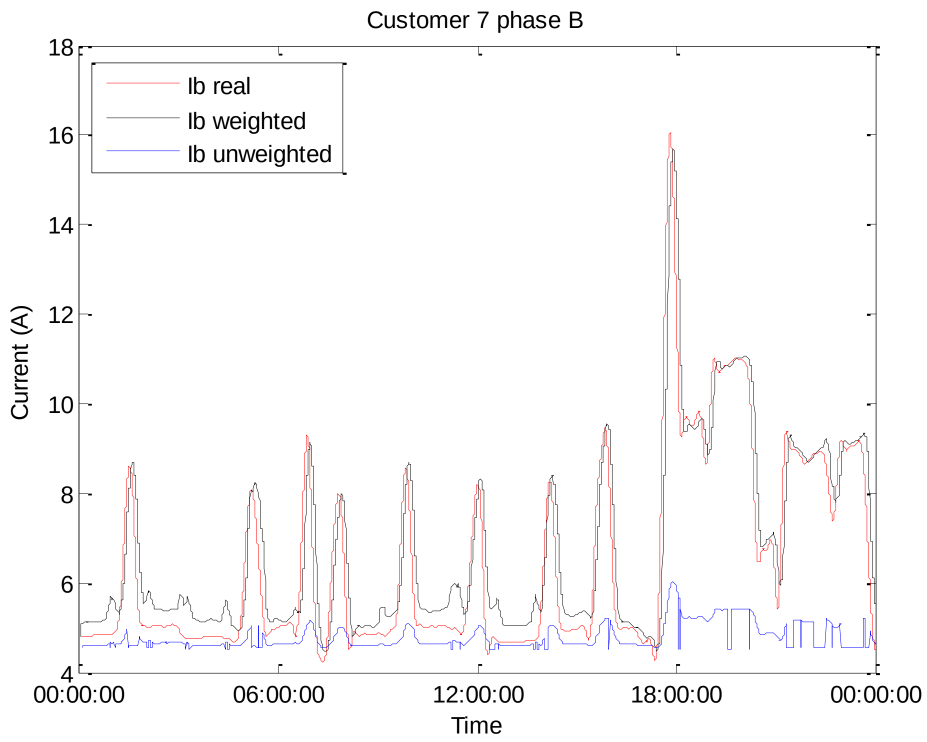

Figure 19 *Estimated currents in phase b (weighted vs. unweighted).*

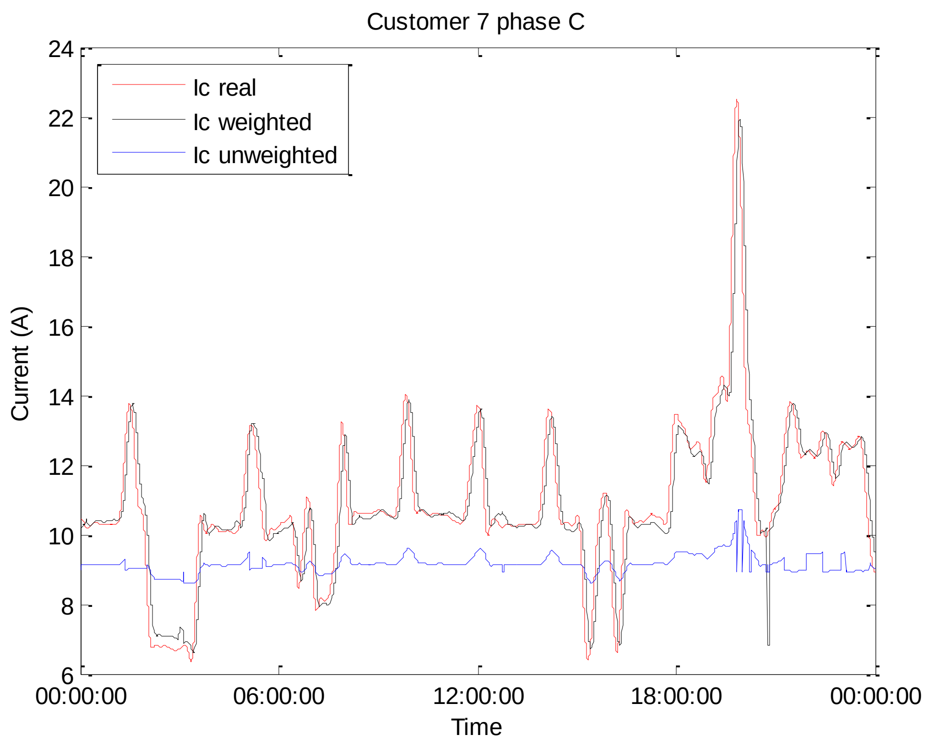

Figure 20 *Estimated currents in phase c (weighted vs. unweighted).*

APPENDIX 4 – FIGURES OF ESTIMATED AND REAL VOLTAGE AND CURRENT VALUES WITH DIFFERENT SMART METER READING FREQUENCY

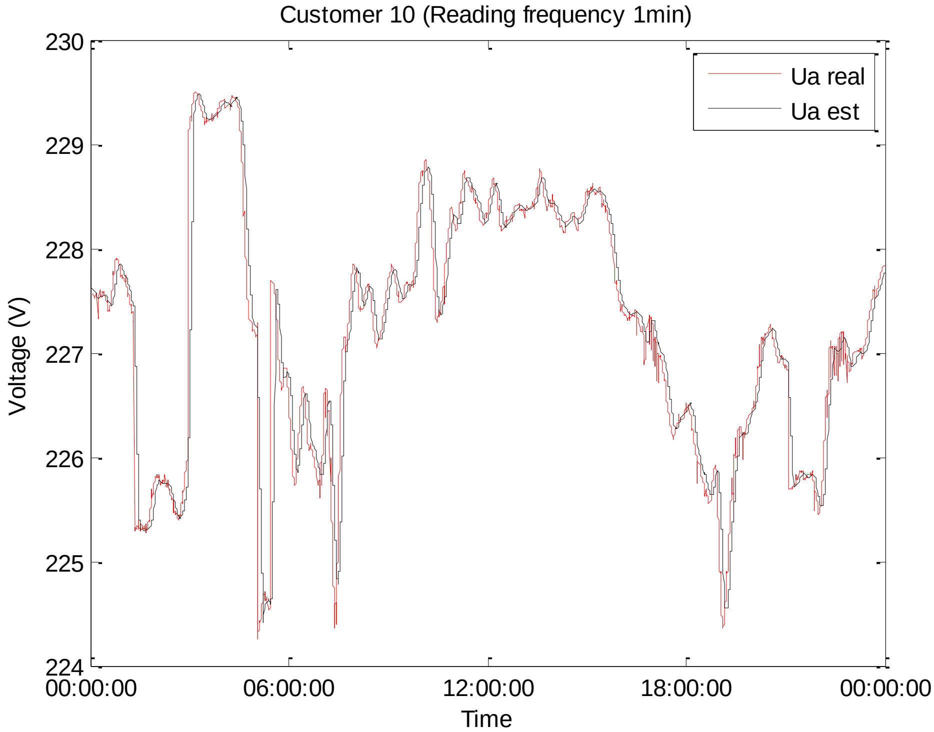

Figure 21 *Estimated voltages based on measurements with 1 min reading frequency.*

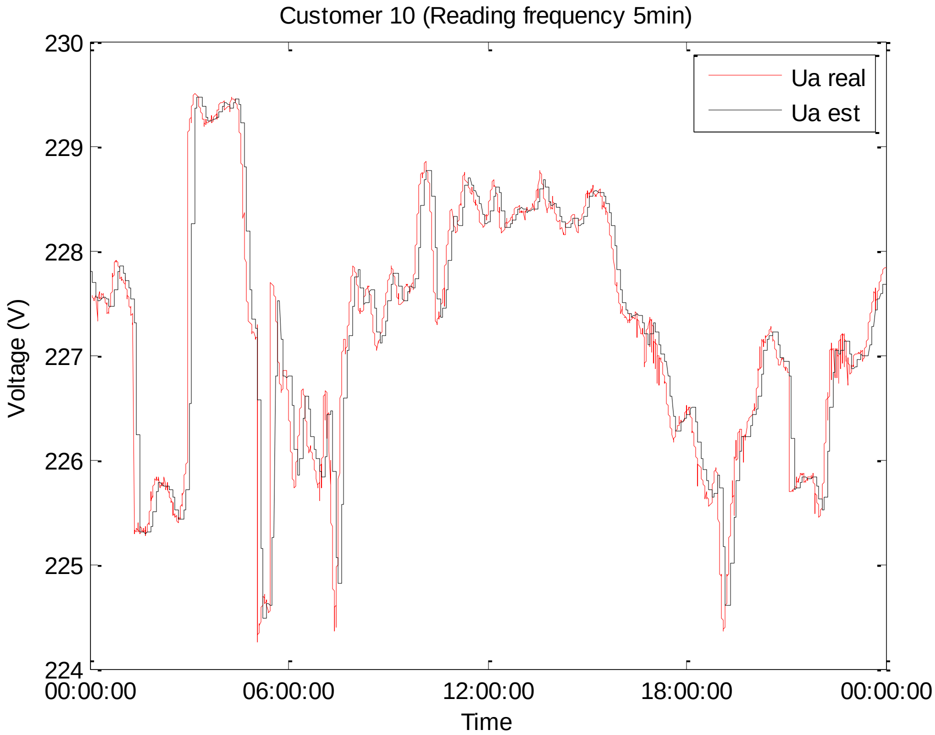

Figure 22 *Estimated voltages based on measurements with 5 min reading frequency.*

Figure 23 *Estimated voltages based on measurements with 10 min reading frequency.*

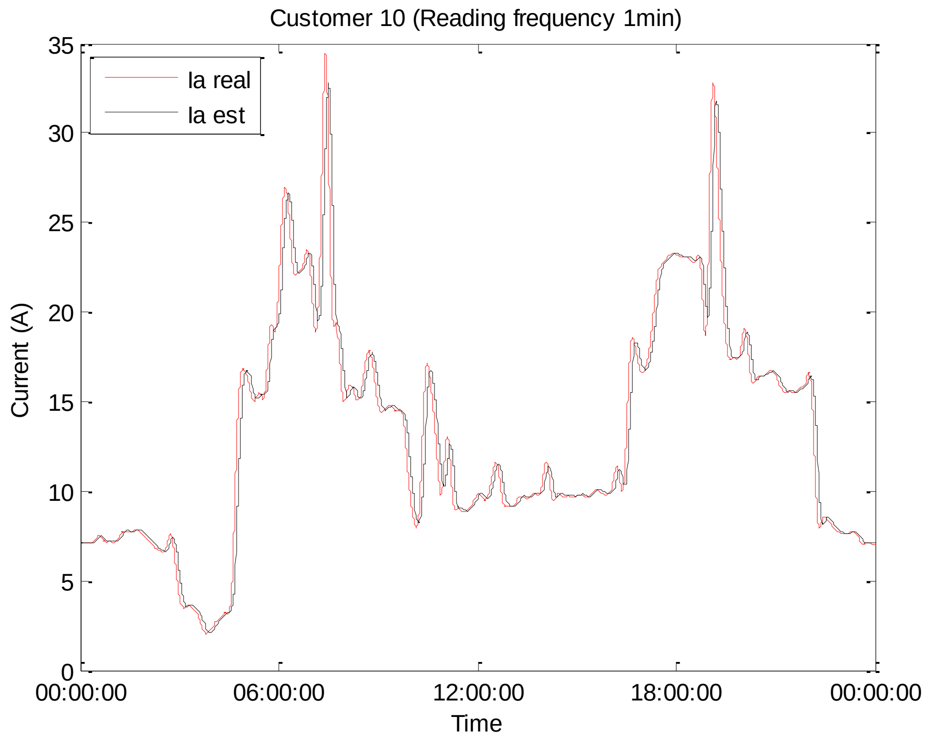

Figure 24 *Estimated currents based on measurements with 1 min reading frequency.*

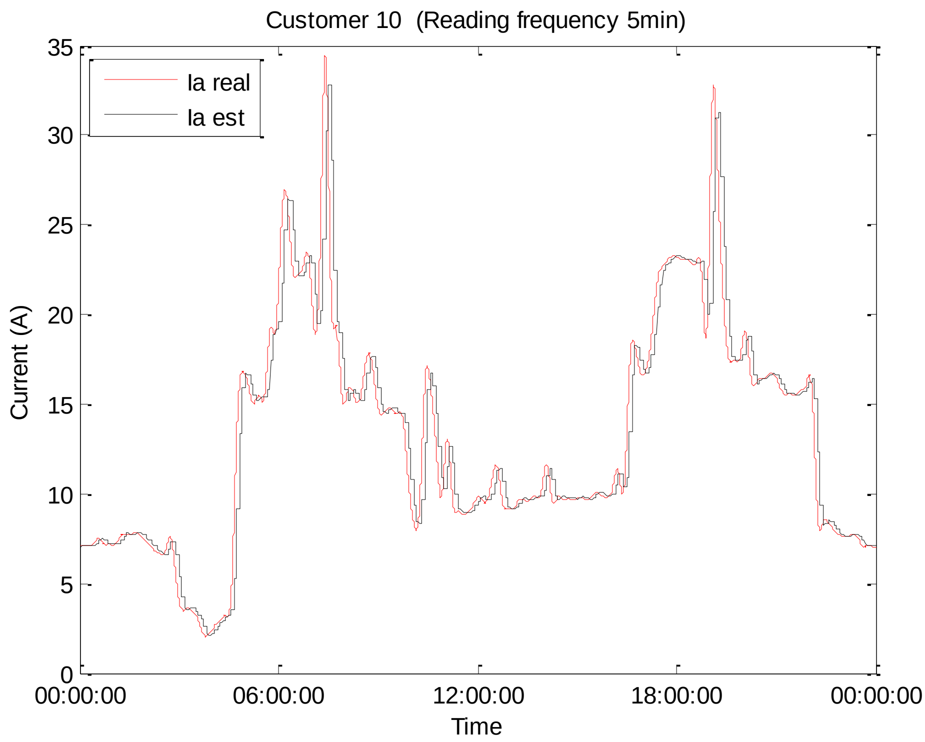

***Figure 25** Estimated currents based on measurements with 5 min reading frequency.*

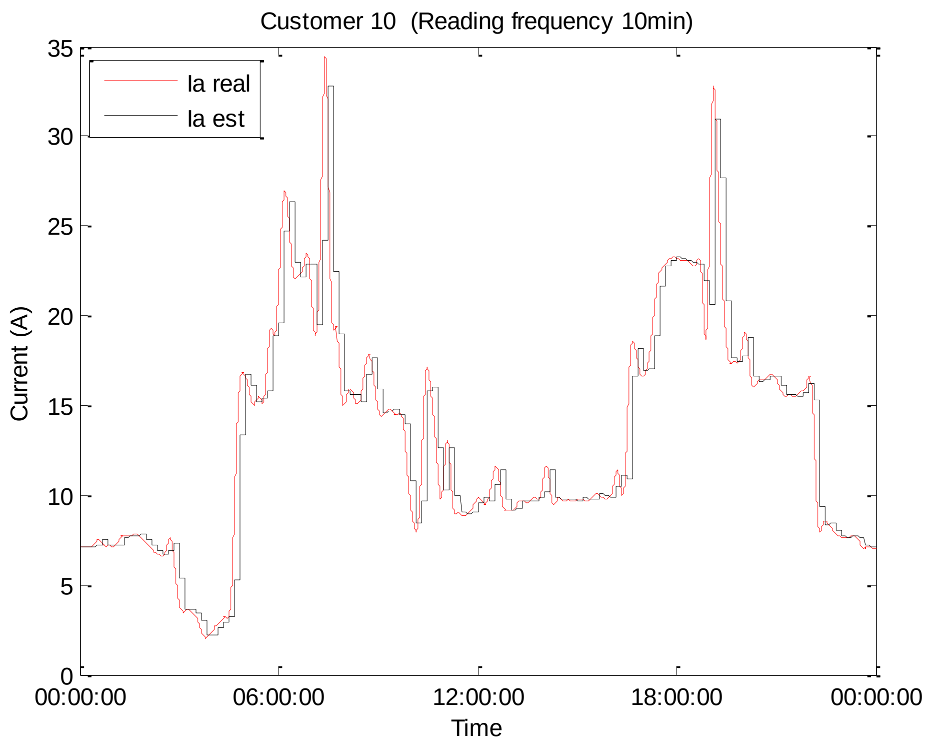

***Figure 26** Estimated currents based on measurements with 10 min reading frequency.*

APPENDIX 5 – FIGURES OF ESTIMATED AND REAL VOLTAGE AND CURRENT VALUES WITH DIFFERENT AVERAGING OF MEASUREMENTS

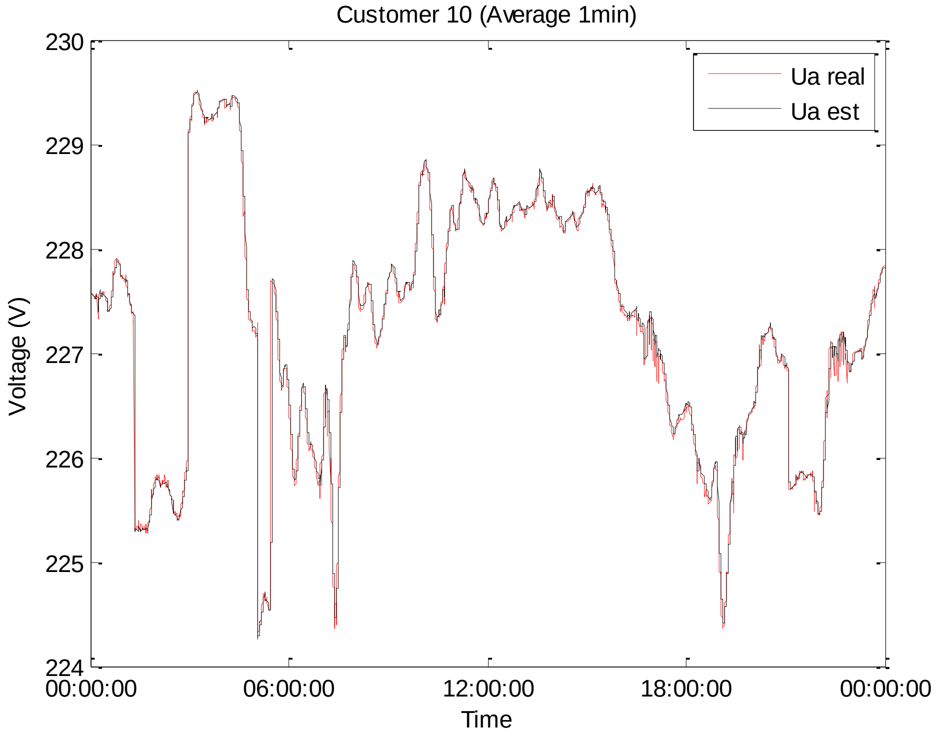

Figure 27 *Estimated voltages based on measurements with 1 min average.*

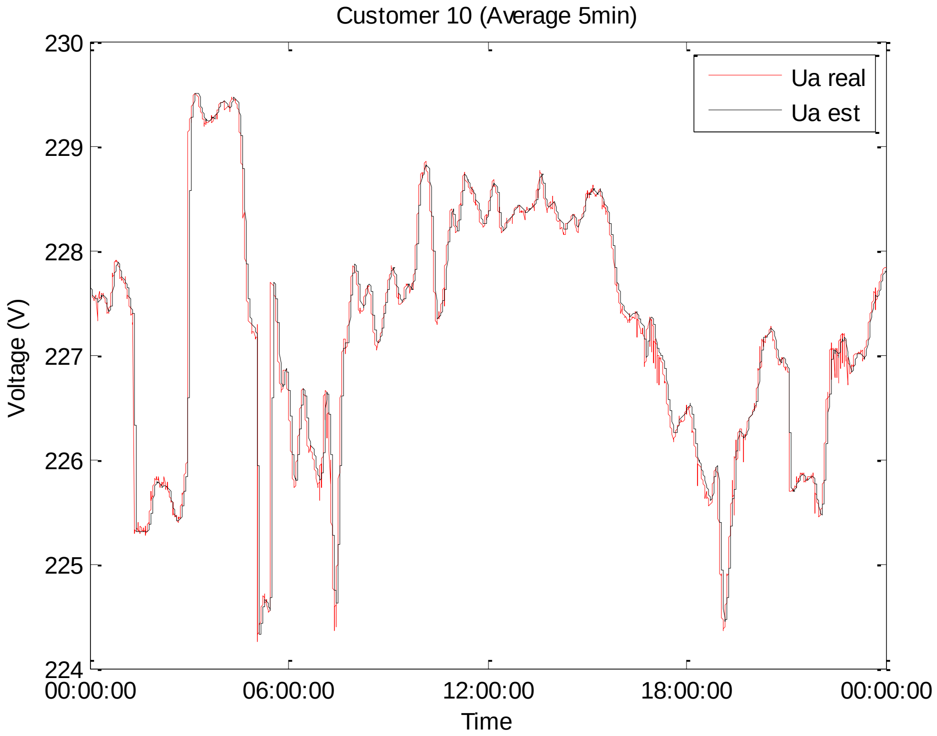

Figure 28 *Estimated voltages based on measurements with 5 min average.*

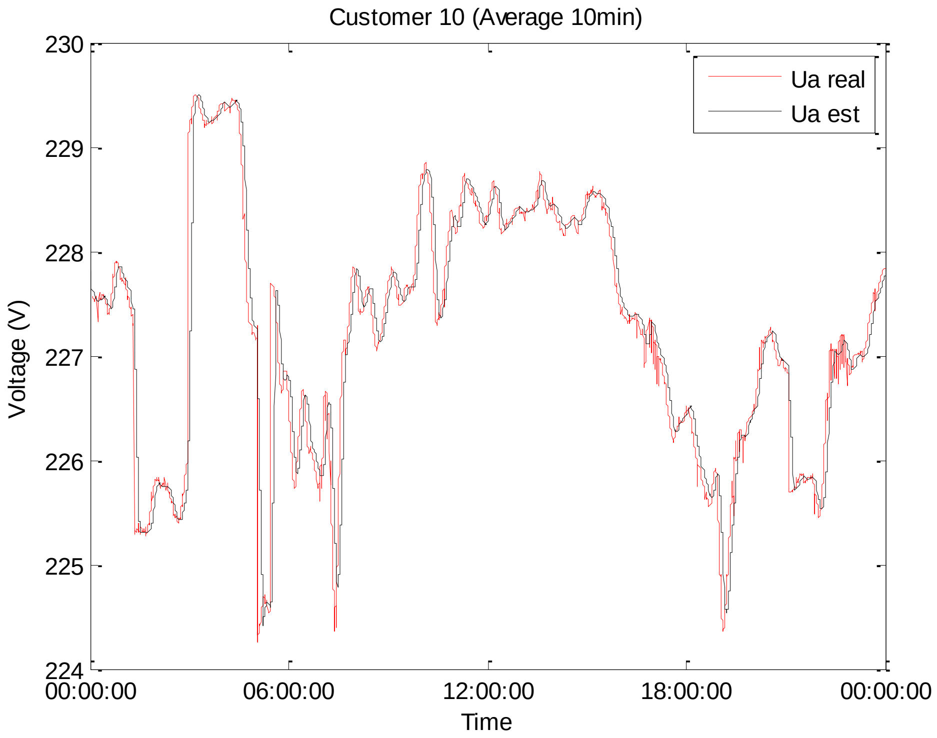

Figure 29 *Estimated voltages based on measurements with 10 min average.*

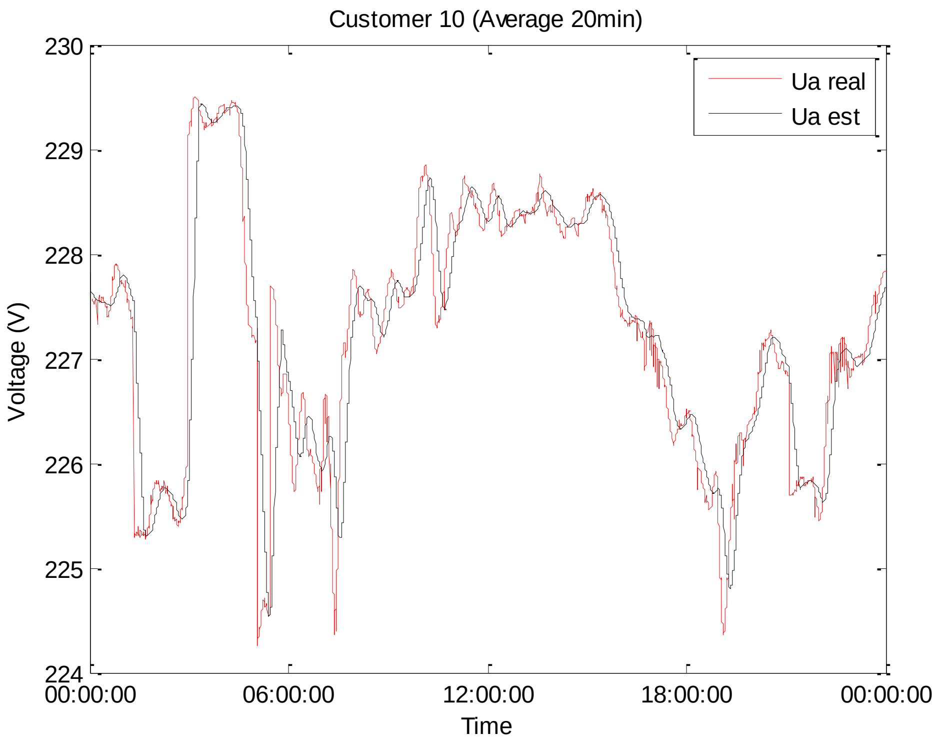

Figure 30 *Estimated voltages based on measurements with 20 min average.*

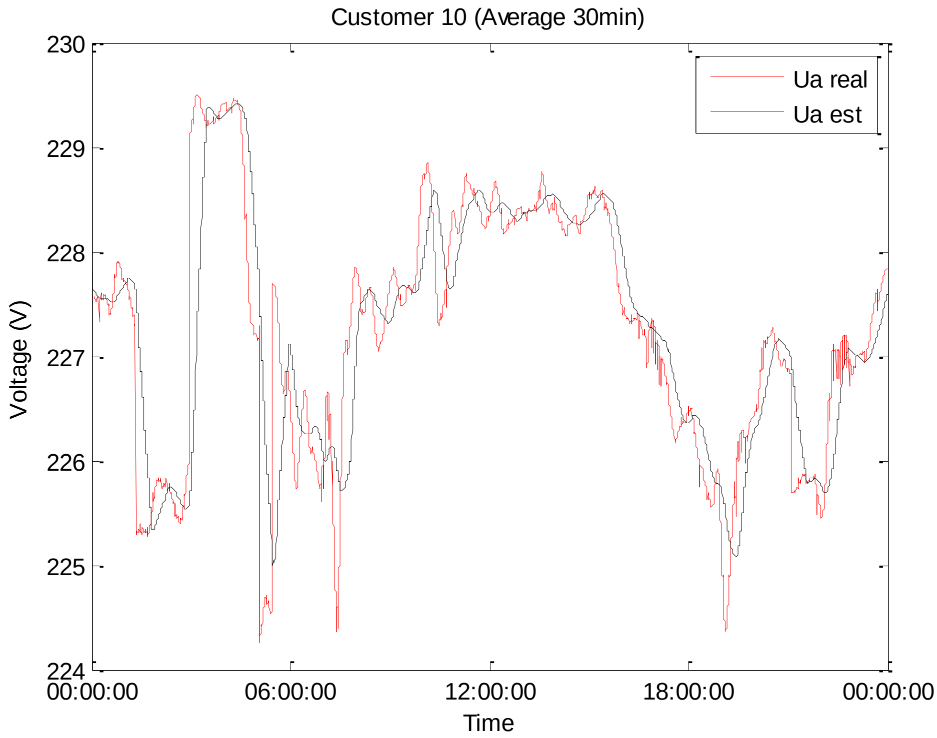

Figure 31 *Estimated voltages based on measurements with 30 min average.*

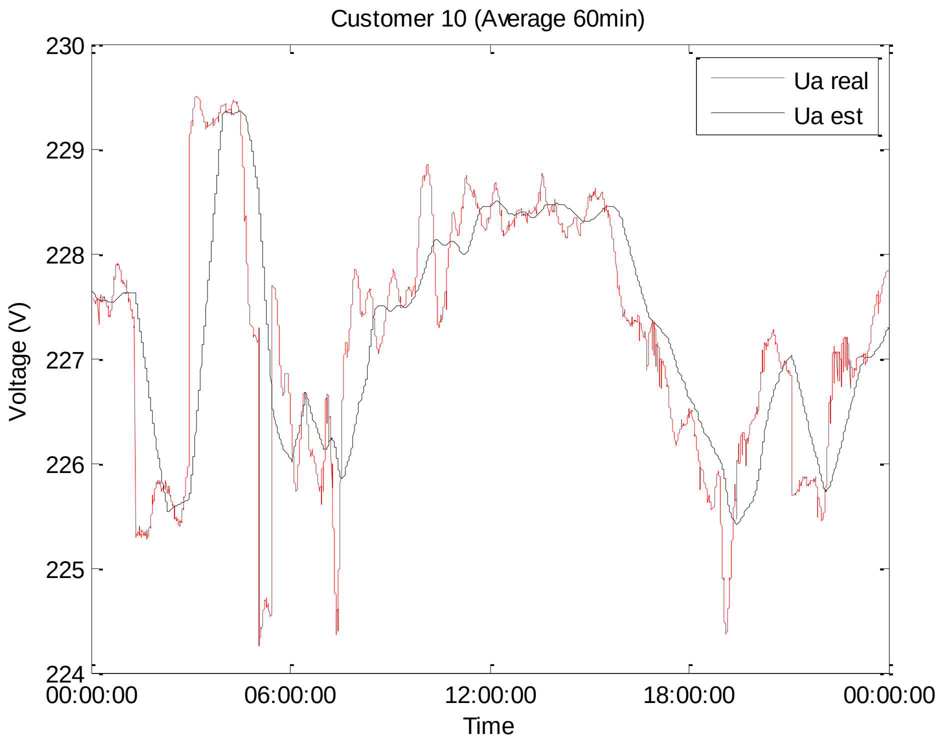

Figure 32 *Estimated voltages based on measurements with 60 min average.*

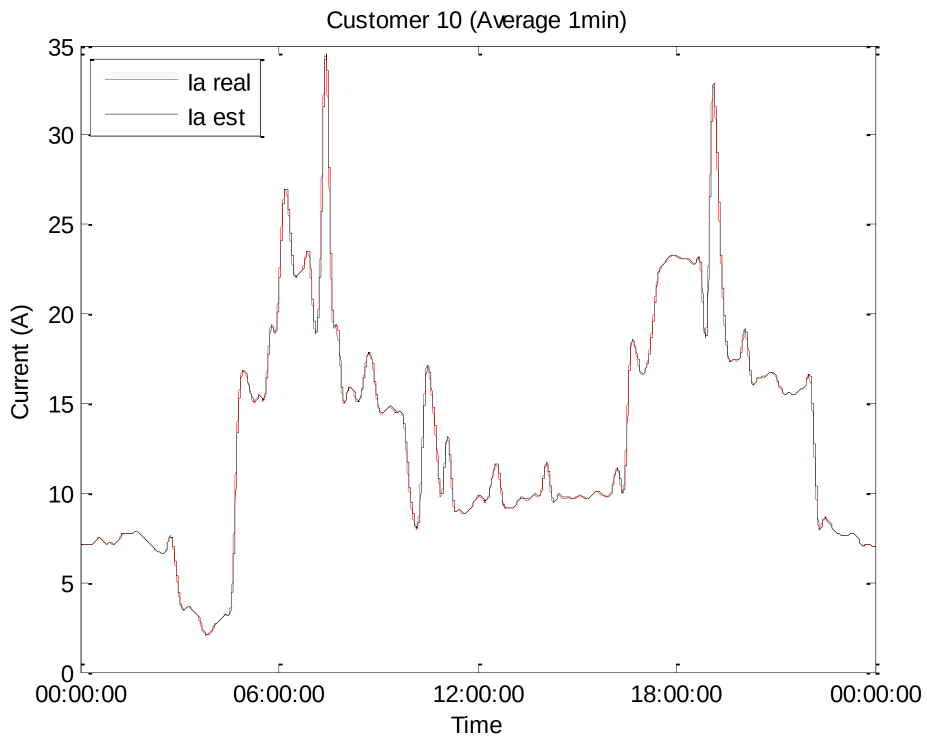

Figure 33 *Estimated currents based on measurements with 1 min average.*

Figure 34 *Estimated currents based on measurements with 5 min average.*

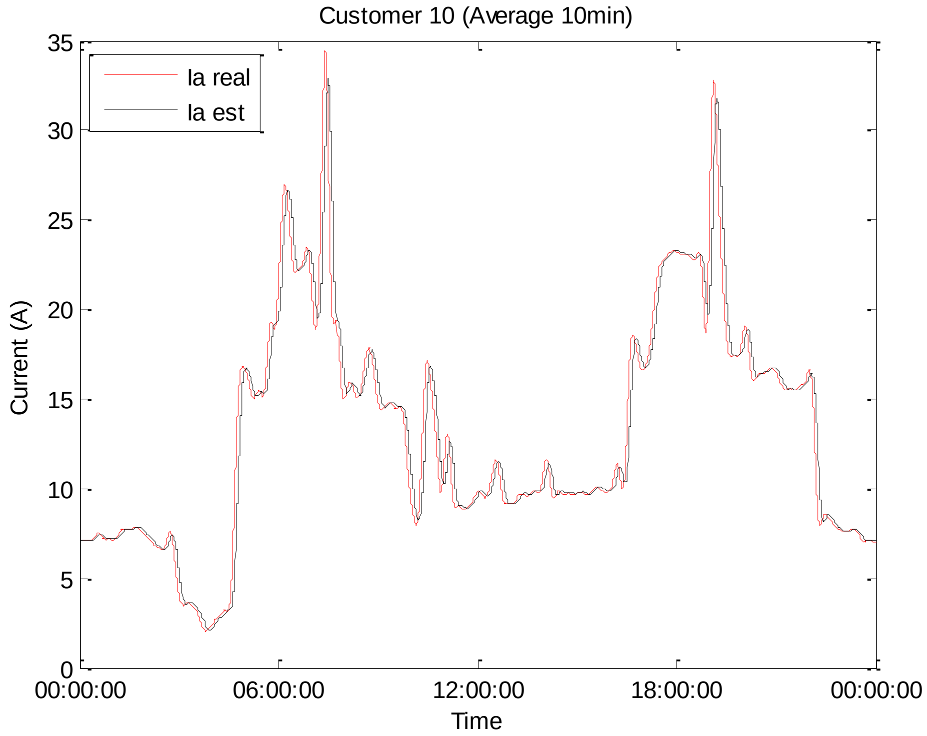

Figure 35 *Estimated currents based on measurements with 10 min average.*

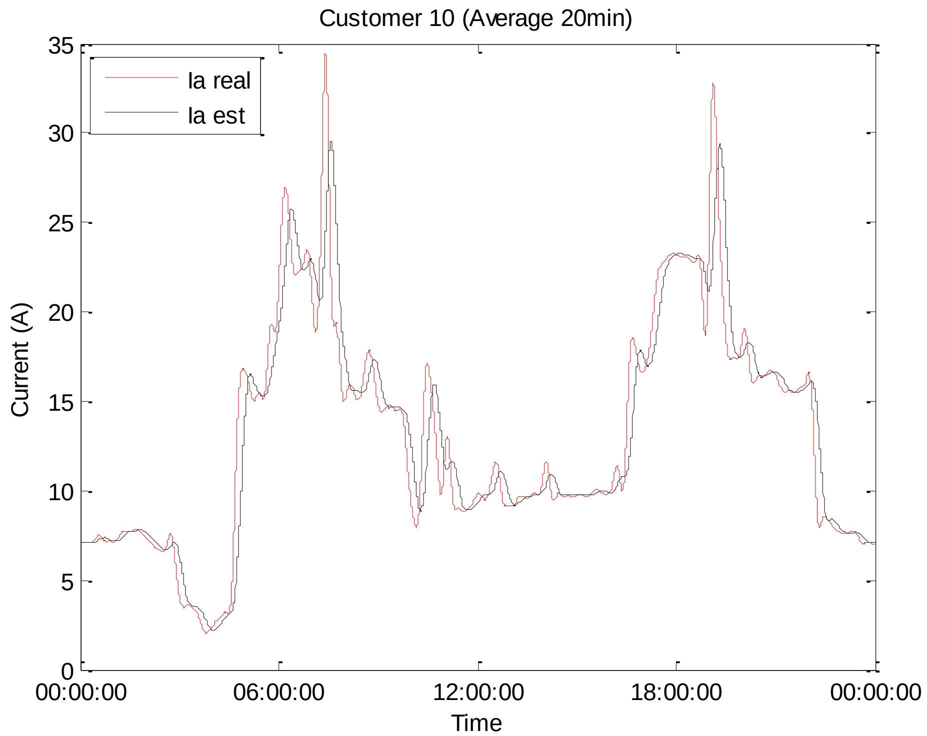

Figure 36 *Estimated currents based on measurements with 20 min average.*

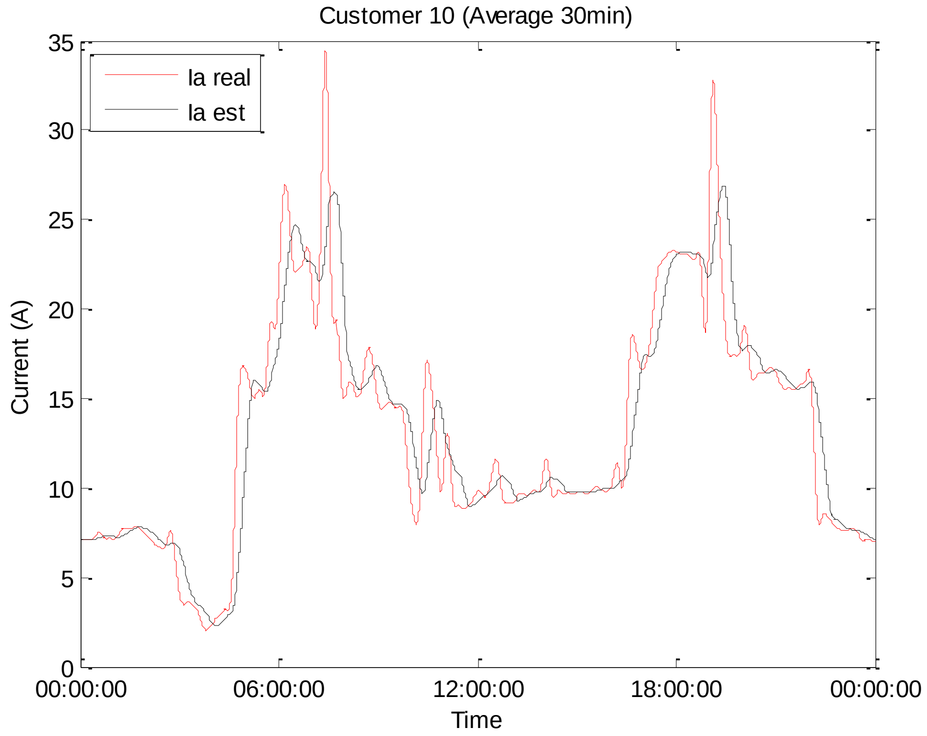

Figure 37 *Estimated currents based on measurements with 30 min average.*

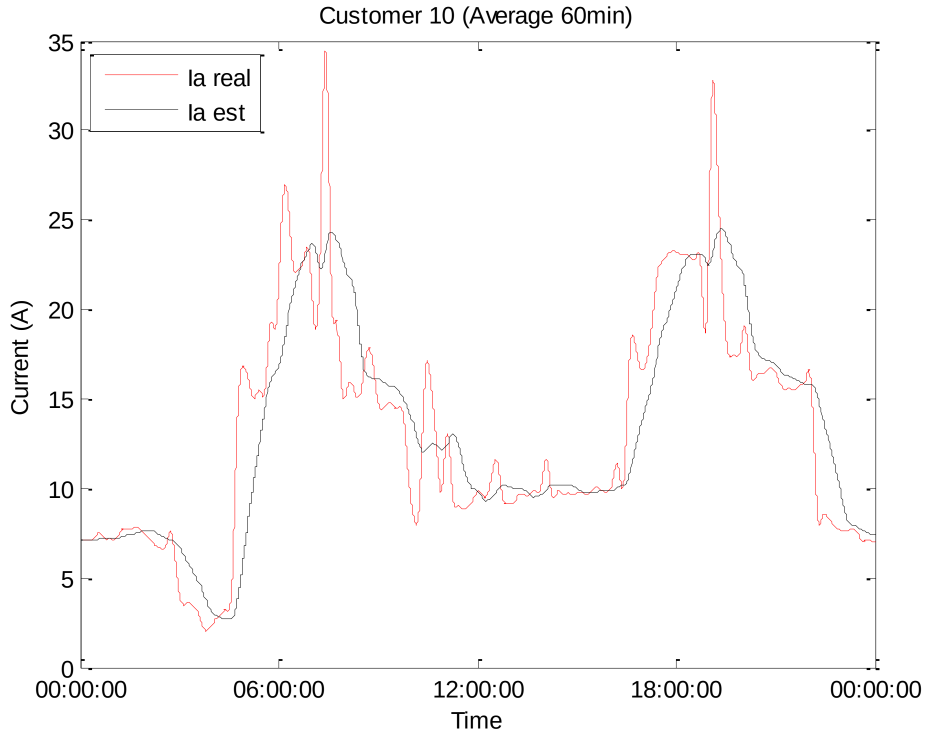

Figure 38 *Estimated currents based on measurements with 60 min average.*