Final report

Indhold

1.1 Project details

Project title	Determination of Automation Demands for Improved Controllability and Observability in Distribution Networks
Project identification (program abbrev. and file)	DECODE, file no. 12414
Name of the programme which has funded the project	Forskel
Project managing company/institution (name and address)	Aalborg University, Pontoppidanstræde 111,9220 Aalborg East
Project partners	Originally there were 6 partners **Aalborg University,** Department of Energy technology, Pontoppidanstræde 111, 9220 Aalborg East, project participants: Birgitte Bak-Jensen, Jayakrishnan Pillai, Karthikeyan Nainer and Basanta Raj Pokhrel **ABB A/S**, Håndværkervej 23, Fredericia, project participant: JaKob Kledal **Energimidt**, Tietgensvej 4, 8600 Silkeborg, project participant, Thomas Helth **HEF net A/s**, Juelstrupparken 16, 9530 Støvring, project participant Allan Jensen **Kenergy,** Grønningen 43 / 8700 Horsens , project participant Kenn Frederiksen **SYDENERGI Net A/S ,** Edison Park 1, DK-6715 Esbjerg N, Project participant Jacob Andreasen **Energimidt** and **HEF A/S** has merged to **Eniig**,

	Tietgensvej 4, 8600 Silkeborg, So by the end of the project there is a total of 5 partners including Aalborg University.
CVR (central business register)	29102384
Date for submission	31st October 2019

1.2 Short description of project objective and results

The project are related to development of a robust state estimation and control procedure for the distribution grid using as less measurements as possible analysing requirements and benefits gained by smart automation and analysing needed interfaces between the distribution and transmission system to enhance security and reliability.
A method for finding minimum and optimal placement of measurement devices is developed and used in state estimation procedures, which are verified with demonstrations. New control methods help minimizing power losses and increase the hosting capacity for integration of renewables using e.g. network reconfiguration, demand response and market aspects. Adaptive relay-protection are addressed to solve issues with varying short circuit levels in distribution grids. Finally, how to improve the interaction between the distribution and transmission grid to provide ancillary services is addressed.

Projektet er relateret til udvikling af en robust tilstandsestimerings- og styringsprocedure til distributionsnettet med anvendelse af så få målinger som muligt ved analyse af krav og fordele, der kan opnås ved smart automatisering og analyse af nødvendige grænseflader mellem distributions- og transmissionssystemet til at forbedre sikkerhed og pålidelighed.
En metode til at finde minimum og optimal placering af måleenheder er udviklet og anvendes i tilstandsestimeringsprocedurer, der er verificeret med demonstrationer. Nye styringsmetoder hjælper til at minimere effekttab og øge andelen af vedvarende energikilder der kan tilsluttes vha. fx. netrekonfiguration, fleksibelt elforbrug og markedsaspekter. Adaptiv relæbeskyttelse adresseres for at løse problemer med forskellige kortslutningsniveauer i distributionsnet. Endelig behandles, hvordan man kan forbedre interaktionen mellem distributions- og transmissionsnettet for at levere hjælpeydelser mellem nettene.

1.3 Executive summary

The DECODE project are focussed on development of a cost effective automation of the distribution grid, which is needed for an intelligent use of the grid in the future smart energy system, where electrification of the heating and transportation systems is expected and where more distributed renewable generation are integrated. The main goals of the project are development of a robust state estimation, control procedures and adaptive protection for the distribution grid using as less measurements as possible. Further, the project has analysed requirements and benefits gained by smart automation looking into needed interfaces between the distribution and transmission system to enhance security and reliability.

In the project a method is developed to find minimum and optimal placement of measurement devices performing real-time measurements for making the distribu-

tion grid observable. These real time measurements are used together with forecasted pseudo measurements found by artificial neural network forecast from data from existing smart meters measuring 15 min values in set up state estimation procedures. The observability check and state estimation are first documented by simulations, but in the end of the project, the methods are also demonstrated in a real grid applying new set up measurement devices and using smart meter data for private costumers. The methods are tested on MV as well as on LV grids.

New hierarchical control methods with three levels for the control are set up. The lowest level perform autonomous control using droop control based on local voltage measurement, to ensure that the voltage does not cross the allowed maximum og minimum limits. The middle level control gives set point values for the devices intra hourly based on need for intra hourly balancing. The upper level uses the day-ahead market for setting hourly set points for the devices the day before actual activation. The control methods uses advanced optimization methods and routines to find the lowest cost for the distribution company and costumers, and uses demand response to gain flexibility and network reconfiguration to minimize power losses and increase hosting capacity for integration of renewables.

As part of the automation of the distribution grid, also automation for fault situations are addressed. Adaptive relay-protection is used to solve issues with varying short circuit levels in distribution grids due to distributed renewable generation units, which are producing power stochastically. Both issues related to protection blinding and false tripping are illustrated both by simulation and by hardware in the loop test in laboratory.

Finally, current practice and expected challenges for the interface between the distribution and transmission grid are analysed and recommendation for future interaction between the distribution and transmission grid are set up. A detailed scenario for how ancillary services can be provided from the distribution level, to support balancing at transmission level operating the distribution grid within hosting limits is shown.

The conclusion is, that it is possible to use the existing measurement devices and only add few new measurement devices to have state estimation with sufficient accuracy at all nodes in the distribution grid. The found states can then be used in new set up control methods that ensures that the distribution grid can host more renewable generation and be able to gain demand response from individual components, which will help the distribution companies to have higher utilization of their grids and operating the grid closer to the limit. This might also postpone the need for network reinforcement. Further, the extended interaction between the distribution and transmission operators allows better possibilities for the distribution companies to provide ancillary services, which is needed to integrate more fluctuating renewable generation both at distribution level as well as on transmission level and at the same time ensure reliability and security in the grids.

1.4 Project objectives

Due to the increased penetration of renewable energy based distributed energy resources (DER) and expectation of increased usage of electricity due to electrification of the transport (electrical vehicles and buses) and thermal (heat pumps and electrical boilers) sector, the grid might realize periods with risk of congestion. These issues demands for solutions to have a better supervision and control of the grid, but at the same time this have to be a techno-economic feasible operation. Further, all the new penetration of dispersed generation and heavy loads have to be balanced also towards the overall operation of the transmission grid and could play a role in the existing/emerging energy markets, initiating a need for improved interface between the distribution systems operators (DSO) and the transmission system operators (TSO). These issues has lead to the following overall objectives for the project:

- To analyse the requirements and benefits of ***smart automation schemes and processes*** in the existing distribution management systems and to understand what is necessary to be newly installed and implemented in order to ***facilitate and achieve techno-economic efficiency***.
- To develop and verify ***novel and robust state estimation procedures*** and models for ***control and protection solutions*** which accurately measure and are able to affect the system states of grid assets in electricity distribution networks.
    - The solutions are applied to produce an optimal distribution grid management system for DSO operations that ensures the ***best utilisation of assets and integration of renewable based DERs*** in a sustainable manner, and at the same time keeping the ***automatization and thereby the costs to a minimum***.
- To investigate the scope of appropriate ***interfaces between DSO and TSO*** for system security and reliability.
    - The solutions developed in this project for improved observability and controllability of the active distribution grids is applied to ***enable the active participation of DERs*** and loads in energy markets and ancillary services.

The project started on April 2016 and stopped by October 31st 2019. The work was divided into 8 work packages as shown in the figure 1. WP1 focus on how to set up the system architecture for state estimation and control of the future distribution grid. WP2 focus on the control part which is of hierarchical structure and will control the assets in an optimal way. WP3 focus on defining full observability of the distribution followed by procedures for state estimation in the observable grid. WP4 looks into protection of the future distribution grid, where there might be risks of false tripping and blinding. WP5 merges the found results from the state estimation, control and protection WPs into an overall distribution management system. WP6 have real demonstration of some of the issues dealt with in WP2-5. This includes verification of state estimation techniques in the real distribution grid both at MV and LV level, but also laboratory verifications of some of the protection issues dealt with in WP4 on a real time digital simulator (RTDS system) with hardware in the loop coupling of real protection relays. WP7 focus on needed DSO-TSO interactions in the future automated distribution grid. Finally, WP8 is the WP for the overall management of the project, where the progress of the project and risks in the project are managed.

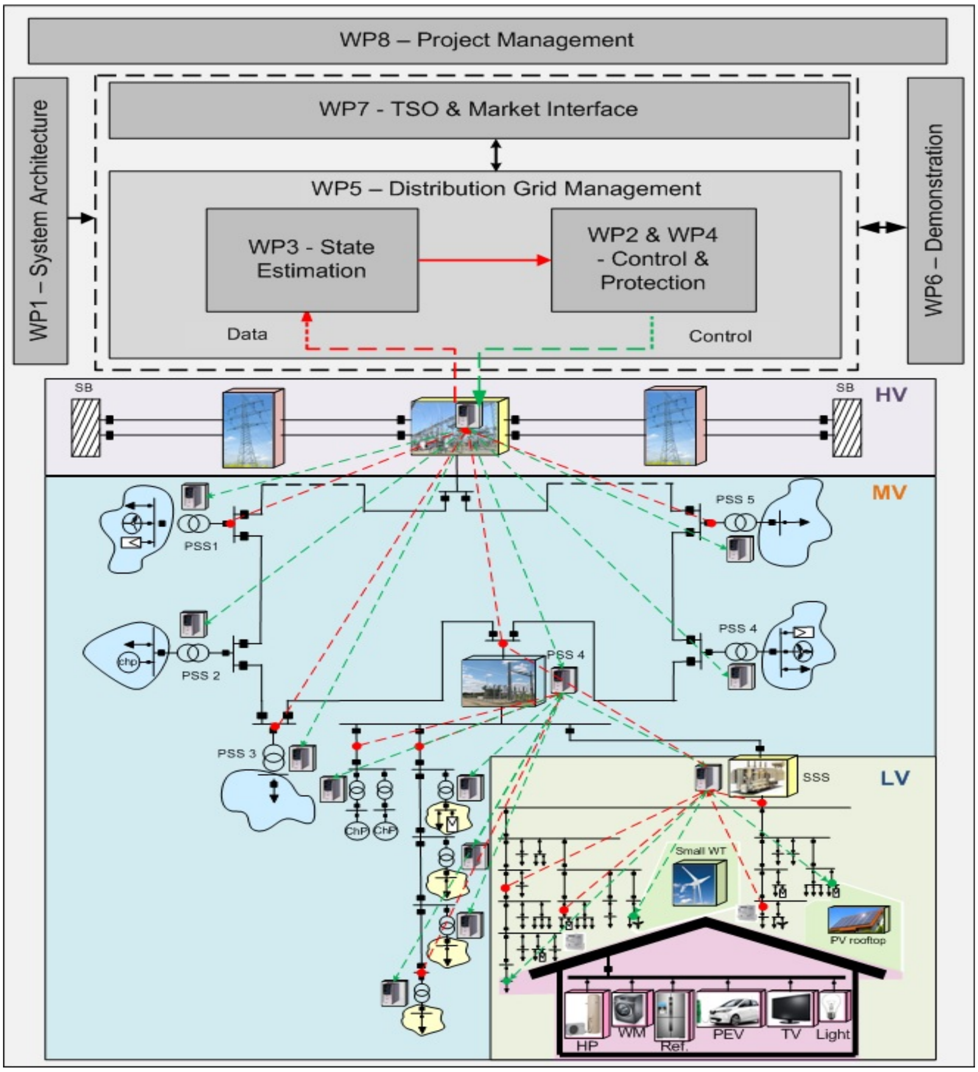


Figure 1. Conceptual framework for the project as given in the application.

During the project period some of the partners merged, that is HEF and EnergiMidt merged and became Eniig. This gave a slight concern about where to make the demonstration, since this was a part of the project work from EnergiMidt. But in the end, a nice location in the former EnergiMidt area were found for the demonstration. Also the contact person at ABB were shifted, which gave a period with little contact to ABB, but when the demonstration part should start, they became very active again, and helped a lot during the test period, with providing equipment, helping with data transfer etc. The project progressed more or less as planned according to the original Gantt chart. However, there were a minor delay due to paternity leave of one of the PhD candidates, and also the verification of the state estimation procedure in the real grid took longer time than planned due to a lot of difficulties communicating the measured data in the grid to Aalborg University.

The above description also focus some of the risks seen in the project, which are also pointed out in the project application, where the following risks are mentioned:

- Withdrawal of partners due to conflicts of interest, financial crisis etc.
    - This risk was expected to be low, but during the project time we saw the merging of the two of the DSOs, which could have caused delays.
- Failure/deviations to achieve a project milestone, budget and deliverables on time

    - This risk was also expected to be low, but it actually happened as mentioned in two ways:
        - We had a slight delay and one month project extension due to paternity leave from one of the PhD candidates.
        - The actual demonstration part regarding the verification of state estimation in real grid was delayed due to problems with the actual set up, but mainly also due to problems in sending the measured data to Aalborg University.
    - In the end these delays caused only minor problems, since the PhD student involved in the state estimation did other tasks in the waiting time, and it was only one month delay of the whole project due to the paternity leave, leaving also room for catching of with other minor delays.
- Drop out of PhD student or Postdoc
    - The risk was mentioned to be low. The project group found good candidates, and they were focused on getting their PhD degree, so after a short period after their arrival, the supervisors were confident that this would not happen.
- Failure to promote and market project results
    - This risk was also expected to be low. There was a clear dissemination plan from the beginning of the project, and also milestones were set up accordingly, so this risk were mitigated discussing dissemination at out regular meetings in the project group.
- Market development and standardization risks
    - This risk in this area was also expected to be low, since the project is a research and development project, more than a project intended for new products and demonstration of these.
- Failure to integrate simulation models into lab set-up/prototypes, equipment/software malfunctioning
    - The risk was expected to be low, and due to help by experienced people in the laboratory, also this part worked well during the project period
- The final outcome does not reflect consistent estimated results.
    - The risk was expected to be low, and also the verification of the methods set up in the project reflects that the simulation results can be justified.
- Testing the distribution management strategies in on-site grid
    - This part had an expected risk of medium, and it was also here that we had more delays than expected, due to problems in setting up the physical equipment and especially transferring the data from the on-site tests to Aalborg University. The data in the end also showed periods with failure in the data recording. But anyway it gave very useful information for the practical demonstration of the set up state-estimation method and also values which can be used for verifying the forecast methods applied in the project.

So in general the risks were nicely mitigated during the project period and only one months extension were needed for the project period. Besides this the milestones were realized more or less according to the plan and the final demonstration in the grid and in laboratory were finalized with a slight delay, but within the slightly extended project period.

1.5 Project results and dissemination of results

As mentioned above the project has been divided into 8 WPs defining the overall work and deliverables to be expected in the project. However, the main technical activities to fulfil the project objectives are done in WP1-WP7 for which there also are technical reports for each of the WPs made as deliverables [1-7]. Further, the results have been documented in two PhD thesis [8,9] and by a total of 13 published conference and journal papers [10-22].
I this report is has been decided to group the results according to the set up goals and objectives for the project and not organize it according to the WPs. Therefore, it this part of the report is divided into the following subsections.

- 1.5.1 Requirements and benefits of smart automation schemes and processes
  - State of the art for exiting practices, set up of use cases and the system architecture is the contribution of this part.
- 1.5.2 Novel and robust state estimation procedure
  - Observability and state estimation procedures including demonstration in the real network grid is reported.
- 1.5.3 Models for control solutions
  - Methods for hierarchical control of the distribution is described
- 1.5.4 Protection and network reconfiguration
  - Methods are described and results from laboratory experiment are used to justify the results.
- 1.5.5 Interfaces between DSO and TSO for system security and reliability.
  - Description of the evolvement needed at the borderline between DSO and TSO

1.5.1 Requirements and benefits of smart automation schemes and processes

This work has started with work on a review of existing practices for the control of the distribution grid and expectations for the future challenges and requirements to be able to achieve an active distribution network (AND). The work was initiated by the Cigre working group C6.25 report about "Control and Automation Systems for Electricity Distribution Networks (EDN) of the future" [1]. A lot of state of the art review was also done concerning system architecture, observability and state estimation, forecasting, advanced distribution management systems, control in DSO systems including hierarchical control and demand response methods, utilization of battery energy storages, voltage control, optimization techniques, integration of renewables and utility interface and coordination between DSO and TSO, adaptive protection and network reconfiguration [8, 9]. Also state of the art review can be found in all the produced papers [10-22]. Based on this state of the art work, use cases for the project were set up at discussed with the partners, to ensure that they were realistic and relevant. The following use cases were identified:

- Forecasting
- Distribution state estimation (DSE)
- Voltage/Var control
- Demand side management
- Adaptive protection
- Intelligent reconfiguration
- Application of energy storages
- Dynamic rating of lines and transformers
- Loss minimization
- Advanced distribution management system (ADMS)
- Improved TSO-DSO interface

[1] Control and Automation Systems for Electricity Distribution networks (EDN) of the future, Cigre/Cired joing working group C6/B5.25/CIRED, Cigre technical brochure 711, December 2017

The use cases set up is shown in the below figure 2, and here it can be seen how some of the use cases are related to some of the other use cases, for instance the forecast use case is related to the DSE use case, which again are used in the hierarchical control structure (the blue box use cases).

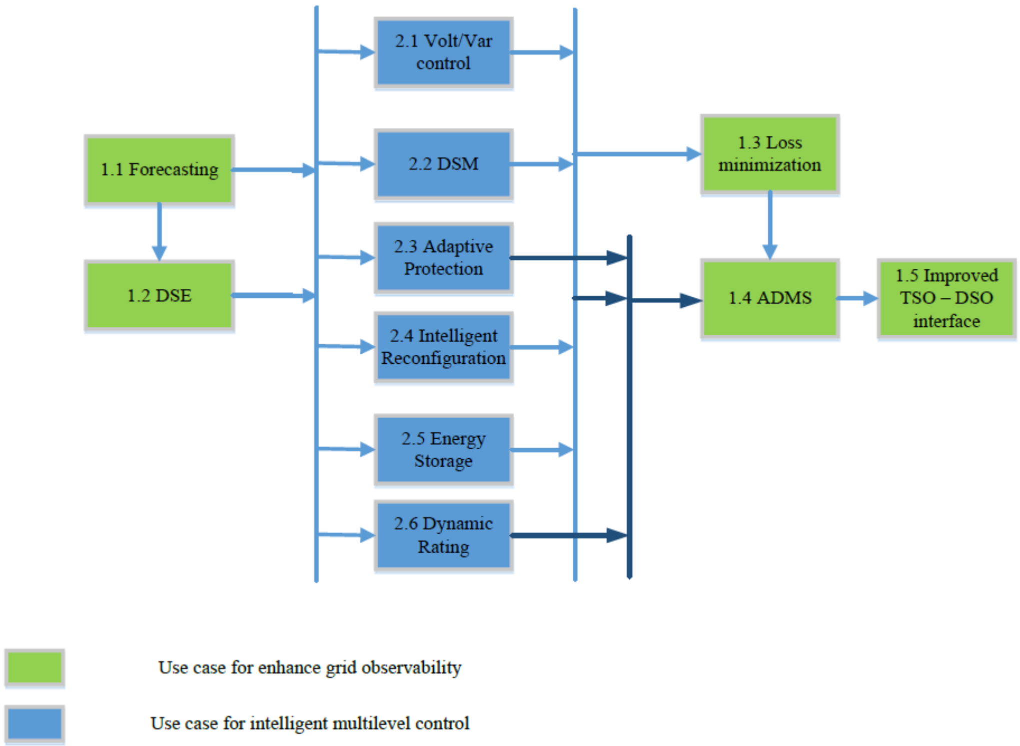


Figure 2. Overall system lay-out based on use cases [1].

The major actors (Market, prosumers, DSO, TSO) are identified for the different use cases as given in figure 3.

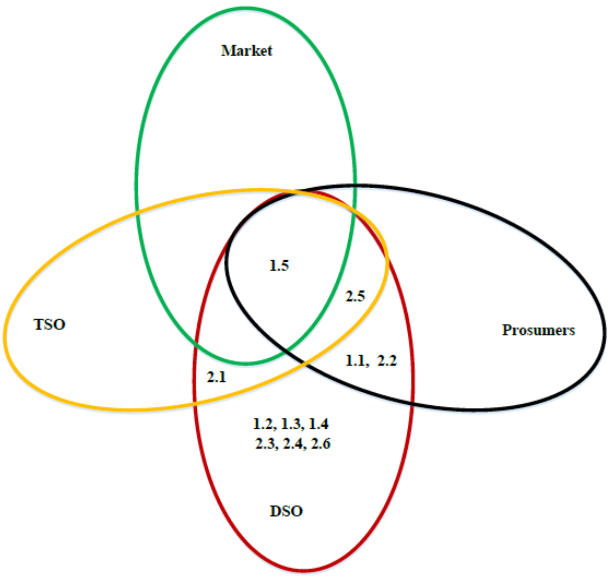


Figure 3. Major actors in the set up use cases [1]

More details of the actors and how they benefit from the different use cases can be found in [1].
Based on the use cases three main challenges for the control of the distribution grid is set up in [9] which are:

- Grid congestion management (both seen in relation to high penetration of renewable power generation and due to lack of proper TSO-DSO interface.
- Optimized operation of distribution grids looking into the ability to deliver power within the network constraints at minimum operating costs.
- Resilient operation of grids meaning ability to overcome power variations from loads as well as generation.

This leads to the following desired control functions for the ADMS in AND as shown in figure 4.

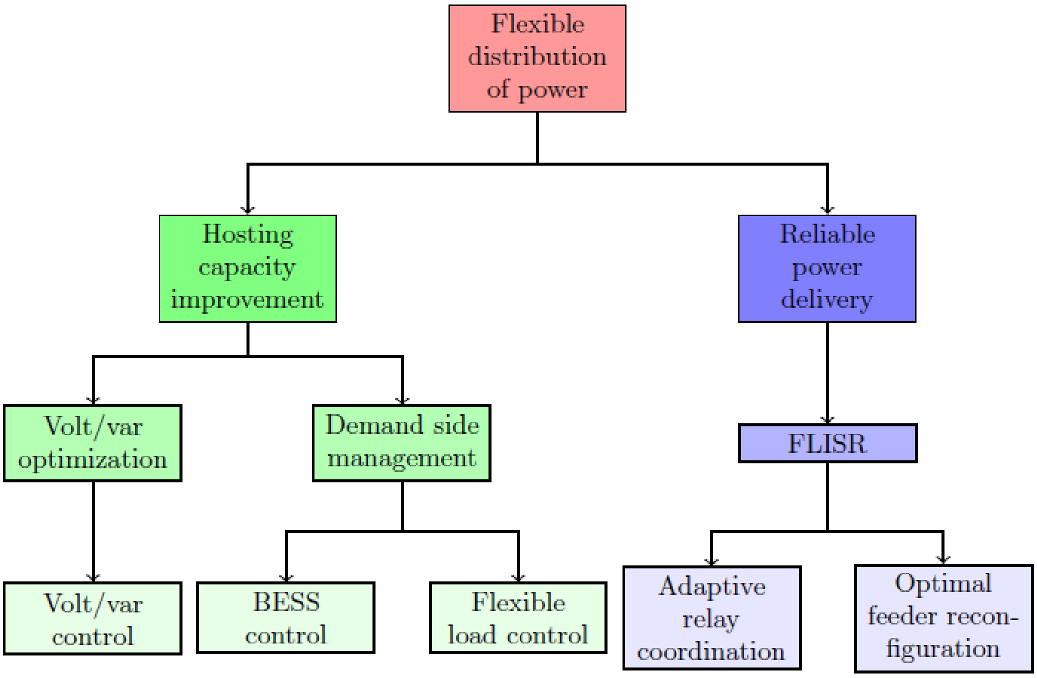


Figure 4. Desired function for the ADMS system [9,17] (FLISR= fault location, isolation, and service restoration)

A hierarchical control scheme to manage the desired function given in figure 3 is set up as shown in figure 5. More information of this control with the different levels of control will be given in section 1.5.3.

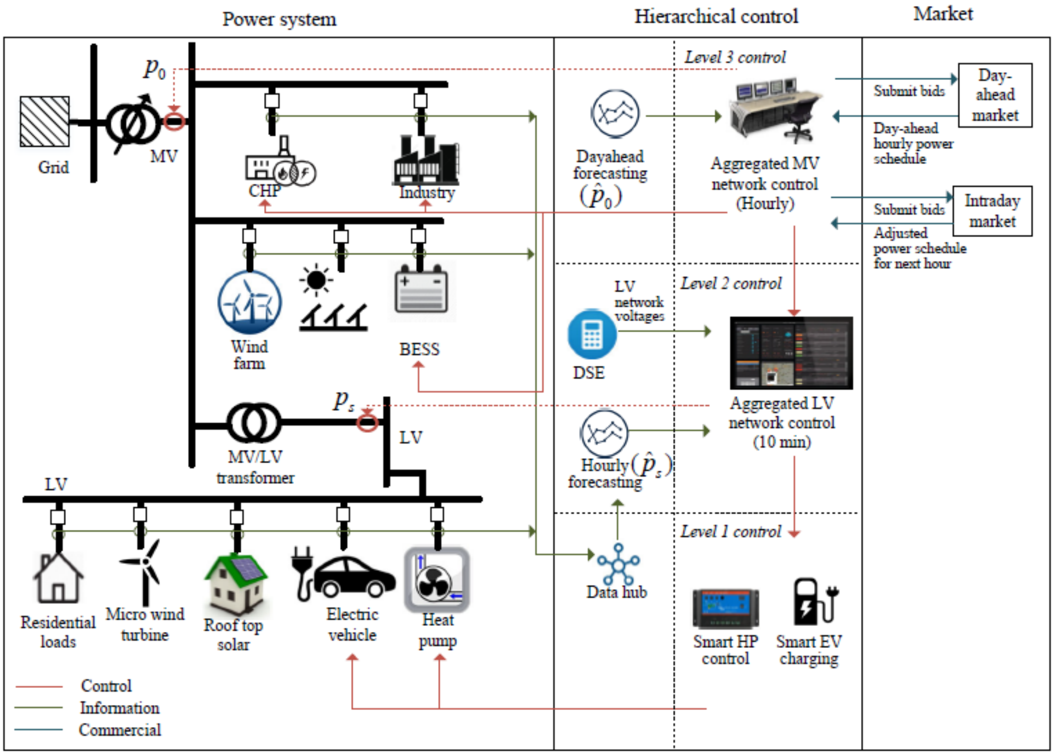


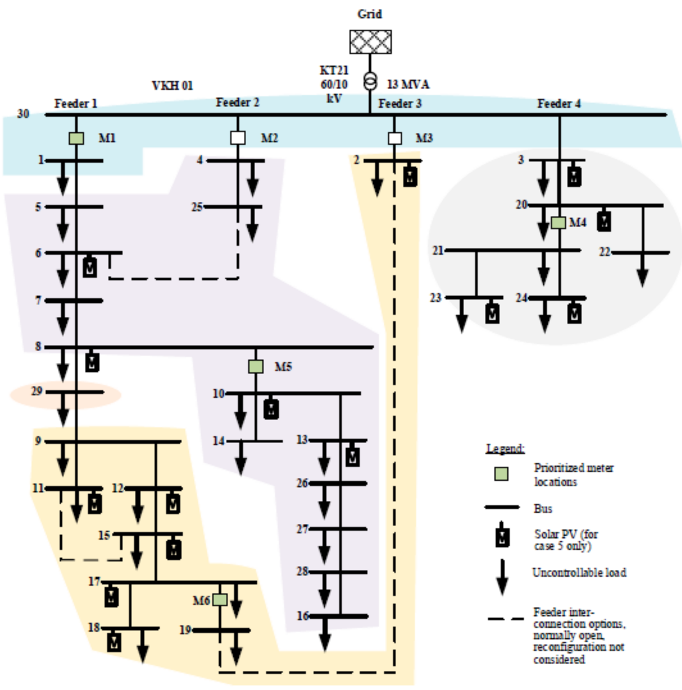
Figure 5. Schematic diagram of hierarchical control of the distribution grid. [9,17]

1.5.2 Novel and robust state estimation procedure

This part is based on [3, 8, 10, 11, 12, 13, 14, and 16]. The background for this part of the project is, that the DSOs has limited observability and knowledge of the actual status of the distribution grid, especially at MV level, since only few measurement devices are placed here. At the LV level more information can be gained using information from the smart meters installed at every costumer. However, this is not applied for status information and control today, and it is for sure not done in real-time since only quarterly or hourly values are collected for billing purposes. Further, observability and the following state estimation is also needed for many of the future control purposes in the DSO grid to ensure demand response and integration of renewables. Finally, state estimation is also an important feature for the TSO-DSO interoperation, to ensure balancing in the overall grid and provision of ancillary services. At the same time it is very costly to set upa lot of communication lines, and there the idea of the project is to find a solution with as less real measurement as possible. Therefore, the following research questions has been set up in relation to observability and state estimation [8]:

- How to develop a new network observability model that can observe the network and be able to estimate the network state accurately utilizing minimum key real measurements?
- How to address the interoperability and coordination challenge for utilities and market in emerging scenario?

A network grid is said to observable if all parameters (voltage, current, power etc) can be estimated at all nodes based on available measurements. I this project as mentioned the idea is to find a method to gain observability with as less measurements as possible. In the project first step is to divide the grid into observable islands as shown in figure 6 if the grid itself is not observable. Based on these island the minimum meter allocation is found, typical at nodes/buses to which more branches are connected.



Bus No.	Maximum load in kW at eac bus	PV generation equal to 20% of maximum load at each bus in kW (for case 5 only)
1	450	0
2	288	58
3	1019	204
4	72	0
5	288	0
6	36	7
7	36	0
8	72	14
9	144	0
10	36	7
11	742	148
12	288	58
13	180	36
14	252	0
15	227	45
16	18	0
17	288	58
18	1246	249
19	1289	0
20	227	45
21	144	0
22	144	0
23	227	45
24	144	29
25	36	0
26	144	0
27	72	0
28	36	0
29	144	0
30	0	0

Line	Length in meters
30-1	5555
1-5	180
5-6	829
6-7	763
7-8	919
8-29	145
29-9	673
9-11	2153
9-12	365
12-15	1333
15-17	946
17-18	2710
17-19	3994
8-10	715
10-14	2773
10-13	4961
13-26	779
26-27	452
27-28	725
28-16	717
30-2	852
30-3	94
3-20	4866
20-21	287
20-22	137
21-23	247
21-24	890
30-4	2146
4-25	1607

Figure 6. Modified MV network in Lind with marked observable islands [16]

After the grid is found to be observable using the set up algorithm developed in the project and described in [8] state estimation can be initiated. The set up algorithm for state estimation supported by an observability is shown in figure 7.

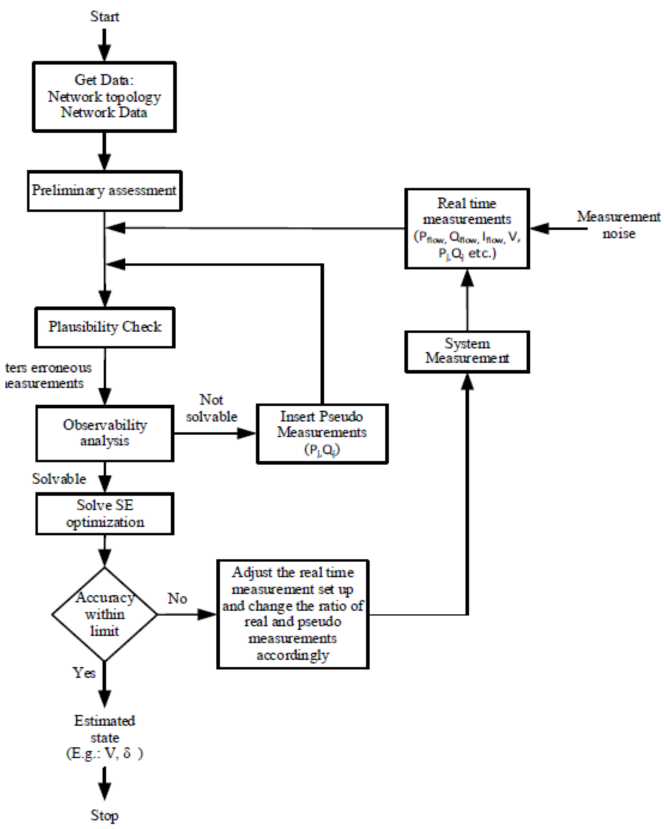


Figure 7. State estimation algorithm including modules for observability check [8]

The detailed equations and mathematical formulations for observability check and state estimation can be found in [3, 8, 10, 11, 12, 13, 14, and 16]. An important method to achieve pseudo measurements are using forecasted values maybe based on smart meter data from previous day, since they so far are not achievable as real-time values. In this project Artificial Neural Networks (ANN) are used as forecast method. In the work correlation, analysis is further carried out to find the most influencing factors (temperature, humidity, costumer class, time of use, holidays etc) which may affect the ANN routine, and these factors are then used with different weights in the ANN. In figure 8. Results with and with use of correlation are shown.

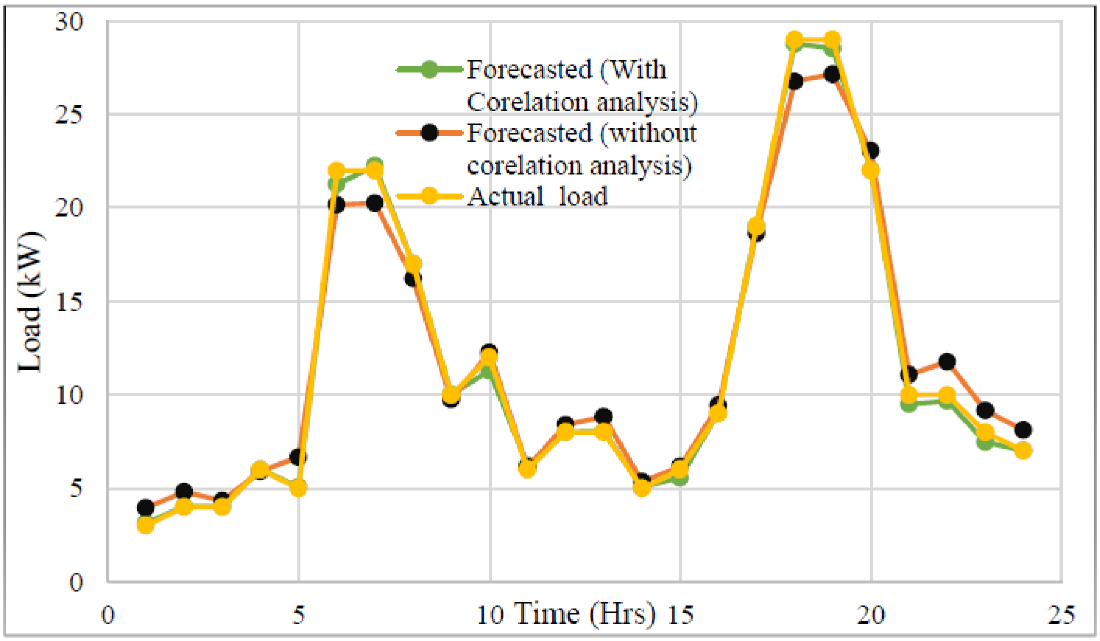


Figure 8. Forecasted values using ANN with or without correlation of different parameters compared to actual value [8]

The state estimation and observability procedure has then been tested by simulation on the grid layout as shown in figure 5. Estimated voltages are shown and compared in figure 9 for 2 different cases: the first one without prioritization of the buses where to place meters (that is not considering the method of dividing the network into islands) and the second where bus prioritization is applied. I the figure it is seen, that in the first case no values are given for bus 13 and 15, which is simply due to the fact, that these nodes are not observable even though real measurements from 30% of the nodes are used, and therefore no value can be estimated. When using the prioritized method only real measurements from 26% of the nodes are used, and the grid is observable and good estimated values are found compared to the actual measurements. The maximum error is 0,96% by applying the proposed method.

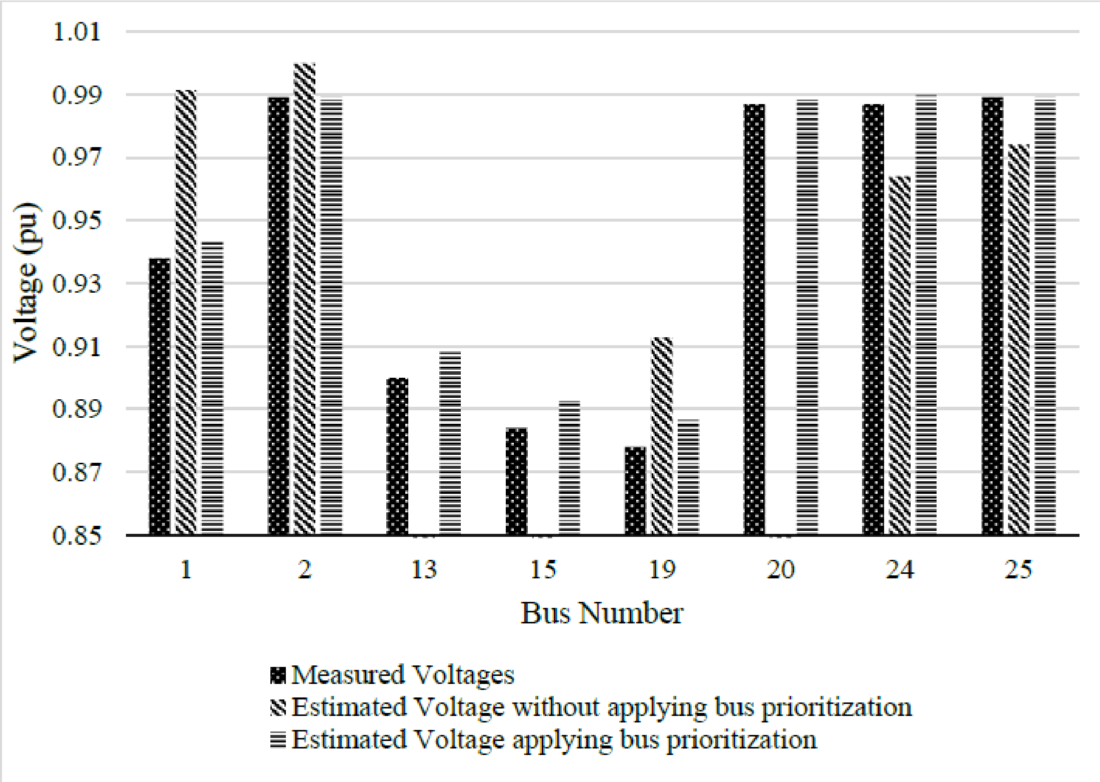


Figure 9. Comparison of estimated states with actual values in two cases [8]

During the last period of the project the observability method and state estimation techniques were verified by actual measurements in the grid. These tests are more detailed described in [6,8]. Tests were performed both at MV level as well as on LV level. For the MV the same grid as shown in figure 6 were used for the verification. There is an existing measurement at the substation level at M1 in the figure. Then observability analysis has identified the best meter allocation to bus 8, 9, 10 17 and 20, but due to practical and economical issues then RTUs provided by ABB were placed at bus 3, 10 and 17. The RTUs measure voltage, current and power injections in all three phases. ABB RTU520 were chosen for the purpose and equipped with KEVA voltage sensors and KECA current sensors. In figure 10 an example of voltage measurements from the three RTus and the SCADA measurement are shown. It is seen that data are missing in certain periods from RTU3. During the demonstration period, this was often seen for especially this RTU.

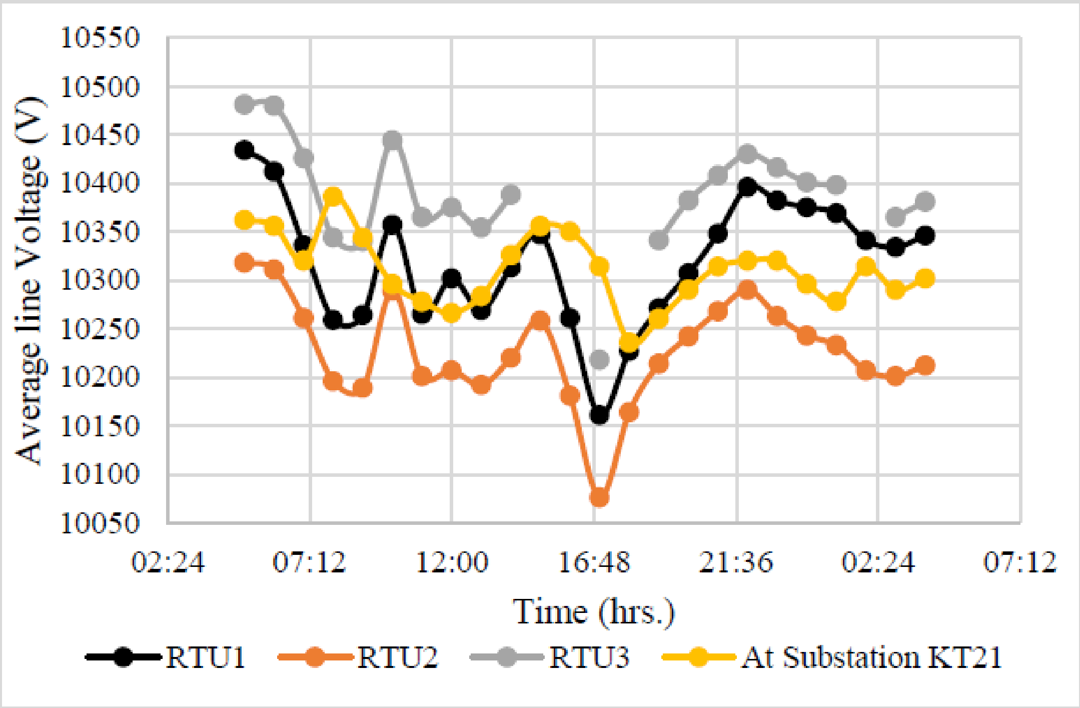


Figure 10. Measured voltage profiles June 1st 2019 [8].

Using the set up state estimation procedure [3] the found error in the state estimation is shown in figure 11. It is seen that the error is higher for the radial where RTU3 is placed in the periods with missing data from RTU3, whereas is does not affect the other radials in the same way (see results for bus 3). This is also expected, since the real-measurements here and the forecasted values at the other radials are still on-going as planned. But what is also seen is that even though real data are missing the error is still quite low due to good forecasted values and the real time measurements from the other radials.

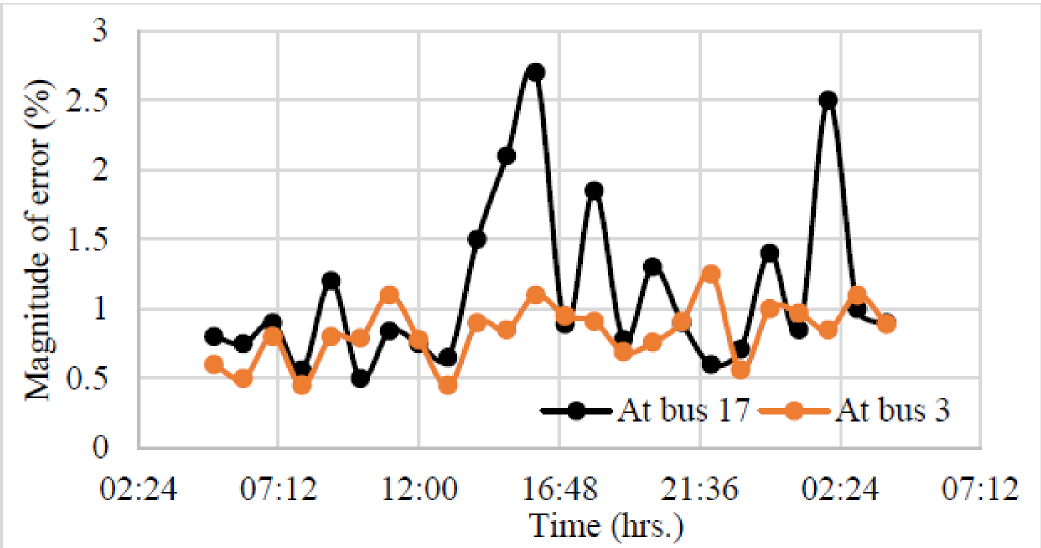


Figure 11. State estimation error at two buses in the grid [8].

For the LV verification a test set up is done for a LV radial as shown in figure 12. Here measurements were done using conventional meters in a cable box at bus 1 and measurements from smart meters from the individual houses connected to the radial were used to give pseudo measurements based on forecasted values based on measurements from previous day.

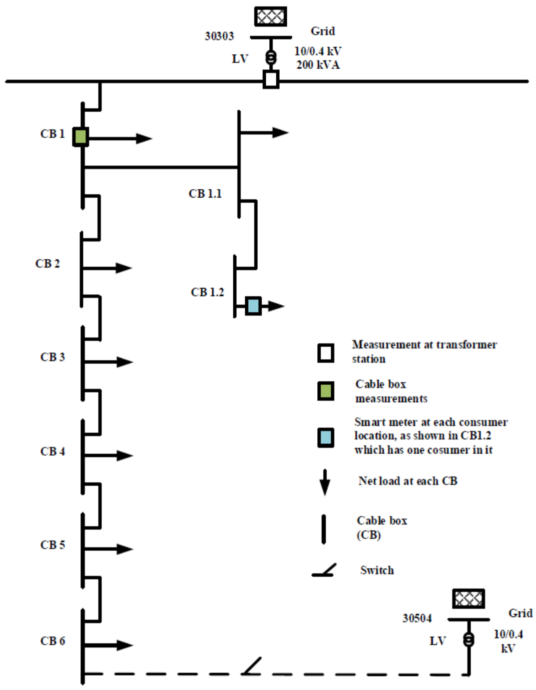


Figure 12. Single line diagram of tested LV radial [8].

Measured power profiles and voltage profiles at CB1 together with state estimation error for the voltage at CB1 is shown in figure 13. For the state estimation two real measurements has been used -voltage and current at CB1- and 8 pseudo measurements using the smart meter consumption data were used. It is seen that the state estimation error is low with a maximum lower than 3%. This is a bit higher than the expected around 1% from the simulations. This can be due to less accuracy in the measurements and not as good forecast as expected, but anyway the error is low and in a useable range.

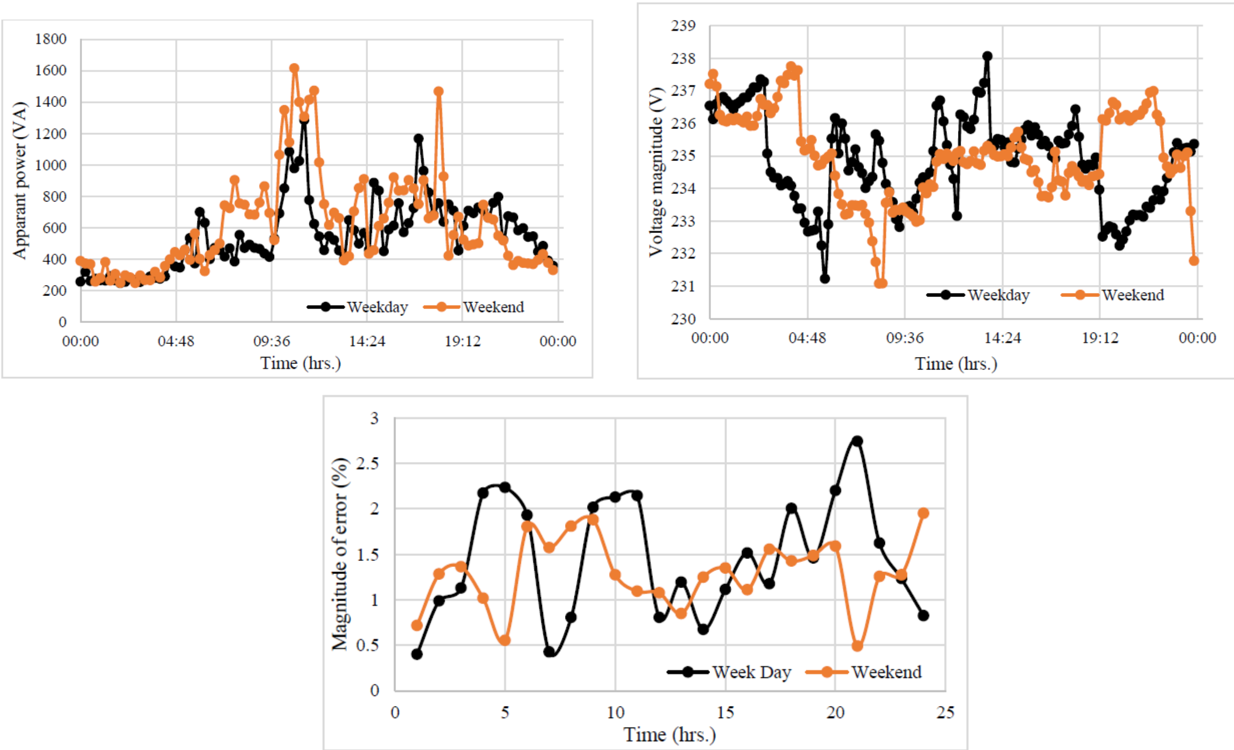


Figure 13. Measurements at CB1 and state estimation error for voltage at CB1 for week 21 2019. Above left Power profile, above right voltage profile, below state estimation error [8].

So in general it is seen that the proposed observability test method and state estimation including ANN forecasted values works well both in simulation and in real environment.

1.5.3 Models for control solutions

This section is primarily based on [2, 5, 9, 17, 18, 19, 20, 22 and 23]. The background for this section is the need for having more control in the distribution grid due to the three main challenges mentioned in section 1.5.1 concerning Grid congestion management, optimization of the operation of the distribution grid and resilient operation of the grid. The objectives of the control are [9]:

- Minimization of the costs of automation and communication infrastructure by novel control methods and effective utilization of existing network assets
- Improved control of the LV and MV distribution networks by integrating advanced monitoring techniques such as dynamic state estimation and generation and load forecasting algorithms

During the project work a hierarchical control framework as shown in figure 5 is set up. In this figure 3 control levels are seen (more information can be found in [2,5,9].

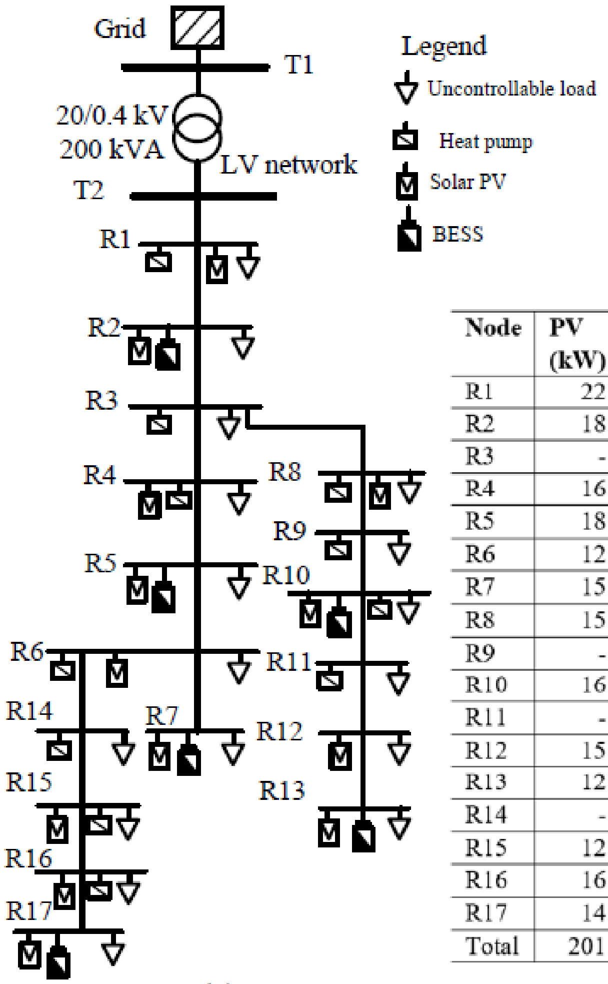
- Level 1 control which is performed at the individual devices in real time, and it is here expected that this can be realized as autonomous voltage controls, where the devices either are on-off controlled or have a droop control (both on reactive and active power) to try to mitigate voltage limit problems at the radials. Different values for the voltage limits for the on-off control or the droops can be set depending on the costumer allocation along the radial. Besides this the level 1 devices also receive set-points from the level 2 control every 10 min, so the autonomous control is only activated in case of under/over voltage problems.

- Level 2 control is an aggregated LV network control which is used for demand response control of the LV distributed energy resources (DER). The set points can come from either a centralized or a distributed control method.
- Level 3 control here the controller is placed at the MV level and it performs a day ahead scheduling calculating the needed flexibility to be achieved from the costumers based on the day ahead market. Additional flexibility can also be initiated via the intra-day market if needed.

Three types of control architectures can be used - centralized control, decentralized control and distributed control. In the project work examples with both centralized control and distributed control are performed. The first method described is a centralized predictive control for LV DERs used to optimize the energy flow and costs in a grid with high penetration of photo voltaic (PV), battery energy storage systems (BESS) and heat-pumps (HP). In the control method an invented linear power flow method is used in the prediction routines, since this power flow method has better calculation of voltage, power and reactive power values compared to other linear power flow methods (more information of this linear power flow method can be found in [9]). An algorithm is set up in [9, 22] to perform the centralized predictive control (also the mathematical formulations can be found in these references):

1. Get the state vectors from the observer blocks.
2. Calculate the linear coefficient matrices and vectors based on the new states
3. Use set up optimization equations to minimize the costs of deviation of aggregated LV network powers form their reference, minimizing the costs of active and reactive power losses and minimizing the cost of power consumption by the DERs
4. From the optimal solution send control set points to the local controllers of the DERs

Simulation studies are done for the network grid shown in figure 14 and simulations are shown in figure 15 for a case without the proposed predictive control algorithm and a case with the algorithm. Comparing the figures in figure 15 it is seen that in the case without the predictive control the BESS starts charging as soon as the sun shines and it is close to its max SOC already by 8 in the morning, resulting in high voltage going beyond the limit of 1.1 pu during noon and also that the transformer is close to its maximum limit of 200 kW in reverse power flow. On the other hand if the predictive control is used, the BESS is not charging as fast, and the control keeps the voltage within the 1.1 pu limit still also obeying maximum transformer loading. More examples can be found in [22].



(a)

Node	PV (kW)	BESS (kVA)	HP (kW)
R1	22	-	10
R2	18	15	-
R3	-	-	8
R4	16	-	5
R5	18	15	-
R6	12	-	7
R7	15	15	-
R8	15	-	8
R9	-	-	6
R10	16	15	7
R11	-	-	8
R12	15	-	-
R13	12	10	-
R14	-	-	8
R15	12	-	-
R16	16	-	10
R17	14	10	-
Total	201	80	77

(b)

Figure 14. LV distribution grid used for simulation of control methods a) schematic diagram b) ratings of PV, BESS and HP [9.22].

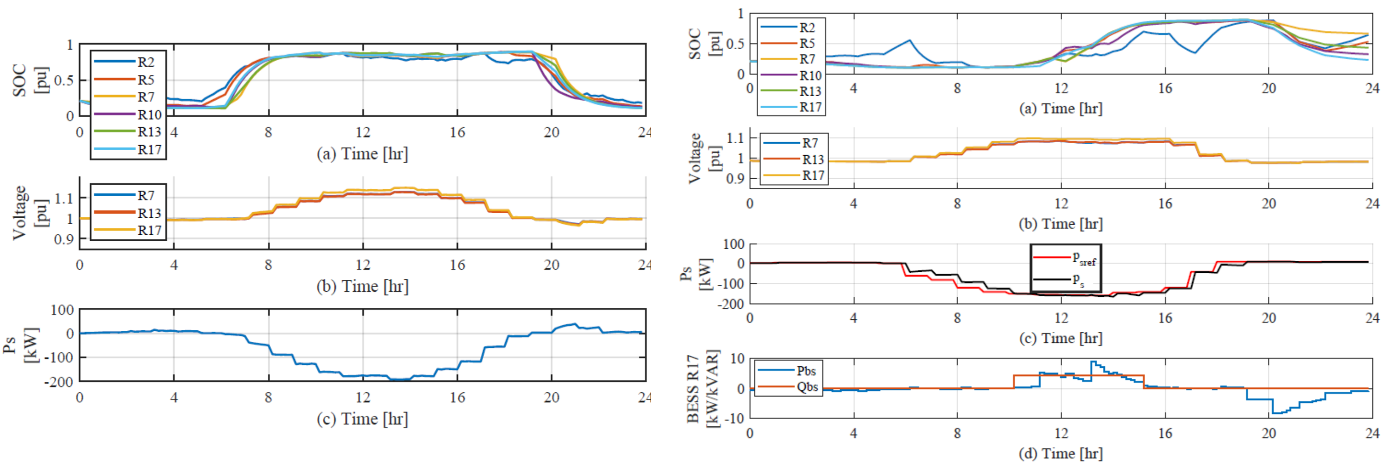


Figure 15. Simulation of centralized control with and without prediction. Left Without prediction on a typical summer day a) SOC of BESS, b) bus voltage as far end nodes of the grid, c) aggregated power flow through the transformer. Right with prediction algorithm a) SOC for BESS, b) bus voltages at far end nodes in the grid, c) aggregated power through the transformer, d) active and reactive power set points computed by the proposed control for BESS at node R17 [9,22].

If the centralized control method are to be evaluated it has some drawbacks [23]:

- Data privacy of costumers can be in unsecure, since all data has to be transferred to the central controller
- It can be difficult to use a centralized controller if the LV distribution grid is large with many costumers, which would normally be the case
- Communication need is high, since states from all devices to be controlled has to be transferred to the central controller

Therefore, it is interesting to look at distributed controllers. They are seen to have advantages due to the following[23]:

- Both DSO, aggregators and costumers can work together for an economical feasible solution
- The computational burden for the DSO/aggregator will be less
- Costumers have better control of their availability, quality of service etc

In [23] two approaches for distributed control of DERs are investigated. The first is based on energy commitment, whereas the second is based on incentive prices. In figure 16 the control schemes for central controller can be compared with the control scheme for the distributed controller using the two different approaches. Compared to the central controller it is seen that the distributed controllers have interactions including feedback between the network controllers and the DERs, for the case with energy commitment the control states are in form of active and reactive power, whereas the control states are the incentive price signal in the incentive based case but still with a feed back in form of active and reactive powers.

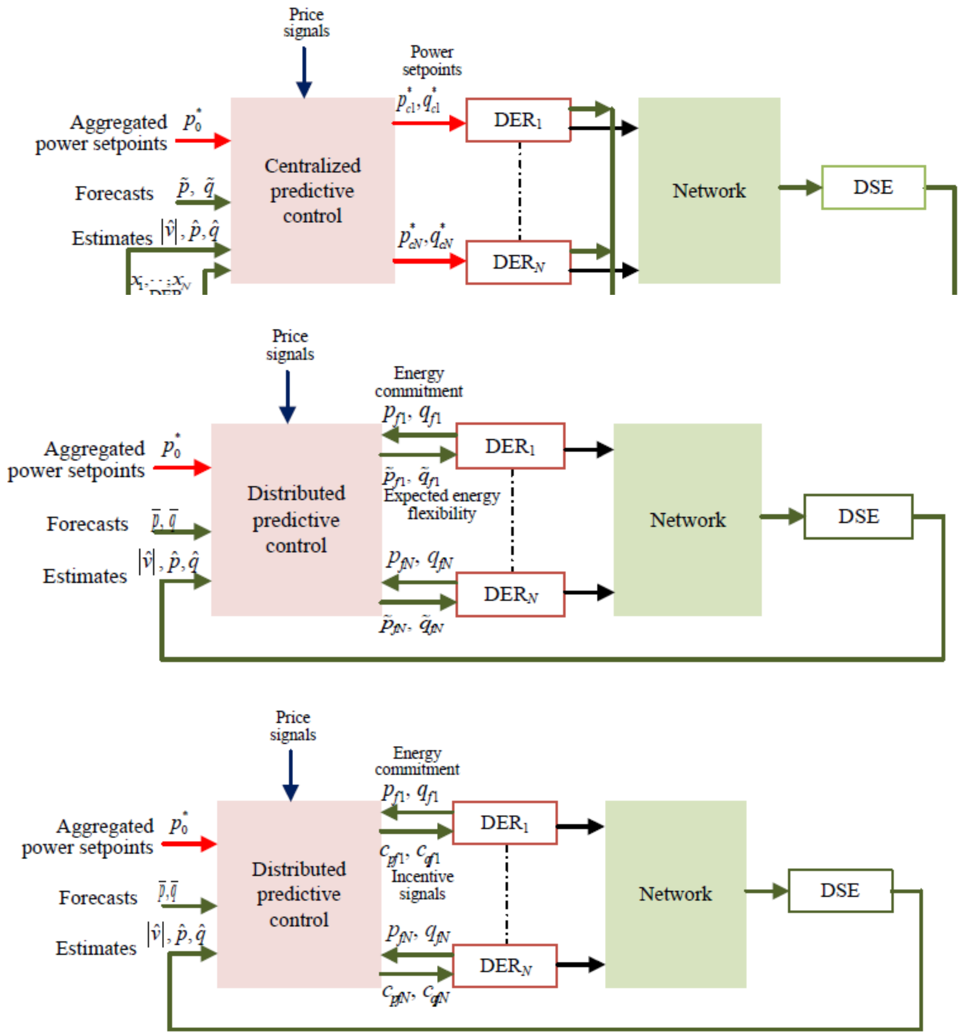


Figure 16. Schematic diagram of upper: centralized control, middle: distributed control based on energy commitment, bottom: distributed control based on incentive prices [23]

The algorithms for the two set up distributed controllers can be found in [23]
To compare the utilization of central controllers to distributed controllers an example of for the grid in figure 14 is made, where the 4 BESS systems are connected to bus 2,4,5 and 7 are connected to maximize the PV power absorption in the grid. A prediction horizon of 4 hours is used. In figure 17 the simulation results of the two methods are shown and it is seen that almost identical results can be achieved.

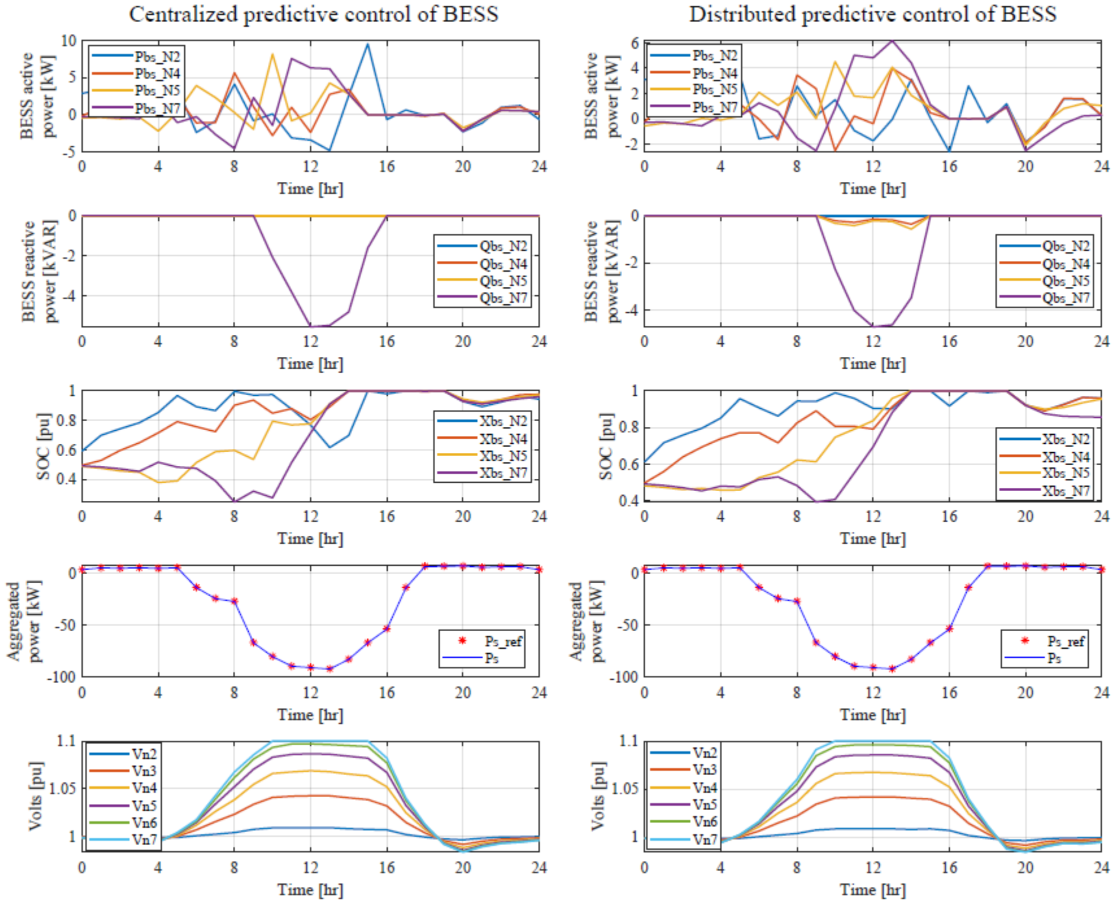


Figure 17. Comparison of centralized and distributed predictive control [9]

One main aspect in relation to the control for congestion management or loss minimization is in the end how to actually get the flexibility from the DERs. In the project four different ideas for flexibility provision is set up [9]:

- Real time flexibility using volt/var control.
    - Here the local controllers on level 1 are using droop controls for the active and reactive power based on measured actual voltage. This control do not need any input from a centralized or distributed controller to work, but is can work in combination with these in the hierarchical control. An example of droop settings are shown in figure 18. In the project, a method for calculating the actual voltage settings depending on node placement along the radial is set up, to ensure, that the droop control actions are more or less equal for all costumers. In this way the costumers at the far out end, who normally will see the highest voltage deviations are not the ones who always have to contribute to the voltage deviation mitigation. A comparison of conventional method where the voltage set points are equal are compared with this new method in figure 19, where it is seen in the

right figure, that all costumers now have the same behavior for reactive power provision.

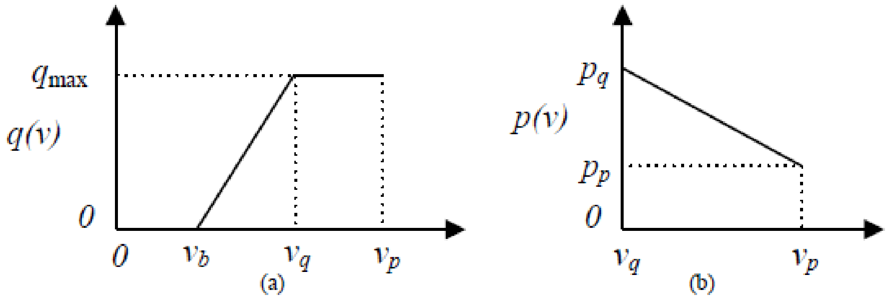


Figure 18 a) volt/var droop control b) active power curtailment droop control [9,19]

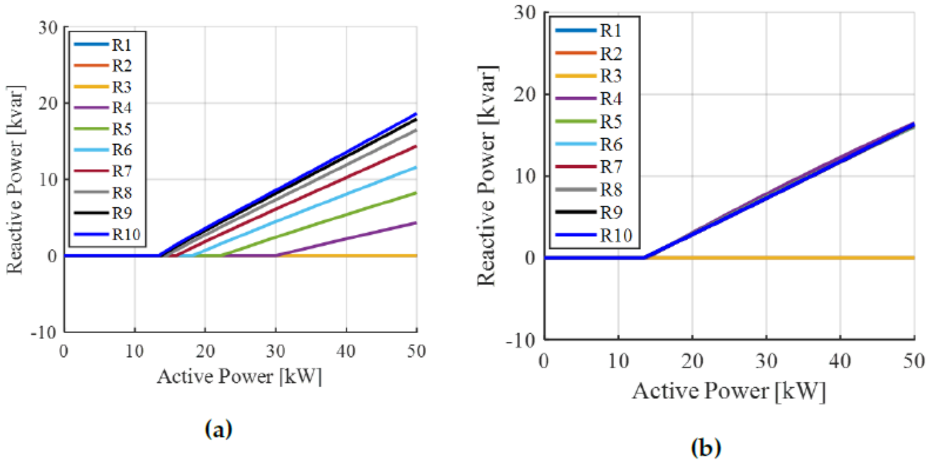


Figure 19 Plot of reactive power provision form a PV inverter using droop control a) conventional method b) proposed method with different voltage settings [9, 19]

- Computation of optimum flexibility
  - An algorithm to avoid network congestion with high integration of pV power is set up in [18]. The flowchart of the algorithm is shown in figure 20 together with simulation results. More details of the simulations are shown in table 1 as well. In the figure and table α is a weighting factor in the proposed optimization algorithm that indicates how much weight demand response should have compared to PV power curtailment. From the simulation cases it is seen, that most PV power is absorbed by the grid when α =1 when also not violating the voltage limit in the grid (max 1.1 pu). It is seen, that demand response is helpful in grid congestion management and for enhancing hosting capacity.

Table 1: Summary of simulations of optimum demand response [9,18]

Case	Peak volt [pu]	PV power peak [kW]	DR power peak [kW]	PV energy absorbed [kWh]
Case 1: No control	1.14	195	0	1226.5
Case 2: PV power curtailment	1.08	112	0	761.5
Case 3: DR with $\alpha = 1$	1.08	185	100	1195.8
Case 4: DR with varying α	1.08	162	50	1050.9

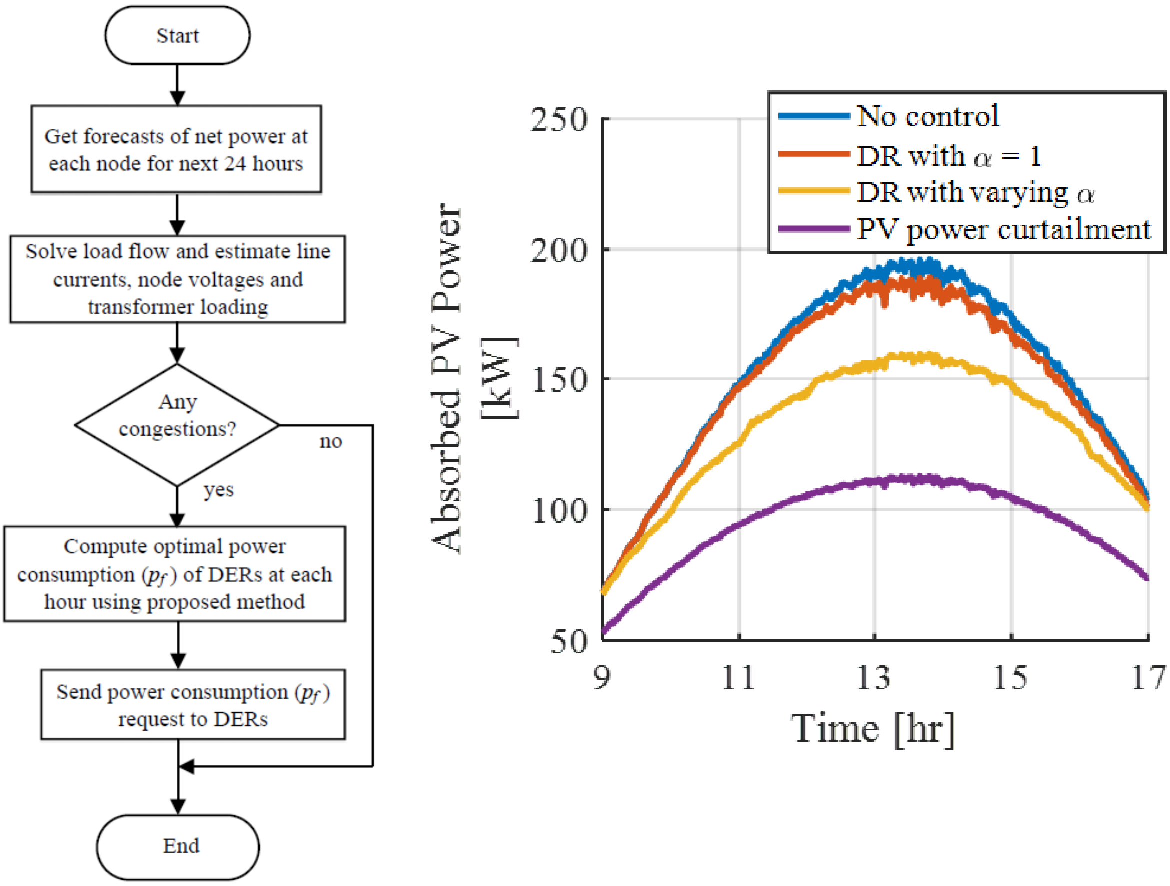


Figure 20. left: Flowchart to manage network congestion in a LV network with optimum flexibility. Right: comparison of absorbed PV power in different simulation cases [9,18]

- Flexibility from BESS for peak shaving
  - Here a BESS placed in the far out end of a node is used for peak power shaving so the BESS are charged during high PV power feed in and discharged at peak demand periods. In the BESS control optimization both costs for power regulation and power loss. The control to compute the active and reactive power set points of the BESS at every 10 min time step is based on a quadratic programming problem and details are given in [20]. Results for the method is shown in table 2 and in figure 21. From the results when using the control the voltage are kept within limit (below 1.1 pu) in case 3 the peak power reduction is

less than in case 2, but the method might be applied to reduce battery degradation due to often variations of SOC.

Table 2: Summary of simulation results from proposed BESS control [20]

Case	Maximum voltage [pu]	Peak power reduction [%]	Net energy loss [kWh]
Case 1: Without BESS and no control	1.107	0	85.54 (6.30%)
Case 2: Peak shaving and minimum loss	1.086	20	78.52 (5.98%)
Case 3: Peak shaving, minimum loss and minimum variation in SOC	1.092	15	81.49 (6.08%)

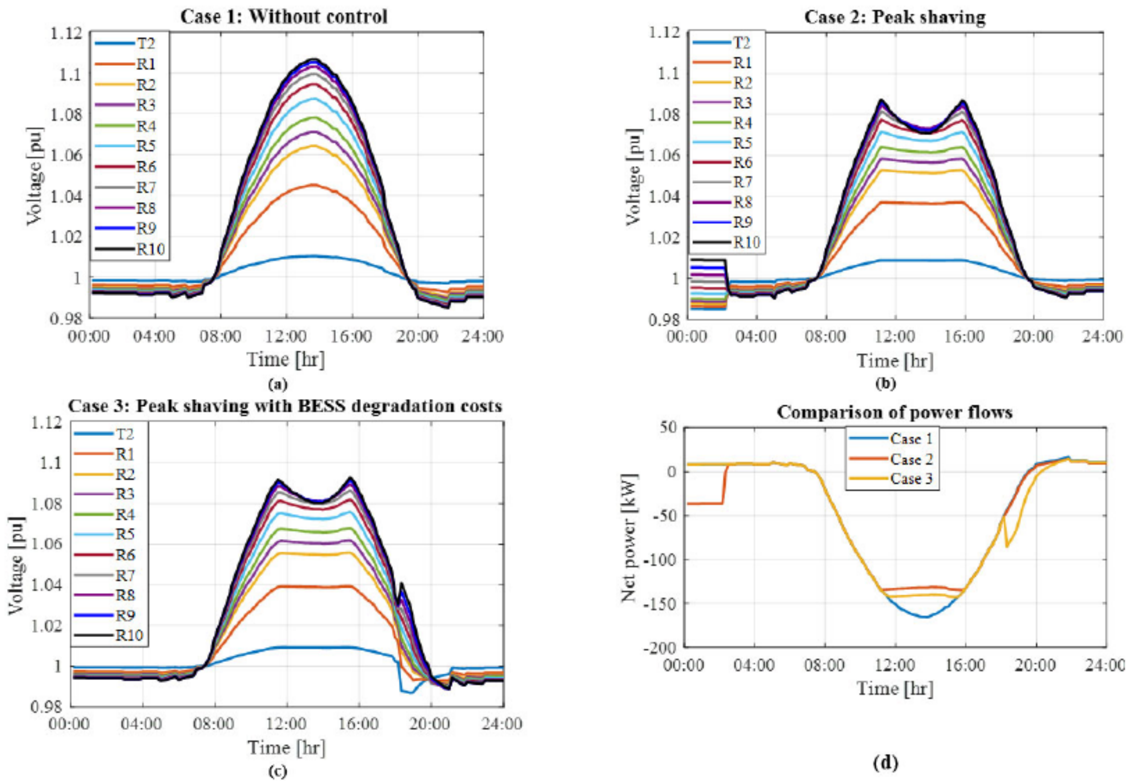


Figure 21: Simulation results for case with flexibility from BESS a) Without BESS and control b) with BESS control but without routine to minimize battery degradation c) BESS control with battery degradation routine d) aggregated power flow at secondary side of LV transformer in the three cases [20].

- Flexibility for network congestion management
  - An algorithm for congestion management planning (CMP) and one for congestions management operation (CMO) are set up during the project. Both are based on a predictive control algorithm which uses second-order cone programming (SOCP). The algorithm uses the state estimation routines and forecasting methods explained in sec-

tion 1.5.2 and are also expected to have input from the electricity market. The planning algorithm estimates the planned flexibility to be achieved for the DSO for the next day based on day ahead forecast of aggregated generation and loads. Then the algorithm is run to ensure that network grid violations does not occur and required flexibility is calculated. Then the final schedule is communicated to the individual DERs. An example for the branch loading in the grid with and without demand control is shown in figure 22. It is seen that it is always possible to minimize the peak load, and also that the congested branch M6-M7 is relived from overload. Regarding the algorithm for operation congestion management, this algorithm works with a time step of 10 min and can be used in relation to the balancing market. It also calculates aggregated set points for the DERs based on state estimation inputs. The set points are following communicated to the individual DER controllers. Simulation results from this control is seen in figure 23. From this figure it is clear, that the under voltage situation which occurred without control can be mitigated using the set up demand response method. More information of both methods can be found in [14]

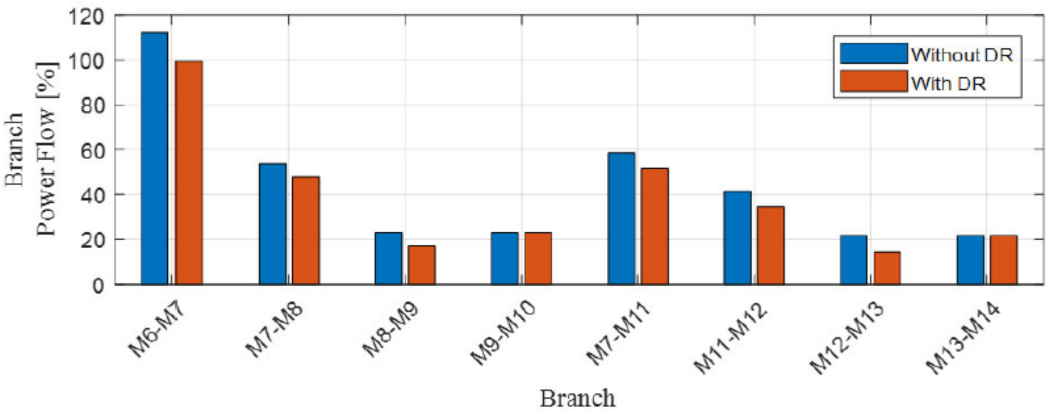


Figure 22. Branch loading with and without demand response flexibility procured from day-ahead market [14]

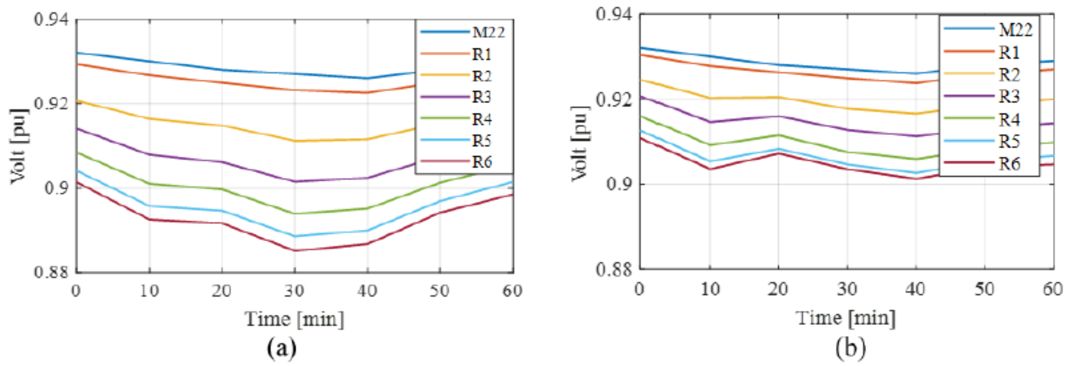


Figure 23. Node voltages from a LV grid a) without used algorithm for operation congestion management, b) with used algorithm for operation congestion management [14]

From this section it is seen that a hierarchical control is beneficial at different levels, and that the control can be done both as a centralized control if the grid is of limited size or as a distribution control if the number of costumers are high. The advanced algorithms and mathematical formulations can be further explored in [2, 5, 9, 17, 18, 19, 20, 22 and 23].

1.5.4 Network reconfiguration and protection

In the project also network re-configuration and adaptive protection issues has been considered. Both simulations and test in laboratory to verify the set up methods in this area has been performed. In [9] the need and used of network reconfiguration are based on:

- Network power loss reduction – because of the high penetration of DERs the loading of the radials might shift and cause more network power losses, which might be decreased if network reconfiguration is used
- Load balancing – depending on the site for DERS compared to loads the radials might be congested at time with high generation and low loads or visa versa. By rerouting the power flow the loading of each branch might be minimized.

The set up network reconfiguration scheme is based on a mixed-integer linear programming which is detailed explained in [9 chapter 2]. As a case study to verify the method the network grid shown in figure 24 are used. This network contains 5 switches and DERs in form of PV and wind-turbines. The proposed network configuration method is first compared with the normal load flow model using Newton Raphson method for a fixed configuration of the grid. In this the status of the switches are S(0,1)=closed, S (4,25)=open, S(10,14)=open, S(7,11)=closed and S(14,22)=open. For this situation it is found that the error between values of total active power losses, total reactive power losses and the error of the voltages are all well below 1% compared to when calculated by the Newton Raphson method which are expected to calculate very precisely. This indicates that the set up method does the calculation very precisely even though it is a faster an optimized method. Now this method is used to find the best configuration to minimize the power losses in the grid and the found set up is as follows: S(0,1)=closed, S (4,25)=open, S(10,14)=open, S(7,11)=open and S(14,22)=closed. Comparison of the two cases (the original set up, and the new set up where S(7,11) and S(14,22) change status) are shown in table 3, from which it is seen that the reconfiguration reduces the losses from 6.75% to 5.68%. The method can easily be extended to larger network grid, gaining more benefits.

Table 3. Simulation results from optimized network re-configuration [8].

Case	Active power at MV substation (P_s) [MW]	Reactive power at MV substation (Q_s) [MVAR]	Total active power losses (P_l) [kW]
Base case before reconfiguration	12.55	6.12	847.25
After reconfiguration using MILP	12.42	6.02	706.18

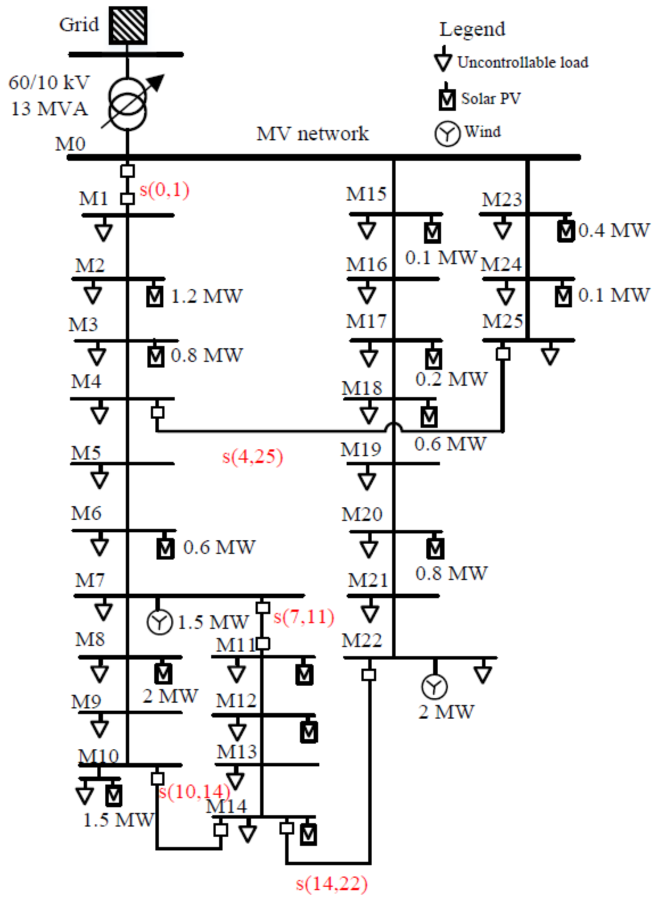


Figure 24. MV distribution grid used for examples with network re-configuration [9]

In the laboratory also test with network reconfiguration is performed using a RTDS® simulator supplied by RTDS Technologies. The test case is performed on the network grid example shown in figure 25. In this case however, the network reconfiguration is done due to a fault in the grid. In the simulation it is assumed that the breaker CB1 is switched off due to mai-operation of relay REL12 or due to an event outside the MV feeder. In this case DG2 might provide power to the grid for a short period but will be disconnected to prevent island operation, why this radial where DG2 is placed will be out of power. However if CB49 is then switched, there will be a connection to the isolated part of the grid and the power supply is re-established. Simulation of this situation using the RTDS system is shown in figure 26, where it is seen, that first the system is disconnected, but after a short while the voltage and current returns to normal operation (upper and lower curves).

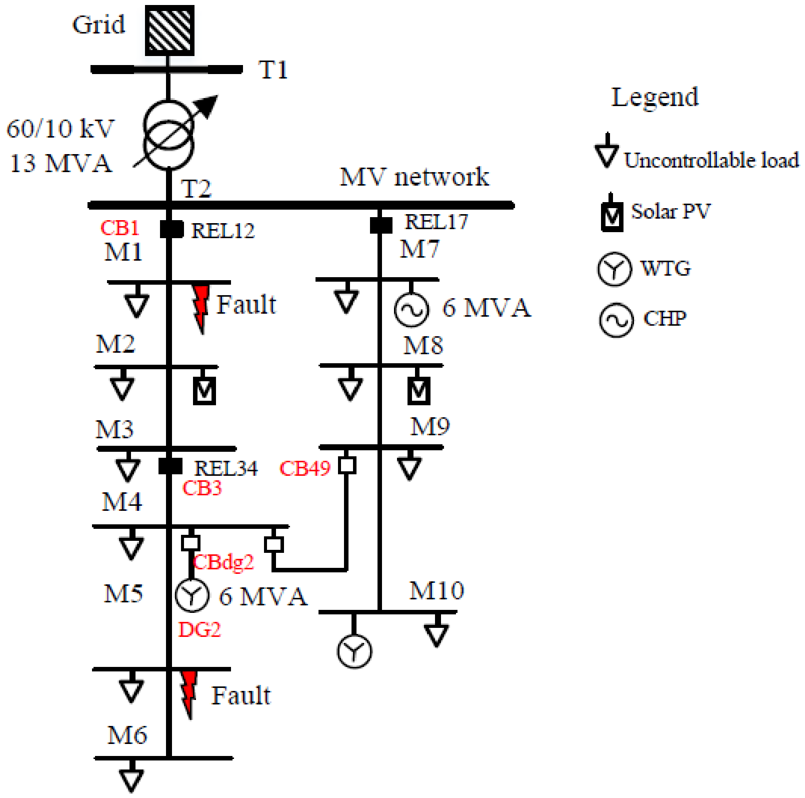


Figure 25. Simplified schematic diagram of 60/10 MV network grid [6]

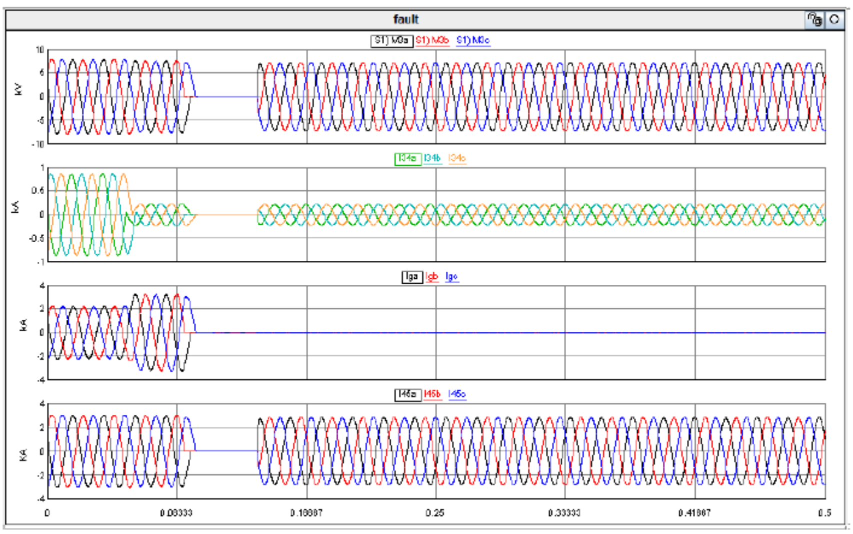


Figure 26 Plot of currents and voltage after trip of CB1 with re-configuration [6].

Next tests are performed with adaptive protection showing examples with use of adaptive values for preventing protection blinding and false tripping. The risk of protection blinding are due to penetration of high power distributed generation (DG) in the grid, which might reduce the fault current in a radial where the DG is placed downstream the radial seen from the protection relay point of view, see figure 27. In similar way false tripping might occur if a fault is occurring is an adjacent radial compared to a radial where the DG is placed. In this situation the DG will contribute to the fault, and the relay in the radial with the DG might see a too high fault current and trip, even though the fault is not present in this radial. This situation is also shown in figure 27.

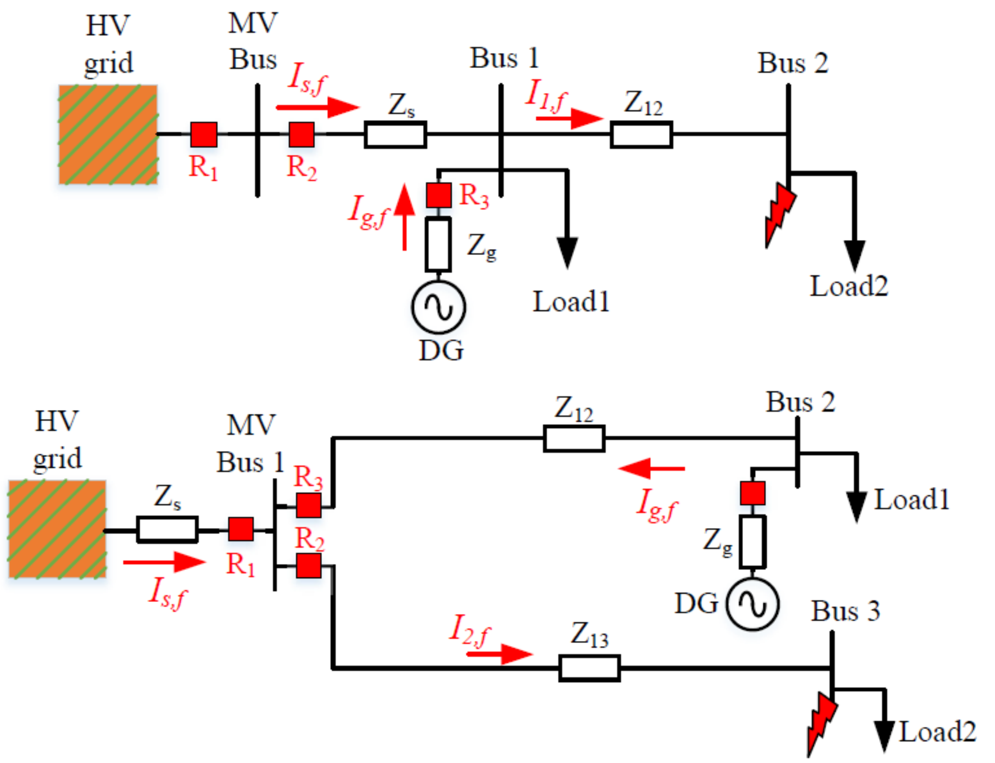


Figure 27 Schematic MV network to explain upper: protection blinding, lower: false tripping [9]

Test with protection blinding and false tripping are done both with simulations in Matlab and DigSilent Powerfactory software and in the laboratory using the RTDS® simulator. Adaptive protection is used, where the settings of the relays are changed according to the presence of a DG or not. Also test with hardware in the loop (HIL) are performed where a ABB overcurrent relay REF615 I used for verifying simulations with protection blinding. Three cases are performed:

- Case 1. Without any DG connected to bus M4 in figure 24.
- Case 2: with DG connected at bus M4 and normal relay settings (as if there were no DG)
- Case 3: with DG connected to bus M4 and adaptive relay setting (setting according to actual size of DG)

In table 4 results from the tests with HIL is shown. It is clear that the actual response time in case 2 is longer than expected, since the current is small compared to the settings of the relay, who does not expect any contribution from the DG. This might cause problems that other relays then operate, if not proper coordinated. However, if adaptive protection is used as in case 3, the actual operation time is like in the first case, and the risk of protection blinding is avoided.

Table 4 Results from HIL test in laboratory with protection blinding [6].

Cases	Actual I_f [kA]	I_f in the relay [sec.A]	I_p	TMS	Expected t_d [s]	Actual t_d [s]
Case 1	6.02	1.53	1.4	0.06	0.3	0.33
Case 2	4.95	1.48	1.4	0.06	0.3	0.42
Case 3	4.95	1.48	1.25	0.05	0.3	0.32

It is seen from this section that use of network reconfiguration can optimize the use of the network grid. In normal operation network reconfiguration can be used to lower power losses and reduce power loading of the lines. In fault conditions the reconfiguration can be used to reconnect area with have an outage, so the outage time can be limited.

Regarding protection blinding and false tripping adaptive settings of the relay parameters can prevent these situations to ensure a more reliable protection of the future grid. More information related to this section can be found in [4, 6 and 9].

1.5.5 Interfaces between DSO and TSO for system security and reliability

The final work in the project relates to DSO/TSO interaction and the main references to this section is related to [7, 8, 9, 15, and 21]. First stakeholders interaction as of today are analysed and ideas for how it should look like in the future are set up, if there should be better possibilities for provision of ancillary services to the TSO level from the DSO level. Figure 28 pictures stakeholder´s interaction in the traditional set up and the needs in the emerging scenario. It is seen how aggregators will be involved together with the balance responsible actors to provide flexibility from costumers, and how decentralised power plants are taken into account via also the balancing responsible to act on the electricity market.

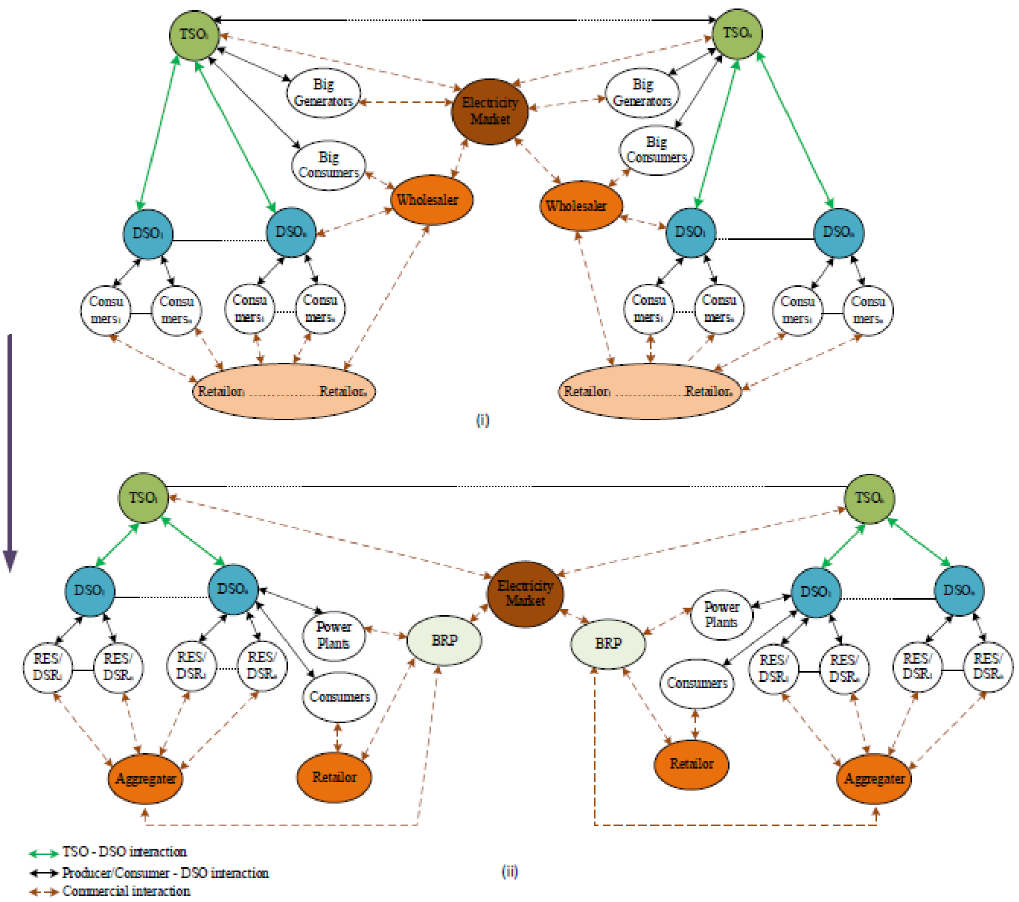


Figure 28. Stakeholders interaction in (i) traditional and (ii) emerging scenario [8, 15]

Some of specific grid operation challenges identified for the future electricity system can be seen in table 5 below. Issues of concern are fluctuating power generation from renewables, communication needed, new stakeholders and new markets.

Table 5. General grid operation challenges that concern TSO-DSO interface [15]

Grid operation challenges	Description	Concern in TSO-DSO interface
Data security and handling	• Huge data will be available due to smart meters, RTUs/PMUs, load/generation forecasting of distributed consumers and producers etc.	i. Who will take ownership of these data? ii. How individual's privacy can be guaranteed? iii. Are there any guidelines for data exchange between TSO and DSO? iv. How to identify which data are beneficial for each other (TSO and DSO)?
Operation in new market setup	• Market should be fully liberalized to host increasing DG/RES/flexible loads at distribution grid. Due to this, new participants like aggregators, prosumers, BRPs, retailors are emerging in the new scenario.	i. What is the best market structure in new scenario? Is the market fully liberalized? ii. If yes, how each market participants are interacting with each other and how they are linked with TSO and DSO? iii. What commercial information is exchanged between TSO and DSO? iv. Is both transmission and distribution capacity limitation considered between market zones?
Congestion of TSO-DSO interfacing transformer and transmission line respectively	• Interfacing transformer is more likely to be overloaded due to increasing DG/RES/loads at distribution grid. If this transformer is not owned by DSO, they have to communicate to TSO in this situation. • Overloading of transmission line, which can happen due to overloading of many interfacing transformer and TSO's own customers.	i. Who owns this transformer? TSO or DSO ii. If owned by TSO, and in case of congestion, how communication happens? Manually by phone or automatically? Does TSO sends signals directly to feeders for disconnection? iii. Does TSO communicate to the DSO before disconnecting interfacing transformer to avoid transmission line congestion? iv. Is possible congestion avoided in planning phase and later it never happens? Example: applying n-1 criteria? v. Is TSO-DSO interfacing area fully observable using network state estimation and forecasting of loads/generations? vi. Are there any control measures at TSO-DSO interfacing area to utilize the flexibility available there?
Challenges in Power balancing	Difficulties in balancing the grid due to fast fluctuating generation and consumption.	i. Are generators and loads from DSO network participating in balancing market? ii. Is DSO involved in prequalification processes related to ancillary service from the loads and generation at distribution network? iii. Real time balancing platform exists or not? iv. Are smart meter data measured by DSO used for flexibility assessment and communicated to TSO? v. There is possibility for TSO to balance its grid by having bilateral contract for flexibility from generator or loads. Is DSO involved somewhere or not?
Voltage support on both transmission and distribution network	Using flexibility on distribution grid and tap setting of interfacing transformer both DSO and TSO can support the voltage at each other's network respectively.	i. Voltage control on Transmission network: Does DSO support voltage at TSO lines by activating flexibility on distribution grid. If yes, how it is communicated? ii. Voltage control on Distribution network: Does DSO control voltage level with TSO-DSO transformer tap setting at distribution grid? If yes, and transformer is owned by TSO how communication happen?
Interoperability Challenges for coordinated protection	In case of faults in transmission grid, alarms can be seen in the distribution system and even force to trip the distribution grid component and vice versa.	i. Are there any interaction between DSO and TSO for coordinated protection? ii. If yes, are there real time data exchange for this? iii. Do DSO's protection system receive any settings from TSO or vice versa iv. Are there any guidelines or protection policy available and implemented as of today for TSO-DSO data exchange in particular area ?
Challenges during Islanding at TSO-DSO interfacing	Islanding: Technically zero power flow from TSO-DSO interfacing transformer; detection of such situation,	i. Are there regular exercise with participation from both DSO and TSO? ii. If yes, what type of data are exchanged (human interaction or automatic?) for island detection, re-synchronization and balancing

area, re-synchronization and black start	re-synchronization and balancing after that.	

Also the current practice for DSO-TSO interaction in Denmark is identified as shown in table 6.

Table 6. Summary of current TSO-DSO interactions in Denmark [15]

TSO-DSO Interaction for	Current practice in Danish case
Data Handling	• TSO operates the Data hub and owns it in accordance with the applicable legislation under Danish act under the processing of personal data. • Any grid company/DSO can access the data under certain terms and condition and are obliged with market regulations.
Operation in new market structure	• Denmark is a participating in Nord pool market. Only transmission capacity limitations are considered in the market settlement. • Only TSO is involved in market clearing process and get the hourly operating schedule from the market. • New stakeholders like BRPs, aggregators and retailors are emerging mostly at DSO level.
Congestion of TSO-DSO interfacing transformer	• Interfacing transformer is 150/60 kV and is owned by TSO but 60 kV circuit breaker at this transformer station is controlled by DSO. In case of congestion, communication (regarding frequency) are automatic. • Mostly n-1 contingency analysis is carried out in planning phase.
Transmission line congestion	• TSO communicates DSO before disconnecting interface with DSO. • Although some level of analysis is carried out during planning phase but still transmission lines are overloaded in many situation.
Grid balancing	• Generators and loads in DSO network are participating in balancing market and are controlled by TSO. • DSO is not involved in prequalification, TSO takes care of this. • Consumer flexibility is not assessed by real metering data measured by DSO. It is done by data hub. • DSO is not involved in the bilateral contract between TSO and generators or loads at distribution grid. TSO is balancing its grid based on this contract.
Voltage support on both TSO-DSO side	• DSO helps TSO for voltage support by reducing its load at the step of 10%. • TSO helps DSO for voltage support by changing the taps in the interfacing transformer. It is communicated via SCADA system of TSO.
Interoperability for real time control and coordinated protection	• Some level of communication and real time data exchange is carried out via SCADA. • Communication standards and protocols for this data exchange are available.
During islanding, re-synchronization and black start	• Regular exercise to avoid possible hazard due to islanding have been carried out by TSO with the participation of DSO.

Finally, based on the set up challenges and the expectation to stakeholders involved in the future scenario a table for new dimensions of the TSO-DSO interface is set up. This is split up into non-technical and technical clusters.

Table 7. Description of new dimensions of TSO-DSO interface [15]

Cluster	Dimension of TSO-DSO interface	Descriptions	Remark
	Data handling	• More data will be required in the emerging scenario for enhanced operation that enables consumers participation (i.e. entry of aggregators and DSR activities), improve network observability and real time	• Collection of real time data from each small scale RES/DG/DSR for TSO and DSO will be difficult or more costly. • Framework to identify required data type, its quality and ownership has to be put in place by TSO and DSO jointly. It should also guarantee the security and privacy of data. It will simplify the processing of huge data and help to maintain

Non-technical		control. • These data can be available from smart meters and new stake-holders in the market (Aggregators, BRP etc.)	fair market competition.
	Market framework	• In the traditional mar-ket set up TSOs are not involved in retail mar-ket. In the new set up TSO's involvement in retail market is neces-sary because prosumers or DSR entity at DSO network are participat-ing in market and are also providing system services like balancing, frequency response etc. which are needed by TSO. • Therefore, clear and defined roles and re-sponsibility of TSO and DSO are now important whatever the market framework be.	Based on individual stakeholders' coordination pattern some conceptual market framework that can be used in emerging scenarios are identified as: • ***Improved traditional framework***: One TSO operated ancillary service market for resources available at both TSO and DSO network. Here, DSO is not involved in market settlement process and its con-straints are not considered too. • ***Separate market framework:*** DSO operates separate market for resources connected to its own network and can of-fer the aggregated bids to TSO operated market only after solving the local grid constraints at DSO level. • ***Shared framework for balancing***: TSO and DSO share the responsibility of net-work balancing. However, they balance their respective network using own re-sources only in their respective market where their respective constraints are considered. • ***One flexibility market framework:*** One market for all resources in the sys-tem (both TSO and DSO). Operation could be single or integration of TSO op-erated market and DSO operated market in real time. Both DSO and TSO constra-ints are considered. • ***Combined flexibility market frame-work:*** Single common flexibility market but operated by separate independent operator (not TSO and DSO). Resources allocation based on price. DSO constra-ints are considered.
Technical	Network planning	• Traditional planning approach may not ena-ble the potential of prosumers/DSR/RES connected to distribu-tion grid for system services (congestion management, voltage support etc.). Provision of only grid connection facility for DGs at DSO network may not be sufficient in future.	• Integrated planning approach where TSO and DSO should interact from planning phase is necessary. • DSO's knowledge in local and regional level demand and generation harnessing will be crucial information for system ex-pansion planning in new scenario, which demand regular interaction and exchange of information between TSO and DSO for system planning purpose.
	System operation and control	• Increasing RE based generation at DSO net-work replacing conven-tional generators at TSO network. • Even in new scenario, TSO will have main re-sponsibility for balanc-ing, frequency control and system restoration whereas DSO will man-age its own network congestion and voltage management.	• To utilize the DG/DSR's capability for ancillary service, proper operational setup is required to minimize the scarcity of system service at TSO network. • Enhanced observability of DG/DSR con-nected to the DSO operated network and defined observability reach of both TSO and DSO with sufficient overlap as shown in Fig. 4 is required. • It will improve the security of supply, minimize the impact of forecast error also help to limit the reserve margin due to uncertainty.

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As seen from Table 7 a lot of new issues has to be dealt with which have lead to the recommandations as given in table 8.

Table 8. Recommendation for TSO-DSO interaction in smart grid operation [15]

S.N.	Interaction for	Recommended strategy for future
1	Data handling	• Security of data (e.g.: costumer consumption history data recorded via smart meter) can be guaranteed by independent Data hub center under the owner ship of public entities not within TSO or DSO. • DSO can share the estimated/measured network status from the selected interfacing area to TSO and vice versa.
2	Market strategy	• Since distribution grid is becoming more active, considering distribution system limitation too in market settlement will increase the system operation reliability. • In addition, DSO involvement in market clearing process can help DSO to balance its network locally and reduces the stress on TSO. For this, either TSO should share the operation schedule received from market to DSO or market should also have direct communication with DSO. • More liberalized local market is another possibility where power can be utilized locally in DSO responsible area by operating DSO operated local market. In this case, resources can be traded locally and they can contact upper market (regional market) only for excess load or excess generation or for balancing purpose.
3	Congestion management (interfacing transformer and transmission line)	• More relevant and detail data exchange within the common observability area that will increase the flexibility use and reduce the transformer loading. • DSO can send the flexibility information collected from aggregator to TSO. • TSO can analyse and use flexibility available at distribution network to minimize transmission line congestion. Prioritization technique can be used to select the flexibility available in transmission and distribution network respectively.
4	Network balancing	• DSO can take part in grid balancing via aggregator • DSO can take the role of local network balancing • Overlapping should be avoided between flexibility trading signals (commercial signals) with network operation signals using flexibility otherwise it will miss lead the operation.
5	Voltage support	• Reactive power from DG can be used for TSO voltage support in a coordinated manner. • Existing capacitor banks at DSO network can be used for TSO voltage support. • TSO-DSO can agree on specific set point for reactive power/power factor/voltage at interfacing point.
6	Coordination in real time control and protection	• Exchange the measured/estimated network data for protection for quick localization of fault.
7	Islanding detection and black start	• Share the DG/RES production forecasted so that TSO can use these units for grid restoration

In relation to provision of ancillary service from the DSO to the TSO a figure of the present and future expected interactions is shown in figure 29. In the future both active and reactive power set points are expected, and it can be seen that the DSO is involved in activation of the DGs together with the DSO.

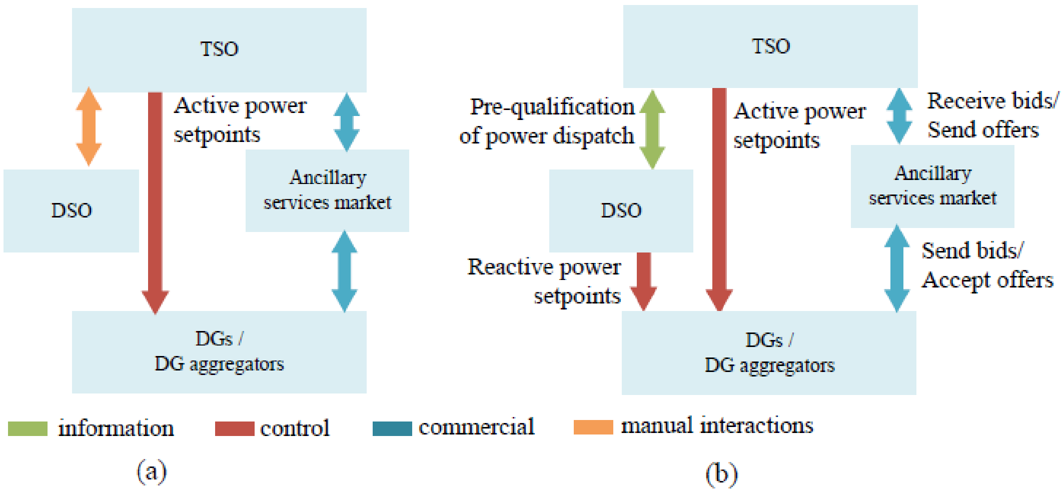

Figure 29. Interaction of TSO abd DSO for secondary frequency regulation in a9 present scenario and b) with proposed advanced TSO-DSO interface (ATDi) [21].

Based on this set up an ATDi control set up which can be used for the Danish DK1 where the DSO helps in providing automatic fast frequency reserve (aFFR) area is shown in figure 30. In this control a proposed optimal power flow programming (OPF_Q) using semidefinite programming (SDP) is used to find the minimum amount of reactive power from the DERs taking network constraints and DER constraints at DSO level into account. All the mathematical formulation of this OPF_Q and SDP can be found in [21]. The flowchart for the control is shown in figure 31.

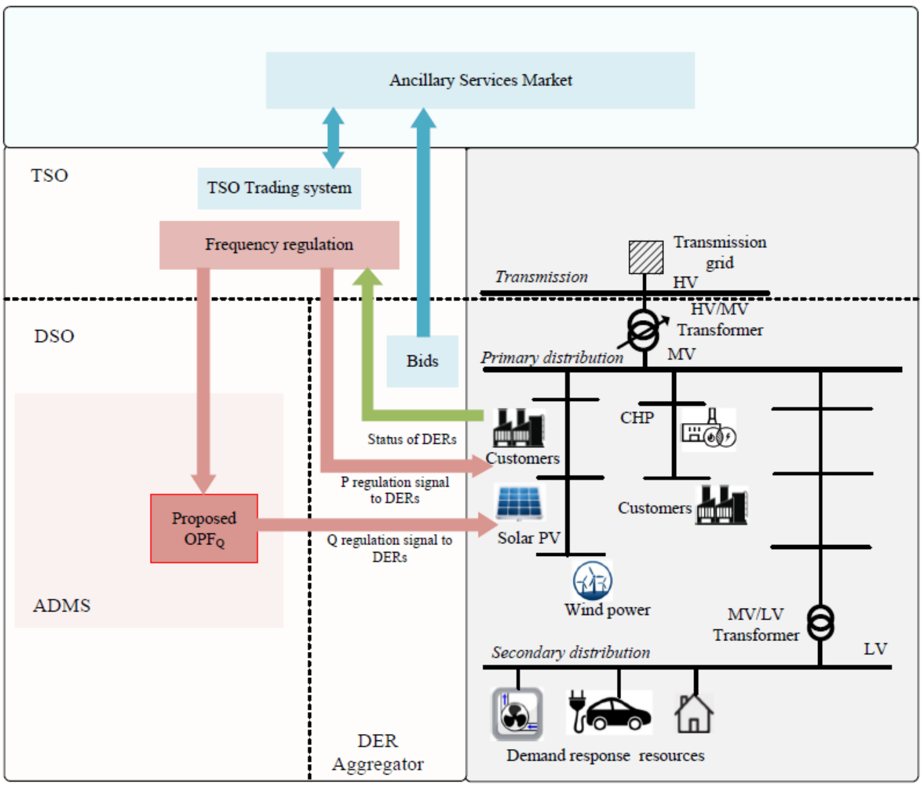

Figure 30. Schematic diagram of proposed ATDi which can be used for DK1 area in Denmark [21]

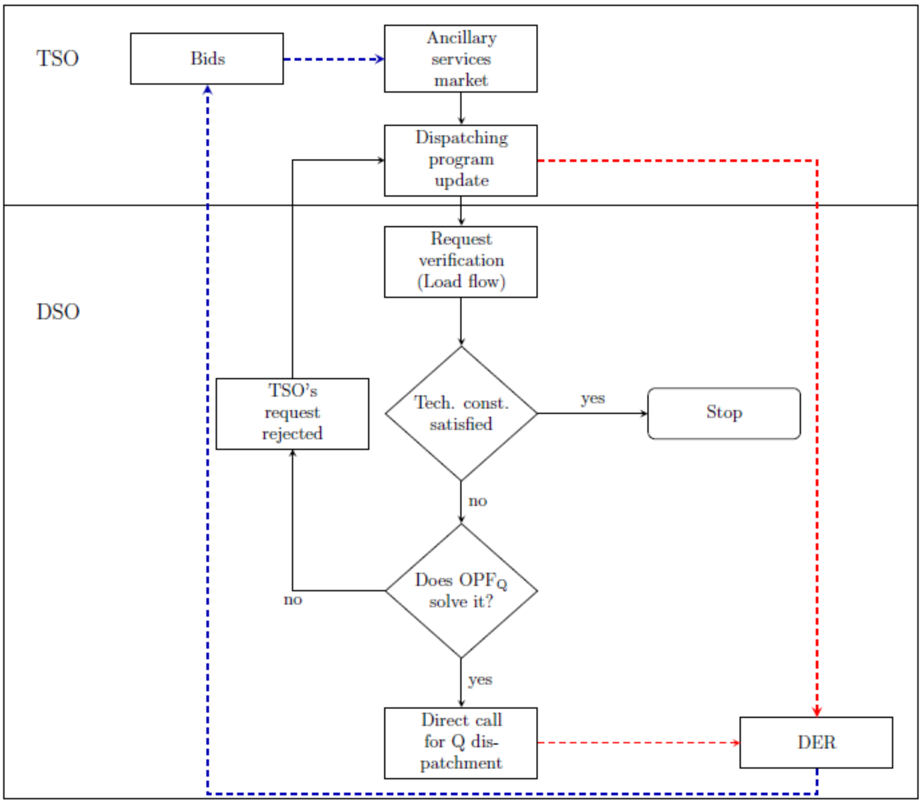

Figure 31. Flowchart for involvement of DSO in provision of aFFR [21]

The method is shown for a small part of a DSO grid in the area of Støvring in Denmark as shown in figure 32. Two cases are shown. The first is a case where hypothetical power response requests from the TSO to the DERs as shown in figure 33a are used. The voltage at all MV nodes in this case is shown in figure 33b, and it is seen that the transformer voltage is above limit since the DSO is not aware of the request from the TSO to the DERs, so no reactive power provision are used.
In the second case, it is assumed that the TSO inform the DSO about the actual active power request. Then reactive power set-points from the DERs are found by the DSO by running the OPF_Q. The simulation results from this case in seen in figure 34, where it is seen, that now the voltage constraints are within limit, and the figure also shows the reactive power provision form the CHP, PV system and wind turbines.

So the conclusion is that with more interactions between DSO and TSO in future, better operation of the grid can be achieved at distribution as well as transmission level. But also that this kind of interaction is needed, since more power generation as well as active loads will come in future at distribution level and are expected to take part in the day-ahead as well as the balancing markets.

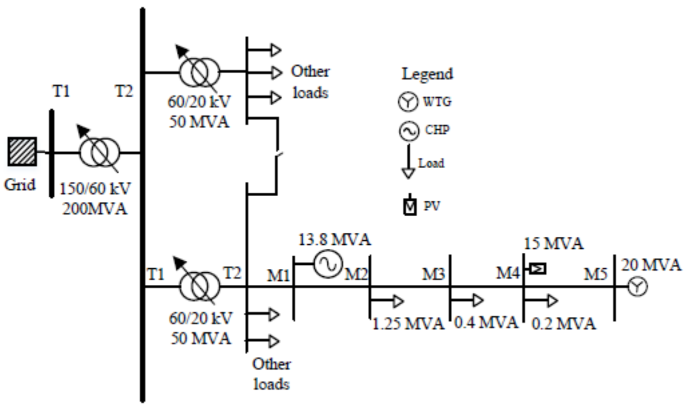

Figure 32. Modified MV network based on real network grid in Støvring Denmark [9]

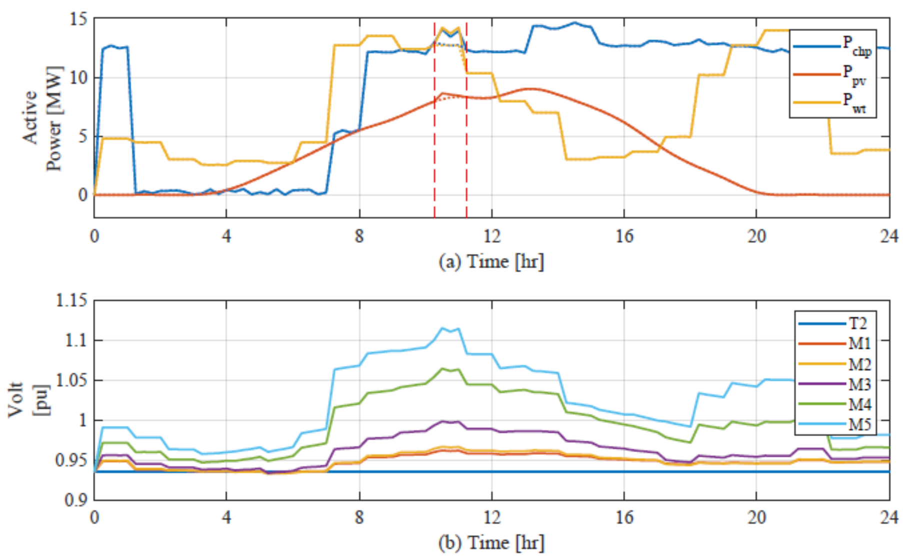

Figure 33. Simulation without TSO-DSO interface. a) active power of DERs based on hypothetical set points from TSO for up-regulation in the period marked with the vertical red color. b) voltages at MV nodes. [21]

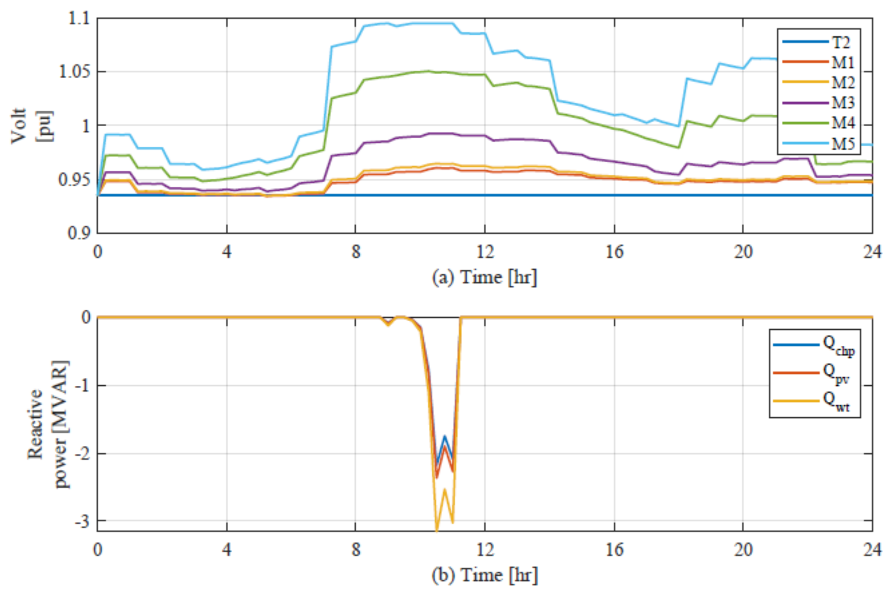

Figure 34. Simulation with proposed TSO-DSO interface. a) voltages at MV nodes. b) reactive power provision requested by the DSO for voltage control [21]

1.5.6. Success in realizing project results

Based on the above given results and outcomes of the project, it is seen that all the project objectives are addressed and research results has been provided for the different objectives. Some of the set up methods are further documented with demonstrations in real network grids or in laboratory.

The project was set up as a research work, and in this way it was not expected, that the project should result in increased turnover, export or employment for the involved distribution companies, consultants and industry. But since the state estimation procedure is verified in real network, it could be expected that this have a shorter way to real life application, compared to the set up control methods. The control methods with rather detailed new complicated mathematical formulations are still at a high research level, and more demonstrations and prototypes with application of the methods are to be tested before this can be seen in real applications in future. However, such control methods are needed in the future automated distribution grids, why the research results for sure have good later application possibilities and are of high interest for the rest of the research world.

One of the main goals seen in the project, was that the state estimation and control should be done with as little measurement as possible. The project results has actually justified, that it is not necessary to measure in real-time at all nodes to have a good state estimation of what is happening in the distribution grid. In this way for sure the project results have paved a way for the distribution companies to set up state estimation procedures without a need for a huge investment in new equipment. Further, the distributed control method together with the set up hierarchical control structure, where real-time control are performed autonomously at DER level using droop control, also shows a way for control at distribution level with minimized use of communication lines and thereby limited new investments for being able to perform the control. On the other hand, if a centralized control are to be used, then a huge investment in needed communication can be expected.

A total of 13 conference and journal papers are already published [10-22], and at least 3 more are under review together with a book chapter. Further, two PhD thesis are made reporting the results from the project. Also milestone reports are made, which are distributed to the partners of the project.

1.6 Utilization of project results

As mentioned in section 1.5.6 this project is a research project which were initiated under the Forskel programme, and in this sense it was not expected that the project should lead to new business plans or direct commercialization for any of the involved participants. The expected outcome of the research project was to explore how to automate the distribution system with as less measurement and communication as possible. The project results have demonstrated that state estimation can be done based on only few new measurement devices placed at MV and LV level, using existing information from smart meters and SCADA measurements, which are used to generate pseudo measurements based on forecasting techniques. This way of doing the state estimation in LV and MV grids are close to real utilization for distribution companies, if they want to have more information of the states in their grids. Both the distribution grid operators, ABB and KEnergy gained also real experience on where and how to set up the measurement devices in the grids due to the actual demonstration in Eniigs grid.

Regarding the control and protection methods and net-reconfiguration issues, the gained results are mainly at research level, so the outcome of the project for the

project partners are mainly more knowledge about future possibilities for their grid, but they need new commercial actors to actually implement and test these kind of control systems. ABB could be one of such actors, but more research and demonstration has to be done, before the actual implementation.
Aalborg University, will continue with the research in this area based on the results gained so far, since the topic has high interest in the research within power systems and the project members are very active in Cigre, were there are good possibilities to have further connections with actors and universities exploring new ideas for automation of the distribution grid.
As mentioned in the project result, the automation of the distribution grid is a part of the future energy policy, since it is necessary to automate the LV and MV grid if more DERs and demand response from new high energy intensive loads like heat pumps and electrical vehicles are to be realized. This integration of DERs and application of new loads are needed to get a 100% fossil free and CO_2 neutral energy system before 2050.
The results from the project has been disseminated as mentioned by 13 papers [10-22] published in high class international conferences and journals, besides this also two PhD thesis are made. A project homepage have been made, from which access to all published papers will be available together with links to two PhD thesis [24]. The results from the project has also already been used in different PhD courses at Aalborg University ie. Dispersed generation of electricity[2], smart distribution systems[3], Building the Bridge between Electrical Grid Control and Communication in Smart Grids[4] , and project results from the project has also be used during a tutorial on automation systems for distribution grids given at a the CIRED conference in Madrid June 2019 and two CIGRE conferences in Aalborg June 2019 and in Chengdu September 2019.

1.7 Project conclusion and perspective

This project has focussed on cost effective automation of the distribution grid to enable future high penetration of DERs and application of demand response to pave the way towards a fossil free and CO_2 neutral energy system. The idea has been, to use existing meters and measurements in the grid more effectively and applying as little new measurement, communication equipment and control devices as possible.
The project results have shown that it is possible to have a full observable grid and perform state estimation for all nodes, with installation of only few new measurement devices performing real time measurements. A procedure for finding the minimum and optimum placement of the new measuring devices are set up and tested with simulations and finally verification in a real grid. State estimation are performed using measured real time values from the few new devices supplemented by pseudo measurements, which are found using forecasting techniques from older measured values from the smart meters at the private households.
In the project it is also shown how this state estimation gives input to a set up hierarchical control system. In this system the control are split up into three levels. One level giving hourly set point values based on input from the day-ahead market, the second level performing inter hourly control with set point values given in a time-scale of 5-15 min, and finally a real-time control which are based on autonomous control performed at the individual devices based on local measurements of

[2] https://www.et.aau.dk/events/show/industrial-phd-course--dispersed-generation-of-electricity.cid344345
[3] https://www.et.aau.dk/events/show/industrial-phd-course--smart-distribution-systems.cid391602
[4] https://phdcourses.dk/Course/64950

voltage or frequency and droop control. It is recommended to use distributed control with local grid-controllers to minimize the need for fast communication lines. Advanced optimization procedures are set up in the control methods, to find the best scheduling for application of the individual devices and at the same time obeying the grid limit conditions and minimize power losses and costs for the individual costumers.
In the report also protection issues are addressed, since this is also a part of the future automation of the distribution grid. Procedures for adaptive protection to avoid protection blinding and false tripping is set up, and also a net reconfiguration procedure is simulated, this operates in normal condition of the grid to minimize power losses.
Finally, future expected need for DSO-TSO interaction is analysed, and simulations are shown for how the power generation and demand response from the distribution grid can be used to provide needed ancillary services at transmission level without violating the voltage or power limits in the distribution grid.
The set up state estimation procedure together with the control methods allows the distribution companies to have higher utilization of their grids operating the grid closer to the limit and might also postpone the need for network reinforcement. Further, an extended DSO-TSO interaction as described in the project allows better possibilities for the DSOs to provide ancillary services, which is needed to integrate more fluctuating renewable generation both at distribution level as well as on transmission level and at the same time ensure reliability and security in the grids.

Annex

1. Deliverable: WP1 -Use Cases and System Architecture for Active Distribution Grid Management, Basanta Raj Pokhrel and Karthikeyan Nainar, October 2016
2. Deliverable: WP2 - Hierarchical and Distributed Control Framework for Active Distribution Grids, Karthikeyan Nainar, November 2017
3. Deliverable: WP3 - Enhanced Observability of Active Distribution grids, Basanta Raj Pokhrel, March 2018
4. WP4 - Network Reconfiguration and Adaptive Protection Algorithms for Active Distribution Grids, Karthikeyan Nainar, January 2019
5. Deliverable: WP5 - Advanced Distribution Grid Management System for Active Networks, Basanta Raj Pokhrel, Karthikeyan Nainar, December 2018
6. WP6 - Performance Assessment of Intelligent Distribution Grids, Karthikeyan Nainar, Basanta Raj Pokhrel, October 2019
7. Deliverable: WP7 - Distribution Grid Interface between System Utility and Electricity Markets, Basanta Raj Pokhrel, Karthikeyan Nainar, February 2019
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B. R. Pokhrel, N. Karthikeyan, R. Sinha, B. Bak-Jensen, and J. R. Pillai, “Architecture of integrated energy systems,” Book chapter on Reliable and Sustainable Electric Power and Energy Systems Management., Springer

To be submitted
N. Karthikeyan, J. R. Pillai, B. Bak-Jensen, and J. W. Simpson-Porco “Hierarchical distributed predictive control for demand response in ac-tive distribution networks”, IEEE Transactions on Power Systems

B. R. Pokhrel, B. Bak-Jensen, J. R. Pillai, “Testing and
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