Final report

1. Project details

Project title	Optimal Voltage Regulation in Medium Voltage Networks
File no.	64017-0029
Name of the funding scheme	EUDP
Project managing company / institution	Dansk Energi Vodroffsvej 59 1900 Frederiksberg C
CVR number (central business register)	14 15 66 16
Project partners	Dansk Energi Tampere University RAH Net A/S Maschinenfabrik Reinhausen GmbH
Submission date	18 February 2022

2. Summary

Danish summary

Med elektrificeringen af transport og varme og mere distribueret elproduktion i distributionsnettet, vil der kunne opstå spændingsproblemer i nettet, og specielt i ældre net. I en situation med høj belastning, men lav produktion, vil spændingen kunne falde under de tilladte spændingsgrænser. I det modsatte tilfælde, med lav belastning og høj produktion, kan der komme for store spændingsstigninger i nettet. Dette vil kræve store reinvesteringer i distributionsnettet. OVR-projektets mål var at demonstrere et intelligent spændingsreguleringssystem, som vil kunne øge kapaciteten i nettet, reducere tabene og forbedre spændingskvaliteten, og dermed udsætte mange af de dyre investeringer og forlænge levetiden for allerede eksisterende komponenter.

I en normal driftssituation i 10 kV nettet, sættes spændingen til 10,4 kV for at kompensere for spændingsfald i kablerne. I OVR-projektet har vi demonstreret et intelligent system, hvor sekundærspændingen på 10 kV siden af transformeren er flydende og ændres dynamisk alt efter spændingssituationen i nettet på et givent tidspunkt.

I løbet af projektet er der udviklet og demonstreret et spændingsreguleringssystem. Systemet har kontrolleret spændingen i et mellemspændingsnet i perioden juni 2021 til februar 2022. Resultaterne fra demonstrationen indikerer at, spændingsniveauet og systemtabene i demonstrationsnettet er blevet noget forbedret. Derudover er der ikke observeret negative effekter at have systemet kørende, dog er der observeret øget antal koblinger med viklingskobleren, fra et daglig antal på 7 til 9.

Endvidere viser analyserne, at spændingsreguleringssystemet har potentiale til at forbedre nettets evne til at optage/aftage ny produktion. Forudsat at systemet kører ved sin fulde kapacitet har det potentiale til at tredoble demonstrationsnettets kapacitet for VE-produktion. Alt i alt, anses demonstrationen som en succes fra et gennemførligheds- og ”proof of concept”-perspektiv.

English Summary

With electrification of transport and heat together with introduction of distributed energy resources in the distribution grid, voltage problems can occur, especially in older networks. In high load low production situations, the voltage can drop below the limits specified in the grid codes. In the opposite situation with low load high production, the voltage can increase beyond the specified limits. This will lead to grid reinforcement to massive investments in distribution grids. The aim of the OVR-project was to demonstrate a secondary voltage regulation system, that could increase the hosting capacity, reduce losses, and increase voltage quality in medium voltage networks, and thereby postpone investments and extend the lifetime of existing components.

In normal grid operation of 10 kV networks, the voltage is set at fixed setpoint of 10,4 kV to compensate for line drop. The demonstrated OVR-system introduces intelligent voltage control with a floating setpoint to dynamically change the voltage based on the state of the network.

During the project a voltage control system was developed and demonstrated. The system has been controlling the voltage at a HV/MV substation between June 2021 and February 2022. There is indication that the demonstrated system improved the voltage level and grid losses of the demonstration network slightly. Additionally, no adverse effect due to the use of the system were observed, though there is an increase in daily tap operations from 7 to 9 tap operations.

The hosting capacity assessment realized for the demonstration network shows excellent potential to enhance voltage control and hosting capacity in the distribution network. The secondary voltage control system has the potential to triple the hosting capacity of the demonstration network. All in all, the demonstration can be considered successful from feasibility and proof-of-concept perspective.

Content

3. Project objectives

The aim of this project is to develop and demonstrate a secondary voltage regulation system that will

- increase the capacity of distribution networks to host more distributed generation, electric vehicles, heat pumps, etc. and facilitate more active operation of demand response and storage at different energy, ancillary and flexibility service markets in that way,
- enhance the performance of distribution grid by improving voltage quality and reducing losses, and
- postpone the huge investments costs for grid reinforcements.

The project is unique because it utilises the hardware already installed at the medium voltage transformer stations and makes active use of the smart meters' data.

The share of distributed generation is increasing. New wind power, photovoltaic etc., are continuously being connected to the distribution network as new customers, and among existing customers by transforming them as prosumers. During periods of high wind and/or high solar radiation, the production from wind turbines and/or photovoltaics increases. Such a sudden increase in production can cause the voltage in the medium voltage network to increase above the allowed limits, especially when the consumption is low, and production is in remote (electrical distance) locations. The voltage rise is one of the main barriers of the hosting capacity of distribution networks. Alternatively, distributed generators will be curtailed to maintain the voltage within the allowed limits or in extreme cases generators may not be allowed to connect to a weak network before the grid expansion has been realized and therefore increasing grid investment cost if the operational safety margin is not satisfied in all possible conditions.

On the other hand, during low production and high demand situations the voltage will drop, thus, increasing the losses in the medium voltage network, and may eventually drop below allowed limits. Large new loads such as heat pumps and electric vehicles may have highly correlated consumption patterns, which risk increasing peak load. In similar way, the price-based control of prosumers or demand response will increase the peak loads in the distribution grid by increasing the correlation of consumption patterns among different kind of customers.

To increase the hosting capacity of the distribution network in such a way that it can host more load and more distributed energy resources, without compromising voltage quality, a secondary voltage regulation system has been developed and demonstrated in this project. The system will also be used to minimize network losses in the distribution system.

Already now, there are many HV/MV[1] transformers with automatic onload tap-changers (OLTC). Due to the increasing amount of distributed generation connected to the distributions network, the automatic voltage regulators (AVR) of OLTC are set to maintain a fixed voltage at the secondary MV busbar, rather than using a regulator with line drop compensation. This limits the hosting capacity of the network, due to voltage variations at the edge of the network caused by high load/no production and low load/high production situations. Line drop compensation is insufficient to handle complex voltage profiles caused by bi-directional power flows. If, for example, there is low load on a HV transformer, the optimal response of the voltage regulator will be different depending on if it is a sunny day with high PV production, or if it is the middle of the night, with low power consumption. Therefore, the primary voltage control at the transformer station (AVR of OLTC) alone is not enough for the future requirements to maintain good voltage quality in all parts of the distribution networks having decreasing, increasing and both kind of voltage profiles.

[1] In the Danish distribution grids HV (High Voltage) refers to 30, 50 or 60 kV depending on geography/DSO. MV (Medium Voltage) refers to 10, 15 or 20 kV and LV (Low Voltage) to 0,4 kV. In the case of the OVR project HV is 60 kV and MV is 10 kV.

With the increasing penetration of distributed generation and the increasing focus on harvesting the green energy, it's important to find new solutions to automatically solve voltage problems by optimally employing the transformers OLTC and other possible primary voltage controllers. The Figure 1 illustrates the concept of the demonstrated automation solution. The basic idea is to monitor the whole medium voltage distribution network and optimize the voltage control settings of AVR of OLTC based on that information. The demonstration was focusing on OLTC control alone, but the concept and the optimization can consider multiple controllers which are under direct control of DSO through ownership, connection requirement or a service contract. The automation solution is based on edge computing at HV/MV substation, remote reading of selected MV/LV substation measurements, grid analysis and optimization at edge computing platform and readjustment of control settings of primary voltage regulators. The system supports multiple information exchange protocols and formats, but is primarily based on IEC 61850 MMS messages for measurements and controls, and Common Information Model (CIM) for network model exchange, i.e. meaning that it is compatible with modern substation automation and control centre IT systems.

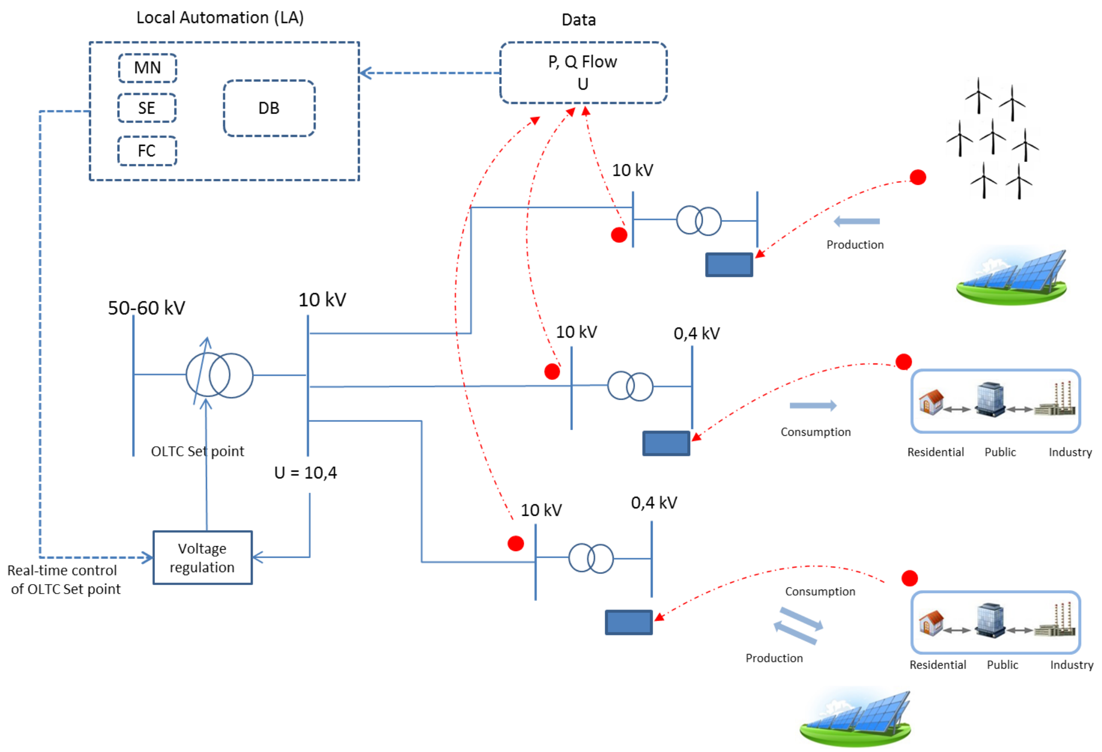

Figure 1: OVR-concept of advanced distribution grid monitoring and control.

In this project, a local automation system based on edge computing has been developed to host several functions to realize the secondary voltage regulation system. Primary functions utilized in the demonstration are based on monitoring, state estimation, forecasting and optimal power flow algorithms. Those algorithms are operated in the local automation system installed at the HV/MV transformer substation to perform five functions:

1. Monitor the distribution network in real-time by collecting measurements from substation and few strategically selected distribution transformers at the distribution network.
2. Estimate the state of the distribution network by utilising the state estimation algorithm, the measurements collected and filtered by the monitoring functionality, the pseudo-measurements of aggregated load profiles of low voltage network customers and the grid model.

3. Forecast the state of the distribution network e.g., 24 hours ahead in time and thereby prediction power flows to minimize tap operations.
4. Optimize the settings of primary voltage controllers of the network area by minimizing the cost function consisting of network losses, production curtailment, voltage deviation and number of tap changer operations within given network constraints and given control resources.
5. Adjust the control set-points to the AVR of OLTC dynamically. The voltage levels in complete medium voltage network are controlled in near-real time to keep them on acceptable level not only at the substation but in all parts of the network.

The Figure 2 represents the outcome of the control setting adjustment when AVR of OLTC is adjusted. The voltage profiles indicated by red colour are the outcomes of state estimation when the distributed generation has raised the voltage above the maximum limit during a low load and high production condition on one of the medium voltage feeders. At the same time the largest voltage drop among all feeders is just below the nominal voltage (V_n). The optimization easily finds a feasible solution in this case, which is indicated by the blue coloured voltage profiles. After adjustment of the control settings of AVR of OLTC the tap changer operates, and the voltage profiles (blue colours) are confirmed by the monitoring and the state estimation functionalities. More voltage controllers are included within the optimization and readjustment loop, better changes the automation system must maintain acceptable voltage levels and to minimize network losses, voltage deviations and production curtailments. Therefore, the reactive power or voltage control of distributed generation is strongly recommended to incorporate in the automation system.

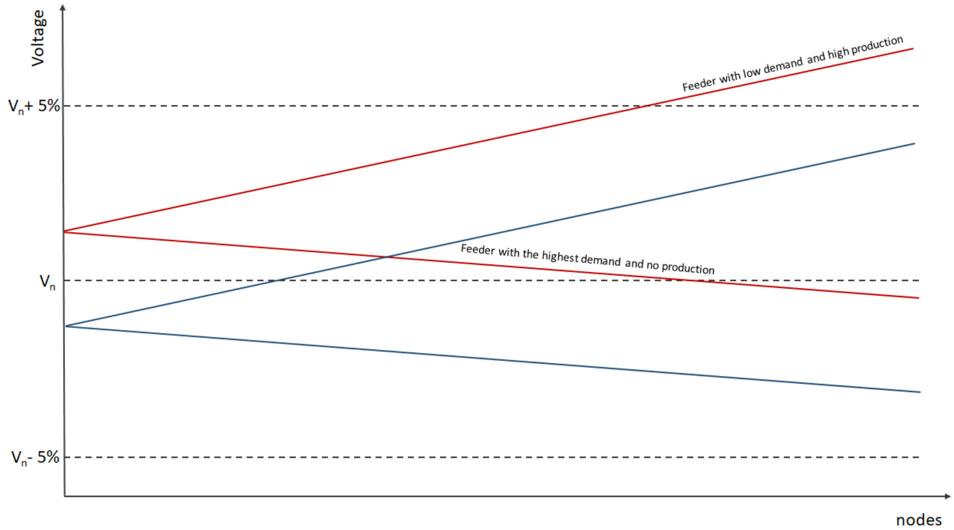

Figure 2:Voltage scenarios along distribution feeders.

The project has demonstrated the proposed automation system and functionalities in medium voltage network owned by the Danish DSO RAH Net A/S. The 60/10 kV transformer station and eight medium voltage feeders have been used in the closed-loop field demonstrations. The transformer has a vacuum online tap-changer, thus the cost of operating it is quite low compared to the network losses. Medium voltage network is a mix of urban, semi-urban and rural areas, cable and overhead lines, and feeders consists of production only, load only and mix of both. The demonstration site is located at the Danish mid-Jutland region in a town called Ringkøbing where RAH Net A/S is the operating DSO in the area.

The developed functionalities and automation system has also been tested and demonstrated at the real-time digital simulation laboratory owned and located at Tampere University in Finland.

Objective of the project

The objective of the project was to develop, validate and demonstrate a local automation system and functionalities for the secondary voltage control that automatically regulates the voltage settings of primary voltage controllers like AVR of OLTC on HV/MV transformers based on real-time monitoring and state estimation data and forecasted states of complete medium voltage network. The main goals of the project are listed below:

1. **Increasing the hosting capacity of the distribution network**
   The local automation system that will be installed at the HV/MV transformer station in Ringkøbing will utilize online measurements collected from different locations of the distribution network to estimate the state of the MV network. By utilizing historical data from smart meters in the underlying low voltage network, the state estimation (SE) is extended to include the low voltage network by statistical methods. The historical data will in addition be used to forecast the state of the distribution network e.g., 24 hours ahead in time. Having an estimate of the state of the network in the present and in the near future will allow the system to expand the operational band of the online tap-changer, thus increasing the viable number of distributed generators connected to the distribution network without violating the voltage constraints.

   Furthermore, having an estimate of the state of the network and a forecast of possible voltage deviations will allow the system to react efficiently and quickly to eliminate such voltage problems.

2. **On load tap changer optimization**
   Based on the forecasted state of the network, the local automation system installed at the HV/MV transformer station operates on scheduled intervals e.g., once a day (as soon as new forecasted states are available) to find the optimal set points for the OLTC that ensures minimum losses and maximum integration of distributed generators without compromising voltage quality. The OLTC set points will be configured by a (newly developed) secondary controller, while the primary controller is mostly like the feedback controller in use today.

   Within the boundaries of the voltage constraints of the network, the local automation system will try to reduce the losses in the network. The optimal settings for loss reduction will balance no-load “iron” losses (which increase with higher voltage) with resistive “copper” losses, which decrease with higher voltage.

   As a mechanical device, the tap-changer has significant operating costs, and fluctuating power sources threaten to increase wear and tear. New technologies with online vacuum tap-changers (such as the one installed at the RAH NET A/S demonstration site) increase the lifetime number of operations of online tap-changers, thus reducing the costs associated with its operation. The local automation system developed in this project will in near real time estimate the network losses and adjacent tap-changer positions. The automation system compares the change in cost of network losses to the cost of operating the tap-changer, and actions are decided accordingly.

3. **Applicability**
   One of the strong sides of the project is the presence of Maschinenfabrik Reinhausen GmbH (MR) in the project consortium. MR is a voltage regulation systems supplier that supplies systems not only for the HV/MV transformer that will be used for the demonstration in this project but also commercially around the world. Besides allowing and helping the developers to get access to the voltage regulation system at the demonstration site, MR will take the role of ensuring that the development in the project will not end up as a theoretical study that is impractical or very costly to implement in the near future. Furthermore, MR will analyse the final concept and the developed algorithms and propose a marketable version together with recommendations in a separate deliverable. The deliverable will discuss the

applicability of what has been developed in the project, and what research areas need to be investigated to move from the research and demonstrations to field applications and commercial use.

4. Project implementation

This section describes the project implementation. The project has applied for three extensions for a total of two years. The reasons for this are described in the next sections.

4.1 How did the project evolve?

The project has been delayed and the finalization of the project has been postponed for two years, due to many unforeseen problems. These are listed in the below Table 1 and elaborated in the next sections. Albeit slow, there has always been progress in the project. However, many issues were to be resolved, many of which could not have been prepared for.

Table 1: Unforeseen problems in the project, its estimated caused delay and the process of solving the issue

PROBLEM	ESTIMATED DELAY	PROCESS
Employee turnover	1+ years	Approx. 7 of the key personnel involved have stopped in the duration of the project. New employees with less experience needed to get acquainted with project, and some of the very technical aspects of SAU had to be learned. This is hard to estimate the effect of, but probably more than 1 year delay due to employee turnover.
GDPR	3-6 months	Long discussions in legal departments
Network model	6-9 months	Manual in-field verification. Communication with model provider.
SCADA	6 months	Long process with SCADA provider, no solution could be found.
CHP-plant	2 months	Synthetic profiles had to be made and implemented
Crashing of SAU	2 months	Identification of problem, re-programming of database functions
D.5.2	3 months	Deliverable 5.2 was not delivered as planned, and TUNI and DE had to write the deliverable.
IT security measures	3 months	Among other things a measurement system (Rogowski coils) had to be installed at the substation, tested, and implemented in SAU.
COVID-19	Unknown	The pandemic has had an influence on the project progress. There has been a travel ban, making all work at the substation remote.
Project manager on sick leave	Unknown	The project manager had been on parttime sick leave from September 2021 to November 2021
TRL	1+ years	Rewriting several key functions in SAU. New employees meant that the project had to start from scratch from a learning perspective.

Many of the problems took months to resolve, and many were resolved in parallel with each other. For example, network and SCADA-issues was huge contributors to the delay of the project. Both these problems took months to resolve, and both issues were dependent on third-party companies to deliver data and support. The technical aspects of these issues are described in detail later. In relation to how the project evolved the SCADA-data exchange issue will be used as an example.

Originally the idea of the project was to get close to real time data from SCADA via an exchange server. Due to IT security issues, the OVR-system was not allowed to be connected to RAH's SCADA-system. Therefore, it was agreed that SCADA data was to be exchanged through an exchange server. Getting close to real time data was crucial for the state estimation to be accurate enough for controlling the voltage. Therefore, SCADA data exchange was very important for the demonstration phase of the project. The third-party company did its best to solve the issues, but in the end the SCADA provider could not provide a fast enough solution, and hence the issue remained unsolved. Therefore, a plan-b had to be implemented and several propositions were discussed. It was decided to implement a solution with Rogowski Coils on all feeders, to have close to real time measurements at the 10 kV busbar. This implementation took time as all the infrastructure surrounding such a solution had to be found, bought, and developed, before it could be implemented.

The above example is just one of many examples of unforeseen problems the project faced. Because the OVR-system was to be implemented in a real network with costumers, understanding underlying causes of the issues was important, as the consideration of RAH's costumers was the highest priority in the project. A voltage regulation system that would endanger the level of supply security, was not an option and therefore it was of outmost importance that the solutions provided, was tested thoroughly, so that RAH was confident that the system did not endanger its costumers before starting the demonstration.

Employee Turnover Rate

Many of the problems that arose during the project, was related to employee turnover rates. At least four key employees at Tampere University stopped during the first year of the project. This being the personnel that had developed the algorithms and control functions, delays in the project were inevitably. The same problem was present in Dansk Energi, where four key employees related to the project left the company.

The OVR-project is a technological advanced project, and losing key personnel highly affects the progress, as new personnel to start do not have the same competences as the personnel leaving. This is a risk in all such project, where technology is to be developed.

The new personnel have made a great effort to familiarize themselves with the algorithms, database structures, communication protocols, etc. This has taken a long time and has been a long process. However, the project has been finalized and in the end the project partners were able to start the demonstration.

4.2 Risks associated with conducting the project

The OVR-project was planned as a relatively short demonstration project. However, the project's goal was quite ambitious, going from a theoretical study in the IDE4L-project to implementing a live demonstration setup, in the OVR-project. Therefore, there was always a certain amount of risk associated with conduction the project, worst case scenario being not able to get approval to start the demonstration by RAH.

The main risk in the demonstration of the system was, that the system could endanger the security of delivery of electricity for the approx. 2500 customers that is connected to the feeders involved in the project.

RAH has for the start of the project, made it clear that their main focus is their customers, and therefore, the system had to undergo strict testing at site before the system could be commissioned to start the demonstration.

One of the main concerns has been overvoltage in case of automation system failure. Therefore, several safety measures had to be made.

Several safe mode solutions were implemented as risk mitigation measures. SAU has several internal processes for ensuring safe operation.

The internal safe mode (software safe mode) is activated if new measurements are not registered. Further, there is a watch dog, which is hard coded to only allow setpoints within the allowed operational bandwidth e.g., 10,35 kV to 10,45 kV. If an OPF result is outside this bandwidth, the watchdog automatically adjusts the setpoint to the upper or lower bandwidth limits accordingly.

Another risk mitigation measure has been to have a test server at the university in Tampere. Having this was a good decision, this meant the project could continue the development of the system without visiting Denmark. This meant the project partners could do final tests in the laboratory before uploading updates to the installed system in Denmark. Therefore, a replicated SAU ensured system stability before uploading. This meant less travel between Tampere and the demonstration site in Ringkøbing, which proved especially with the travel ban in relations to COVID-19.

Realising the demonstration system as an edge computing solution, is also a risk mitigation measure, as there is no need for connecting to RAH's network.

The safe mode device can stop demo in situations where not enough technicians are available i.e., it is safe to start the demonstration even if situation in RAH is uncertain at the moment.

Demonstration during summer months may provide too optimistic results due to small amount of voltage drop compared to winter months, and therefore optimal voltage control has enhanced possibilities to reduce the voltage level at medium voltage grid. This may lead to a conclusion of too optimistic benefits related to hosting capacity.

4.3 Implementation develop as foreseen?

The project did not develop as foreseen, as the project end date was extended three times, two years in total. As mentioned above, the project faced several time-consuming problems.

Milestones

The below table shows the project milestones and the date and their status. As shown in the table below, the milestones have been reached, however some milestones need commenting.

Table 2: List of Milestone and status

Milestone	**Status**
M1 Project start - Kick start meeting	Done
M2 Specification of the input data required for the algorithms to be used by WP3.	Done
M3 The development of all algorithms is complete and short documents describing each algorithm with an installation guide	Done
M4 All RTDS test activities and simulations are finished and algorithms and communication platform ready for demonstration	Done
M5 Field demonstrations are up and running	Done
M6 Final report	Done
M7 Midterm public workshop	Done

M3: The algorithms are developed and implemented. All algorithms are documented, but these are not published, as the documentation contains sensitive information. The documentation can be provided by contacting Tampere University.

M4: All Real Time Digital Simulation (RTDS) test activities and simulations are finished and algorithms and communication platform ready for demonstration. Many of the testing activities was moved to live testing at site. Many of the tests had to be tested in RTDS-laboratory, such as the parallel operation of two AVRs. Some of the RTDS-testing was not performed as planned e.g., short circuit tests, as it was realized that short circuit protection, would react within millisecond, whereas the voltage regulation would react within minutes, and therefore have no practical significance for the operation of the grid or the OVR-system.

M7: Midterm public workshop was done in a different way than first planned. Because the demonstration started too close to the deadline of the project, it was decided to have a two-part semipublic workshop to sum up the results of the project for MR, for them to be able to finish their deliverable. At the start of the project, it was planned one full year of demonstration, with a midterm public workshop. However, as the demonstration phase has only approx. six months, it made little sense to organize a workshop after just a short period of demonstration. MR's contribution to the project was to provide a TapCon and consulting the operation of the TapCon. So, for MR to fulfill their deliverable, it was instead decided that the midterm workshop, should be utilized to reacquaint MR to the project. Therefore, a two-part semi-public (invite only) workshop was organized. The first part of the workshop was an overview of the technology, and the second part was to present the results from the demonstration and a longer Q&A session between MR to TUNI.

Dealing with delays

The implementation of the project would have been less delayed if the employee turnover rate was lower. Having inexperienced personnel to develop such a technologically advanced system, cost much time.

As time was running several measures was implemented to make sure the demonstration phase of the project could be realized. A weekly status meeting between TUNI and DE was started, to improve the communication between the project partners, and solve problems faster and when possible, in collaboration.

Further, a steering group committee was established to push development forward and make decisions on implementation of the system. The steering committee did a great job making sure that the focus was on starting the demonstration, and therefore prioritized the tasks and cutting tasks that were not pushing towards the demonstration.

Shorter demonstration period than planned

In the original project proposal, at least one year of demonstration was to be completed. However, the demonstration phase was delayed so that only 7 months of demonstration could be realized. However, the shorter demonstration phase, do not interfere with the overall objectives of the project, and a longer demonstration phase would add little extra value add the project.

The benefit of a longer demonstration period would have been to demonstrate the long-term stability of the system. Further, it might have been time to experiment with larger control bandwidths to prove that the system could bring even more benefit to the DSO grid.

As the Substation Automation Unit (SAU) was installed at site and all the algorithms running and collecting data from January 16th 2020, TUNI can calculate backwards all the control actions of SAU. For this reason, it is possible to calculate long-term benefits of the system without a prolonged demonstration period.

It was agreed that it would be better to demonstrate few months, than to apply for even more extension of the project. This decision was agreed with all project participants and EUDP.

Forecasting algorithm

The developed technology was not the same as what was planned, as the cost of OLTC operations was not as high as first thought. Therefore, the forecasting algorithm mentioned in the project description was not implemented in the final solution. The forecasting algorithm was to forecast the state of the distribution network e.g., 24 hours ahead in time, and to realize predictive optimization of distribution network states. The forecasting algorithms was developed, but never implemented in the final system. There are several reasons for this:

1. The original idea was to be able to implement predictive Optimal Power Flow (OPF). For that application it would be crucial to have a forecast the state of the distribution system 24 hour ahead. This way it would be possible to get a prediction of the power flows, and thereby the voltage of the system. This would help to minimize unnecessary tap operations. However, the OLTC at RAH is a vacuum type, and therefore the cost of operation is close to zero. Due to this, the developed forecasting algorithm was not implemented in system. However, had the OLTC been of the oil-filled type, the cost of operation would be higher, and in such a case, the forecasting algorithm would have been more relevant.
2. The idea of predictive OPF is reasonable, if the forecast accuracy is satisfactory or the variance of accuracy is small enough. However, this is not always true in real-life. Few hours delay in the prediction when e.g., stronger winds will reach the shore, makes a large difference in the predicted network states. Therefore, the benefit of avoiding tap changer operation becomes very uncertain. Due to these considerations, the implementation of predictive OPF was considered unnecessary for the demonstration and uninteresting from commercial perspective.
3. An implementation of the forecasting algorithms into SAU would have delayed the project further.
4. The change in personnel at Dansk Energi resulted in change of focus. The project manager stopped at Dansk Energi, and therefore the focus of the remaining personnel had to change from technical tasks to making sure that the project could be realized.
5. The delay of the project. Hours meant for developing the forecasting system was moved to realizing the demonstration phase of the project, and the finalizing of the project. Therefore, it was not possible to implement even more algorithms into the SAU.

The forecasting algorithm is developed, but was never implemented in the final solution, and therefore it is not as good as it could have been. This is described in short in section 9.1 and the results are presented in section 5.5.

4.4 Unexpected Problems

Even though the OVR-project met its goals in the end, the process/road of getting to the demonstration phase has been full of obstacles. The project partners are all thankful to the EUDP for showing patience and goodwill, so the project could fulfil its potential.

This section describes the implementation of the project and the problems that arose during the project period. Many of these problems are described in the CIRED paper [1], "Lessons learnt in implementation of coordinated voltage control demonstration".

GDPR

The first main obstacle was how the project could utilize smart-meter data, and other data that fell under the GDPR legislation. At the time of the project start the legislation was very new, and therefore it took time to understand the new legislation, the requirements in a R&D project, and how to implement this in the setting of the demonstration and in data processor agreements etc. This took several months of legal work from all TUNI, RAH and Dansk Energi before a data processor agreement was in place. Among other things, there was a need for finding solutions that worked for everybody involved, where personal data was not stored in Random Access Memory (RAM) and therefore could be found by IT-criminals.

Network Model

One on the main problems that was not expected in the project was the time spent on getting a workable network model. The accurate and up-to-date network model is very important for the correct and accurate enough operation of the developed automation system and functionalities. Verifying and correcting the network model took a very long time and is one of the main reasons for the project's long delays. This process is also important learning related to commercialization of the prototype and to project engineering of such product.

First iteration of the network model was exported in a way that the costumers in the network model could not relate to customers in the smart-meter-data. The 22-digit metering point id was exported as an integer, which resulted in that some of the digits were cut off. In the next iteration of the network model the number of digits were corrected. However, still it was impossible to relate network topology to the smart meter data. It took several iterations before a verified model was exported. The process of receiving a network model that could be verified was long and tedious and took several months.

After the export was verified, a new issue arose. When comparing the state-estimation results with the measurement system, it became apparent that the outcome of state estimation was not accurate enough. This issue needed to be fixed, as an inaccurate state-estimation meant, that the optimization function would not be controlling the true state of the distribution network and the potential control-band would be too narrow to be on safe side in real-life demonstration. In the below figure this is illustrated for low voltage measurement and estimation. The voltage is plotted, and the black line is the measured voltage at the primary substation. The red line is the voltage estimate of the secondary substation (station number 1008). The dotted blue line is the measured voltage at the substation on the LV side of the transformer. As can be seen, the measured voltage is much lower than the estimate. As stated above the high deviation between the measured voltage and the state estimation, would mean that the control band the project could use would be very narrow.

After some consulting with Dansk Energi and RAH it was discovered that the error was constant, and that the probable cause was that the tap-positions in the network model were not updated. In Figure 3 the dashed blue line is shows the AirVantage measurement of the voltage at substation 1008. The red line is the state estimate. The solid blue line is the AirVantage measurement corrected for one tap-step (+2,5%). This correction meant that the estimate and the measurement aligned at satisfactory level, and that the state estimation was accurate enough to be confident that the demonstration could be realised. However, several of these "problematic" secondary substations had to be verified by a technician checking the true tap-position of the secondary transformers and adjusted accordingly in the network model.

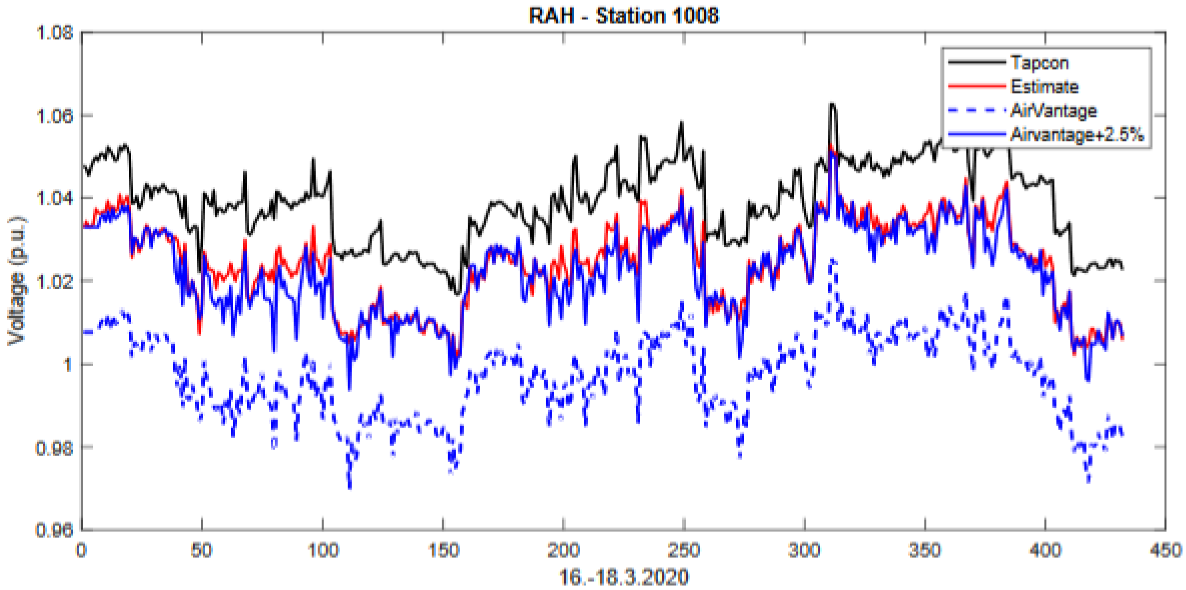

Figure 3:State estimation verification test.

Due to medium voltage network topology changes, the network model in the automation system was updated few times. Because the project did not implement the automated updating of the network model, this was needed to realize manually, which naturally took some time and effort to verify the network model again. Due to misunderstanding between project partners, one of the power quality measurements was left behind an open switch (i.e., measurement did not belong to network area anymore) and the network model in the automation system was not updated accordingly. All this resulted in few weeks delay due to error searching in the state estimation functionality. Again, important learning came out from this experience to highlight the importance of automatic updating of network model for the commercial product.

Some other smaller corrections were also realized for the network model after calculating fault current levels in different parts of the network.

SCADA

One other factor for delaying the project was due to cyber security issues. In the original project proposal, the idea was to get measurements from SCADA directly, and in a commercial system this would be the way the system would be implemented. However, being connected to SCADA via ethernet, would be a huge risk in terms of cyber security, as the OVR-system could be a way into RAH's for cyber criminals. To avoid this, it was first decided that the SCADA provider, should use an exchange server for providing the SCADA-data.

By default, the SCADA-provider could provide 15 min resolution data, with 1 hour delay. For a system operating close to real time, this was not acceptable. The SCADA provider tried to solve this issue, but it could not be done. Therefore, a plan-b, had to be implemented. The solution was to install Rogowski coils on all feeders and to build a data logging system with IEC 61850 MMS server. This solution was simple, cost effective and accurate enough, but again created extra work and delay in the project.

CHP-plant

In the mixed feeder “Ringkøbing KVV”, a CHP-plant is located. The power flow on this feeder is 17pprox.. 2 MW. However, when the CHP-plant is producing, is has an output of 9 MW. Due to the size of the CHP-plant, the feeder voltage is changing the most during the ramp up and down of plant. Therefore, the OVR-system, would provide most value during the CHP-plant’s ramp up and down cycles.

At the start of the project, the size of the CHP-plant was unknown, and was assumed much smaller. Therefore, no special attention was given to the CHP-plant. However, as the testing was proceeding, it was realized the CHP-plant needed special attention. Therefore, some of the measuring equipment had to be moved to the CHP-plant, so that it could be monitored more closely, and that SAU could use the input, to provide more accurate state estimates.

After monitoring the system, during ramp up and ramp down of the CHP-plant it was realized that the ramping-time measured at the CHP-plant, was several minutes different from the feeder measurement taken at the primary substation. The difference in measured ramping time meant that the algorithms in SAU did not converge during ramping. This was problematic as the ramping of the CHP-plant changes the voltage in the system.

Therefore, were several attempts to get a deeper understanding of the cause of this behaviour implemented. First attempt was to verify the measurements from the installed measurement system (Rogowski Coils) at the primary substation with measurements from the SCADA system. These measurements matched and it was concluded that the measurement system at the primary substation was not the problem. Another attempt was to verify the AirVantage measurements at the CHP-plant. A measuring device was sent from Finland, to be installed at the CHP-plant to verify the measurements. The control measurements matched the AirVantage measurements, and the conclusion was that the OVR measurement system behaved correctly. In parallel with measurement verification a simulation study was done in PSCAD, but it was not possible to verify the root cause of the mismatch of measurements.

Due to time constraints the root cause of this has not been found. To realize the demonstration phase of the project, it was decided to make synthetic ramping profiles. Based on all recorded ramping cycles recorded, a synthetic ramping profile was made, tested and implemented. When the CHP-plant now is ramping, the synthetic profile has priority over the actual measurement. This solution provided better results for the state estimation compared to the measurements and was used in the actual demonstration.

Crashing of substation automation system

During the system testing, the developed substation automation system crashed and could not be reached. The only way to reach SAU was a hard reboot at the substation.

After examining the log files, it was concluded that the Matlab written algorithms did not react well with the Java based database interface. This is a known issue with Matlab. It was first tried to solve this by updating Matlab and Java in SAU. However, this did not resolve the issue. Therefore, the database interface was rewritten from Java of Python, which solved the issue.

Remotely working with Hardware and software on site

The first version of the prototype was installed in June 2019. Several modifications for the network model and configuration of functionalities were realized. Measurements were collected most of the time, which might be utilized for example in the hosting capacity simulations, although the secondary control itself was not yet functioning.

Second visit to update data logging part was realized, because remote fixing would have been too difficult to realize. During COVID-19 pandemic period all modifications were realized remotely. This consumed a lot of data quota of the 4G connection and therefore the access was time to time disconnected. Tampere University had a prototype mock-up for testing and development purposes, but not all problems were visible in the prototype mock-up, and therefore a lot of problem solving was needed to be realized over slow remote access with the prototype at the demonstration site. All these created delays for the progress of the project.

Prototype TRL was below the expected level

The basic idea of the project was to use the outcomes of the IDE4L project where both TUNI and Dansk Energi participated, for a relatively easy implementation of the system in the OVR-project. However, the technology readiness level was not as high as expected, and in combination with key personnel quitting, the project experienced delay in the progress. This meant that the project in many aspects had to start from scratch at least from the learning perspective.

This have meant that the database structure had to be rewritten, which was a long and tedious task. The AirVantage interface of IoT connectivity platform for power quality measurements, MMS client for reading data logger of substation measurements and reading and writing AVR of OLTC, etc. had to be made. And because some of the key personnel that developed this, stopped at Tampere University, new personnel had to fill the positions, and thereby had to do bug fixing on unknown code. This is a task that is slow.

Security measures for closed-loop testing

Demonstrating a prototype system in the real-life distribution network including customers needed much more effort than originally thought. Achieving the objectives of the project that would require a long-term and closed-loop demonstration of the automation system and functionalities. Therefore, the implementations for the demonstration were decided to include several safety and security mechanisms in addition to basic functionalities. These mechanisms are valuable outcomes of the project as such but required also extra development and testing time which was not considered in the original time schedule.

COVID-19

The COVID-19 pandemic has affected the project to some degree. Travel bans across European borders and working from home office, has led to some delays. Key personnel at Tampere University, did not have access to their own laboratory where the backup SAU was situated. Further, home office for RAH personnel meant resolving issues at the substation needed more planning than normal.

5. Project results

This section summarizes the main results of the projects. In Section 5.1 the main results are summarized in Table 3. The technological results are presented in section 5.2. Section 5.3 gives an overview of the commercial results. In section 5.4 the target group and the value added are analysed. Finally in section 5.5 the dissemination results are presented.

5.1 Overview of the results

Table 3 show an overview of the main results in the project, and in which section of the report each deliverable in details can be found.

Table 3: Overview of the results.

Objective	**Results**	**Further explanation**
Technical viability of developed substation automation solution	A successful closed-loop demonstration was realized, which proofed the capability of the solution	Chapter 5.2 Deliverables D4.1 and D.6.1
Edge computing architecture	Edge computing solution was realized and demonstrated	Chapter 5.2 and 6.1 Deliverable 4.1 and 6.1
Benefit analysis	Due to two main factors the benefit of the system has been less than expected. The demonstration grid was too strong to increase hosting capacity notably. The control bandwidth was too narrow to increase the voltage quality and decrease losses.	Chapter 5.4 Deliverable 5.2 and 6.1
Lessons learnt for commercialization	Three main architectures have been identified as potential solutions for a commercial product. However, the project's industrial partner will not develop the concept further.	Chapters 5.3 and 6.1 Deliverable 5.2

5.2 Technological results

The most important technological result was the successful demonstration of the real-life closed-loop secondary voltage control solution to proof the capabilities of automation concept, prototype implementation and functionalities. The demonstration has been run between June 1st 2021 and February 1st 2022. It verifies the capability of implemented prototype to operate autonomously without continuous monitoring or management by the operator. The solution has realized successful operation to increase hosting capacity, enhance voltage quality and reduce losses. The detailed analysis of demonstration has been realized to verify those.

The prototype implementation of substation automation solution is realizing monitoring, state estimation, optimization, and controller set-point adjustment functionalities. The cost of the solution has been minimized by utilizing only strategically most important measurements. The concept is utilizing measurements already available at the substation (demonstration was utilizing own measurements due to security reasons). In addition to those, a methodology to select the most important additional measurements and their locations was developed and utilized in the project. One additional current measurement per MV feeder was needed for secure monitoring and accurate state estimation to verify correct functioning in all parts of the grid.

In addition to real-time measurements, the state estimation was utilizing successfully load profiles, which were tailored for the customers in the demonstration area based on the latest smart meter measurements. The concept to realize the tailored load profiles was following the GDPR rules and the policies of RAH. That proved the capability to utilize sensitive customer data for load profiling by an external party when the data processor agreement and technical solutions for that are available. The automation system included aggregated load profiles to avoid the need to model low voltage networks and to enhance privacy of the solution. The state estimation and load profiling algorithms were taken from previous projects and those are described in detail in Mutanen [2]. The accuracy of the state estimation was verified by leaving out one of the real-time measurements and estimating that state. After all corrections in grid model and measurement system, the accuracy of the functionality was proofed to be satisfactory and secure for the closed-loop demonstration. An example of such verification is represented in Figure 3.

The optimization functionality was minimizing the cost function consisting of network losses, production curtailment, voltage deviation and number of tap changer operations within given network constraints and given control resources. The weights in the cost function may be adjusted according to DSO's needs and in the project, preference was given to voltage deviation. The demonstration utilized relatively tight network constraints, which did not allow wide feasible solution space for the optimization. These constraints may be relaxed, which will provide more benefits for the DSO, when the trust for the system increases. The functionality of the optimization algorithm was also taken from previous projects, and it has been presented in Kulmala [3].

The final step of the secondary control in the demonstration was the adjustment of control set-point of AVR of OLTC. The voltage reference of the AVR is adjusted to maintain optimal voltage levels in complete medium voltage network. This happens immediately after optimization, typically once a minute if adjustment is needed. The adjustment is based on reactive decision of monitoring, state estimation and optimization functionalities. This was concluded to be appropriate for vacuum type tap changers like utilized in the demonstration, because, according to MR, the incremental cost of tap changer maintenance cost due to secondary voltage control is very minimal or even non-existent. The complexity of the automation system and uncertainty of decision making would have been increased remarkably if the predictive optimization would have been applied.

The third key technological result of the project is the design of the secondary voltage control implementation. The following diagram (Figure 4) shows the ideal solution to utilize an autonomous edge computing (Substation Automation Unit, SAU) for secondary voltage control. The solution is ideal in the sense that a complete commercial control solution might be realized by integrating it as a part of a modern substation automation and control centre IT systems. In the easiest case an additional software is needed to integrate in the substation computer. Substation automation system would provide access to measurements of Intelligent Electronic Devices (IEDs) at the substation and in remote locations via SCADA. Similarly, the adjustment of control settings defined by the secondary controller would be delivered to corresponding primary controllers (AVRs in this case) via substation automation. Distribution Management System (DMS) would provide up-to-date grid model data for example when the topology of the network has changed, or a new component or customer has been added to the network. Network Information System (NIS) and Customer Information System (CIS) are added to diagram because they provide important input information for DMS to construct the grid model. Updating of the DMS topology information is based on SCADA information (e.g., status of switches), operator's actions of manually controlled switches and in some cases also based on outage alarms of smart meters via Advanced Meter Management (AMM) system. Smart meter information is collected to CIS as well for billing and customer modelling purposes to get more accurate load profiles than national load profiles typically defined many years ago with very limited amount of data. This solution has been the basis of the design for the demonstration.

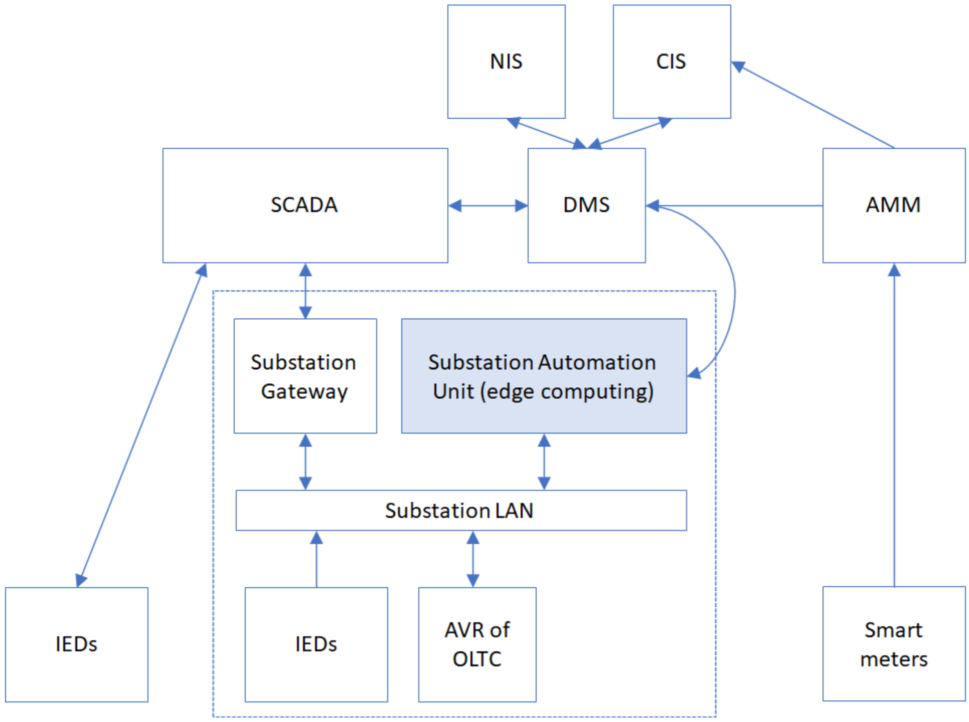

Figure 4:. Autonomous edge computing of secondary voltage control as a part of substation automation and control center IT-systems.

The implementation of automation system for the demonstration included several fail-safe features in order to guarantee secure operation of the system during disturbances and other unexpected events. Some of them were required to allow the installation of prototype devices to real-life distribution network and to realize complete closed-loop control of the system. Therefore, the demonstration included special features, which the commercial solution would never include. For example, the parallel operation of AVRs would never be needed, but that was needed to separate normal SCADA operation and the demonstration completely. The settings of AVRs needed proper settings to operate correctly during the demonstration but would keep the security and voltage quality of the distribution network at good level in all possible normal and disturbance conditions. A device called “safe mode device” was utilized to receive continues signal from SCADA to enable the demonstration. If the operator would see it necessary, he might stop the demonstration by switching off the signal. Also, the prototype did not have connection to substation LAN, and therefore a data logger and own substation measurements were built for the demonstration. All the previous features were needed only for the demonstration to increase the security. However, few safe mode operation routines were developed for the substation automation unit itself, which would be useful in commercial solution as well. These are routines to reboot individual processes or the whole computer after a crash, automatic startup of all processes and parametrized limitations and configurations for functionalities.

5.3 Commercial results

The project has succeeded to raise the technology readiness level (TRL) in European scale from TRL5 to TRL7 (partly to TRL8). The outcome of the project is a system prototype demonstration in operational environment. The demonstration is full scale in the sense that all necessary components are included, and the design and engineering is aimed to fulfil industrial relevant security requirements. The testing of the system has been realized in varying conditions of electricity network in real-life demonstration. The integration of system has been verified to be compatible with IEC 61850 MMS and CIM network model exchange. Several steps for a commercial product still exist, but those can be examined in a later commercialization project. Manufacturing, maintenance and safety or interoperability certification aspects of the control system has not been in the focus of this project.

Although, the main focus of the project was to develop and demonstrate secondary voltage control based on decentralized and autonomous edge computing architecture, main parts of the development may be utilized in centralized SCADA/DMS based systems as well. This is true especially for functionalities, engineering tools, and basic concept of secondary control. In a similar way, although the demonstration was realized in the medium voltage distribution network, there is not limitation to apply it for low voltage distribution networks as well. The concept is very interesting in the case where the distribution transformer (MV/LV) includes OLTC and the low voltage network has congestion problem due to distributed generation and/or electric vehicles.

The market for technical solutions solving congestion problems in medium and low voltage distribution networks exists especially in countries where the penetration of distributed generation, electric vehicles and heat pumps are going faster than DSO's capability to expand the distribution network. Secondly, the European directive 2019/944 and all European national legislations require that DSOs should utilize the most cost-effective network expansion method and consider so called active network management methods (for example secondary voltage control for congestion management) in addition to passive grid expansion (for example replacing existing cables which still have lifetime left with larger cables). However, in many countries the grid regulation still favours capital expenditures instead of active network management type of solutions, which typically slightly increase operational expenditures while realize a large saving in the capital expenditures. Changes are, however, expected for the grid regulation in near future to remove this barrier.

Although, the technical specification of the automation system is quite extensive, there exists always ways to learn and improve systems. Such lessons learnt was reached during this project as well.

The accurate and up-to-date network model is very important for the correct and accurate enough operation of the developed automation system and functionalities. Both the state estimation and the OPF are utilizing the network model. Verifying and correcting the network model took a very long time in the project, which is not acceptable in commercial projects. The project engineering company who is going to install the secondary voltage control system needs to have tools to verify the correctness and accuracy of the network model before starting installations and configurations of the system. Otherwise, all commercial projects will experience similar challenges, because errorfree or complete enough network models do not exist. Secondly, the performance analysis of the secondary voltage control system, especially the analysis of differences between state estimation and measurements, may indicate inaccuracies in the network model during the operation phase. This information is valuable for the DSO, because the network model will impact other functionalities and results in network operation and planning. The performance analysis may also be applied to indicate inaccurate measurements or pseudo-measurements (load profiles), which are the second source of inaccuracy in the state estimation. Inaccuracy of a load profile is typically a result of changed customer behaviour e.g., new electric vehicles, heat pumps etc., or due to change in work shifts in industry.

The network model is needed to keep up-to-date also during the whole lifetime of the secondary voltage control system. This requires automatic updating of the network model immediately when network topology changes, new customers are connected, new network sections are added or old sections removed or replaced, etc. The most efficient way is to maintain up-to-date network model in Distribution Management System and to provide CIM interface for network updates.

Due to network topology changes, the location and number of measurements should be considered in such a way that the accuracy of the state estimation functionality remains at a satisfactory level in all possible network topologies. This requirement may naturally be fulfilled by adding more real-time measurements, which however makes the system more expensive and therefore less attractive from business perspective. At least two other options exist for that purpose.

The minimum number of real-time measurements needed for the state estimation of radial distribution network is the MV substation voltage measurement and the feeder current measurements from the same substation. All other nodes might utilize pseudo-measurements, which is a common practice in networks having only demand. The accuracy of the state estimation may be improved by providing more accurate load profiles for the state estimation. In that case, one missing real-time measurement along the feeder is not so critical. Accurate load profiles may be achieved by utilizing large-scale smart metering data and advanced load profiling algorithms for correct customer classification/clustering, profiling, and consideration of external factors like outdoor temperature Mutanen [2]. Load profiles should be updated from time to time, because customers may change their behaviour, which may result in a need to change the profiling group of the customer and in the long run updating of profiles.

Near real-time measurement data from selected smart meters could provide alternative methods for real-time measurements along feeders. Smart meters are not capable enough today, but the second generation of smart metering system has been started to develop on countries which realized smart meter roll-out first and on countries which have not yet realized smart meter roll-out. The smart metering system should provide accurate enough voltage measurement in addition to power measurement, provide interface for near real-time information exchange and capability of external systems (other than meter reading systems for billing purposes) to subscribe data. The same information exchange platform might be utilized to communicate with small, distributed generators in customer premises, if they have connection to a smart meter. This would be especially important for the secondary voltage control system taking care of a low voltage network.

Of course, the smart metering system is just one possible system to receive required measurements and communication for control setting adjustments. In more general terms, the distributed architecture to connect thousands or millions of devices for DSO automation systems would be needed. Many of those devices like solar panels and electric vehicle charging points are owned by customers or service companies. The solutions for secure distributed multistakeholder architectures are still under development, but the following example would give a good hint, why those are needed.

An IoT connectivity platform is an easy way to integrate measurements and controllers outside HV/MV substation for the automation system in the demonstration. However, if every device manufacturer will add their own connectivity platform, the automation system of a DSO becomes very challenging to maintain, configure and guarantee cyber-security. Therefore, in the long-run, DSOs needs to have their own strategy for inter-substation and horizontal communication outside substations including customer connection points and even customer premises in case of reactive power or voltage control of small, distributed generators.

5.4 Target group and added value for users

The target group of the solution is DSOs. The added value of the solution is to increase the hosting capacity of a grid for renewable energy sources, electric vehicles, and heat pumps etc. At the same time, it is possible to enhance the voltage quality for all customers and to reduce losses of the distribution network. The automation solution is active network management solution to postpone investments to passive network when the existing network components have remaining lifetime, but the capacity or voltage quality is not enough due to increased number of renewables, electric vehicles, heat pumps, etc.

Hosting capacity

The main objective of the demonstration was to demonstrate the software and hardware implementations in SAU. Less focus has been on increasing the hosting capacity. Due to the very narrow bandwidth of the demonstration no notable increase in hosting capacity could be observed. Therefore, the hosting capacity calculations are based in simulations. The calculations can be found in the result deliverable D6.1.

The result of the calculation is summarized in Figure 5, where there is a potential for increasing the hosting capacity of PV production, from today’s 6,8 MVA to 20,5 MVA, with the control system in place.

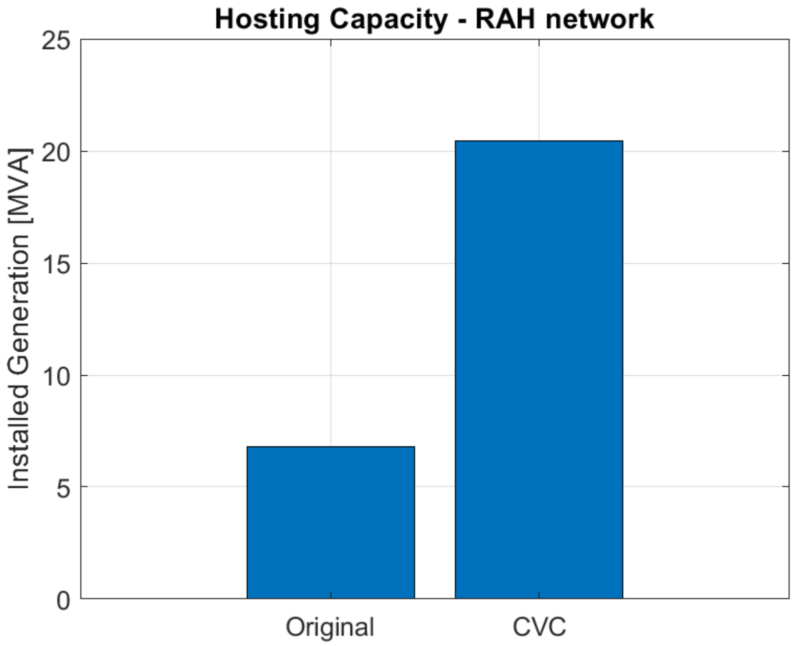

Figure 5: Result of hosting capacity calculations of solar production in the demonstration grid with and without Central Voltage Control (CVC)

Voltage quality and losses

The control bandwidth of the demonstration grid has been relatively narrow, 10,35 kV to 10,45 kV. The cost function of the OPF has had an emphasis on loss reduction. As a result, the OPF calculated that the voltage in the system optimally should be increased.

The Figure 6 below, shows the OPF result (Blue line), the Tapcon measurement (orange line) and the Tapcon setpoint (yellow line). As can be seen in Figure 6 the calculated optimal voltage in the system is approx. 10.55 kV. Therefore, the “watch dog” function in SAU, returns the setpoint at the upper bandwidth limit. The watchdog function is a script that compare the OPF result to the bandwidth. OPF results over upper limit of the bandwidth is set to the upper limit and OPF results below than the lower limit of the bandwidth is set to the bottom limit.

In the demonstration period, OPF result was in general above the upper limit of the bandwidth, and the watch-dog made sure the setpoint did not exceed the upper limit.

The result of the narrow bandwidth is that the full potential of the system could not be utilized. On the other hand, RAH’s costumers has been of highest priority, and therefore, running the system to the limits could jeopardize grid components. As one can see from the Figure 6, there are times where the optimal voltage is calculated to be over 10.7 kV, which is over what is considered safe operation of MV networks. Due to this the upper limit of the bandwidth was 10.45 kV, to ensure safe operation of the grid.

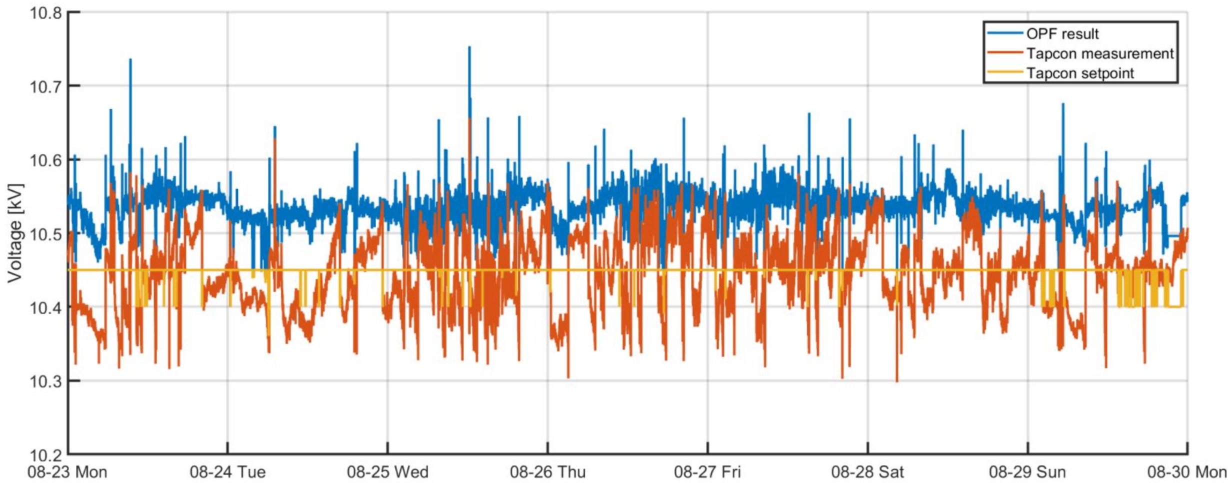

Figure 6: OPF result, TapCon measurement and TaCon setpoint. The Blue line shows the OPF result, the Orange line the Tapcon Measurement and Yellow line shows the TapCon setpoint

At the low voltage level, a small increase in voltage was seen during the demonstration. During periods with the system running the mean LV was 231,89 V and when the turned off the mean voltage was 231,31 V. Also, losses decreased slightly from the average daily loss power of 66.9 kW to 65.0 kW. This is a small change, but it is important to note that a wider bandwidth would have increased the benefit of the system. However, the main point of the demonstration has not been to go to the limits, but to demonstrate the system as concept, and that the SW/HW solution is working.

The tap operations increased from approx. 7 to 9 daily tap operations. However, since the OLTC is a vacuum type, no additional cost was introduced.

5.5 Forecasting results

The hierarchical model is implemented in the way described in Figure 7below, where Level 0 is the HV/MV transformer, Level 1 the individual feeders and Level 2 the MV/LV transformers.

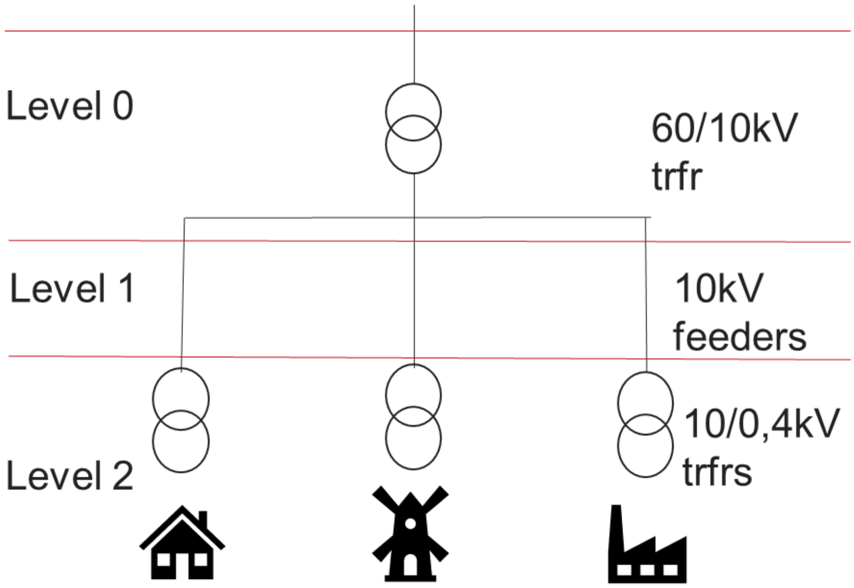

Figure 7: Illustration of the hierarchy in the model.

The below Figure 8 shows the results from the first iteration of the model. In this example, wind turbines, waterboiler, and CHP-plant is not present. The solid lines are input data and the dotted lines are the forecasts. As mentioned before the forecast time interval is 24 hours.

At level 0 the forecast is relatively acurate and is even more accurate than a Neural network model. Level 0 is used to forecast the main transformer only.

At level 2 it is apparent that the some of the substations are not capured by the model. The large unit in blue line in level 2 Figure 8 is captured as an average, but the unit itself has a very erratic pattern. To improve the overall model, this pattern can be more accuratly forecasted, and the result will be tranfered through the whole hierarchy, and thereby be more accurate at both level 1 and level 0.

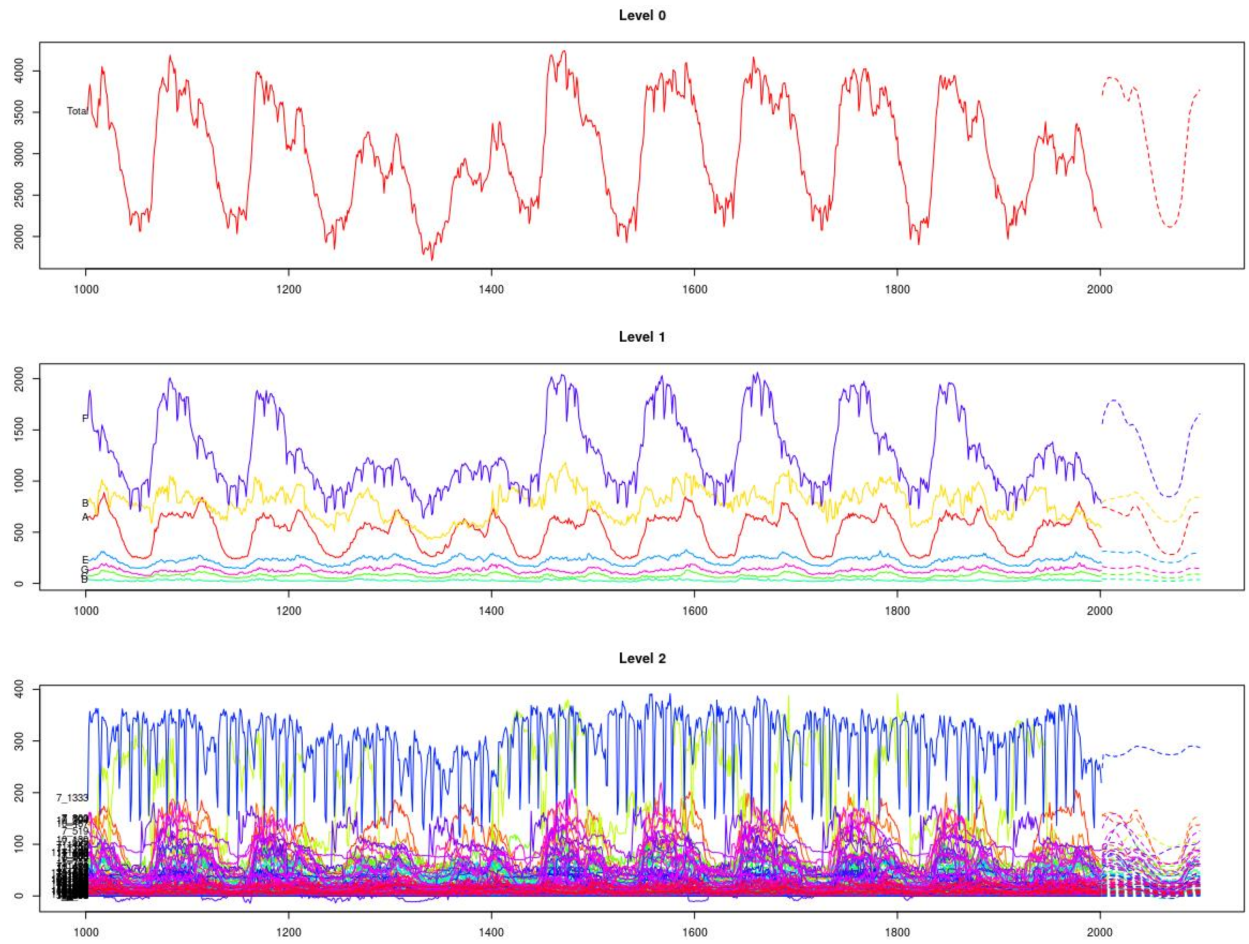

Figure 8: Forecasting results of the 3 levels.

5.6 Dissemination results

The following publications have been published based on project results. All conference publications have been presented in the corresponding conferences.

- K. Ruuth, A. Supponen, A. Mutanen, S. Repo, K. Rosenørn, M. Møller, Lessons learnt in implementation of coordinated voltage control demonstration, 26th International Conference on Electricity Distribution (CIRED), 20-23 September 2021, Geneva, Switzerland.
- S. Repo, M. Attar, A. Supponen, A. Keski-Koukkari, A. Safdarian, A. Kulmala, M. Vilkko, Coordination concepts for interactions between energy communities, markets and distribution grids, 26th International Conference on Electricity Distribution (CIRED), 20-23 September 2021, Geneva, Switzerland.
- Ruuth, K., Supponen, A., Repo, S., Rosenørn, K. R., Douglass, P., and Møller, M., "Practical Implementation of Optimal Voltage Control in Distribution Network – System Verification, Testing and Safety Precautions", 2020 IEEE PES Innovative Smart Grid Technologies Europe (ISGT-Europe), The Hague, Netherlands, 2020, pp. 1186-1190, doi: https://doi.org/10.1109/ISGT-Europe47291.2020.9248806 .
- Martinmäki, S., Repo, S., Rauma, K., Spina, A., Rehtanz, C., A robust coordinated voltage control in low voltage networks validated through an experimental study - collaboration of an on-load tap changer and a battery energy storage, CIRED workshop, June 2020. Berlin, Germany.

- S. Repo, D. Della Giustina, F. Ponci, What should be done to make revolution in smart distribution grids?, 25th International Conference on Electricity Distribution (CIRED), 3-6 June 2019, Madrid, Spain. https://www.cired-repository.org/handle/20.500.12455/586
- A. Mutanen, P. Järventausta, S. Repo, Smart Meter Data-Based Load Profiles and Their Effect on Distribution System State Estimation Accuracy, International Review of Electrical Engineering (2018), https://doi.org/10.15866/iree.v12i6.13419
- Supponen A., Kulmala A., Repo S., Coordinated Voltage Control as a Replacement for Passive Network Reinforcements - a Case Study, IEEE International Conference on Smart Grid Communications 23-26 October 2017, Dresden, Germany.

The following news stories have been published about the project. The stories are published to Dansk Energi's website and spread through linkedin.com. The latter news story got more than 2000 views.

- Tornbjerg, J., 2018, *Data om skyer skal optimere drift af elnet*, Dansk Energi, Accessed 28-09-2021, <https://www.danskenergi.dk/nyheder/teknik/data-om-skyer-skal-optimere-drift-elnet>
- Tornbjerg, J., 2021, *Smart udstyr styrer spændingen i Ringkøbing,* Dansk Energi, Accessed 28-09-2021, <https://www.danskenergi.dk/nyheder/smart-udstyr-styrer-spaendingen-ringkoebing>

Other dissemination:

- Keynote: Frontiers in Autonomous Systems, Conference November 25th 2021, Technical University of Denmark, DTU Centre for Collaborative Autonomous Systems
- OVR project as example on forecasting in the energy systems. Online workshop on energy sector unbundling in South Africa.December 12th 2021
- Three annual events for first year students at Technical University of Denmark, DTU. OVR project has been used as an example on what Dansk Energi is working on. November 6th 2019, November 6th 2020 and November 3rd 2021.

6. Utilisation of project results

The substation automation unit (the edge computing solution, SAU) is the primary result of the project. The prototype of the substation automation unit has been utilized in the demonstration and therefore it has already proved its capability. However, it is not yet ready for a commercialization project. Several important features listed in Chapter 8 are still missing, and therefore an improved prototype is required to develop and demonstrate before full-scale commercialization project.

The functionalities further developed in the project begins to become ready for commercial usage. Those are generic enough to be applied in edge computing, and in control centre level IT systems. State estimation and OPF are CIM-compliant in terms of grid modelling, but algorithms does not have certificate about that because the testing has been realized only for project purposes. CIM-compliance enables to utilize them as a part of service-oriented control centre IT system as an independent software module.

The SAU may also host many additional functionalities to be developed in the future research projects utilizing real-time substation or field measurements. The prototype device would also perform as a real-life platform for a research project.

Safety and security mechanisms developed for the substation automation solution may also be utilized in the future demonstration and commercialization projects. If those may not be utilized as such, at least the experience of developing and utilizing those is a valuable knowledge.

6.1 Commercial results

The project has identified three possible architectures for a marketable solution: Edge computing, cloud-based solution, and SCADA-integrated solution. These are described in dept in deliverable 5.2, and only given a brief introduction in the next sections.

Edge computing architecture:

The edge computing architecture is a centralized control, monitoring and protection unit, just as the system demonstrated in the project. The architecture is illustrated in Figure 9 and shows individual SAU machines at individual substations with communication between SAUs. With this solution there is a need for more hardware at site and therefore this solution usually is more suitable for smaller scale systems, as large-scale implementations need more powerful computation resources.

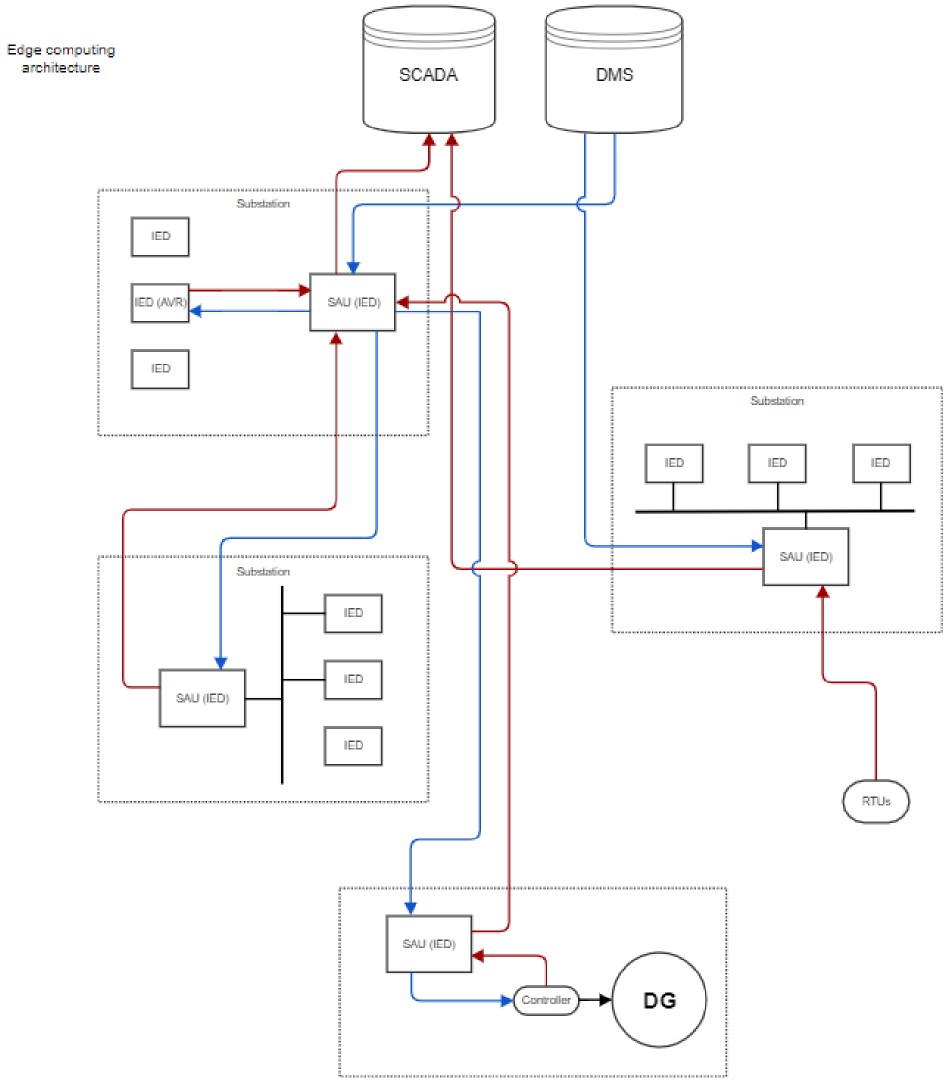

Figure 9: Principal overview of the edge computing architecture.

Cloud computing architecture:

The cloud computing architecture (Figure 10) utilizes a decentralized cloud solution for running algorithms and communication. This means that there is no need for extensive computational power and hardware at the site. On the other hand, latency could be a problem, therefore this solution is not always suitable for time-critical applications. Another issue can arise if information and algorithms are in the cloud: What happens when there is no network connection? In this case, the intelligent control will be lost if the network connection is lost, or the cloud service is offline.

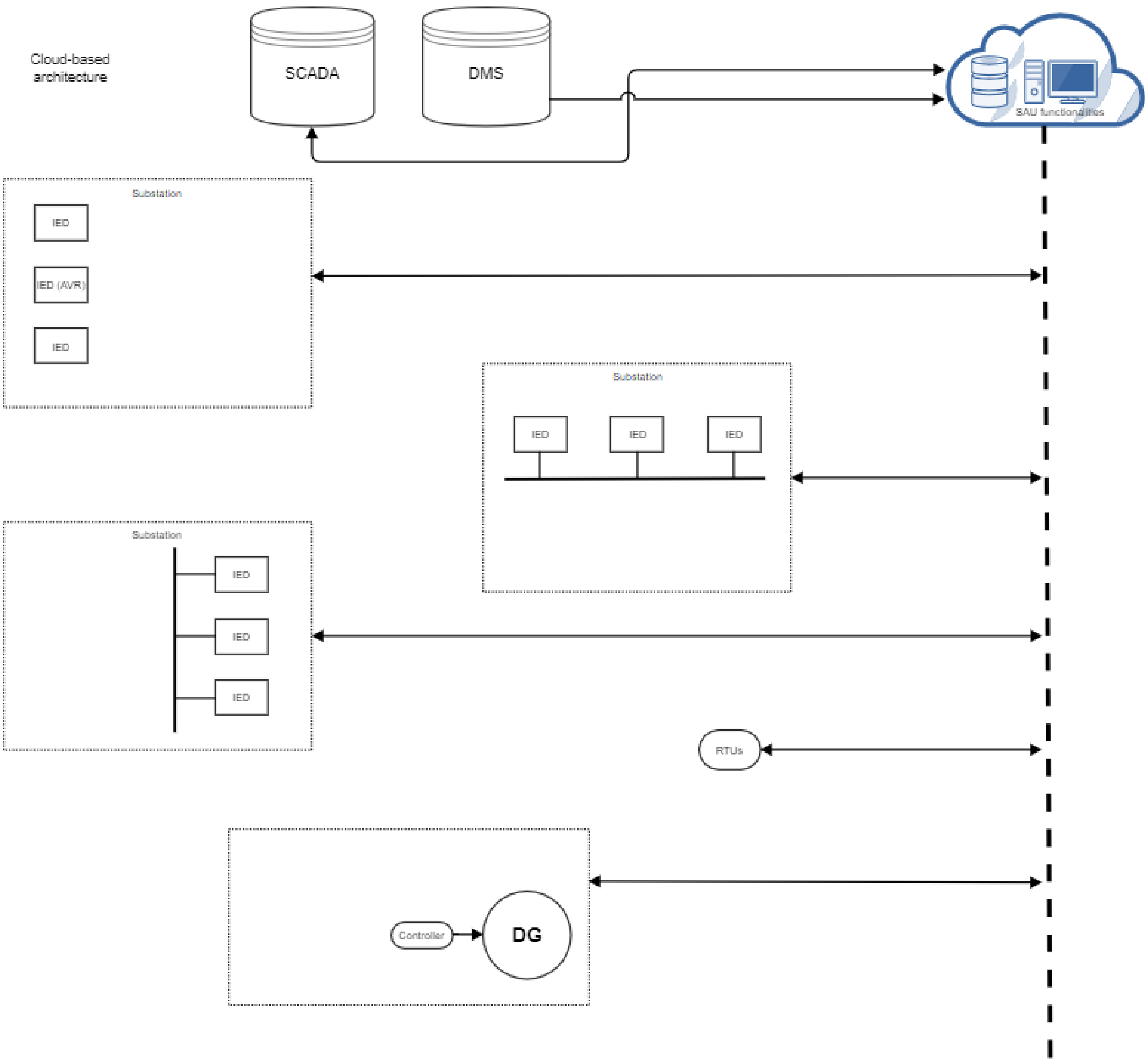

Figure 10: Principal overview of the cloud-based architecture.

SCADA integrated architecture:

The SCADA integrated architecture (Figure 1Figure 11) utilizes the existing SCADA system, and all computation is done within SCADA. In this case communication can be a problem e.g., with DNP3 protocols, transfer of large amounts of data is impossible, as these protocols are designed to provide fast and lightweight communication of control and status information to system operators and are not designed for transferring the amount of data needed to operate secondary voltage control. The DNP3 protocol is designed for small communication packages may not be suitable when the information and especially the size of the multipoint communication messages are rapidly increasing.

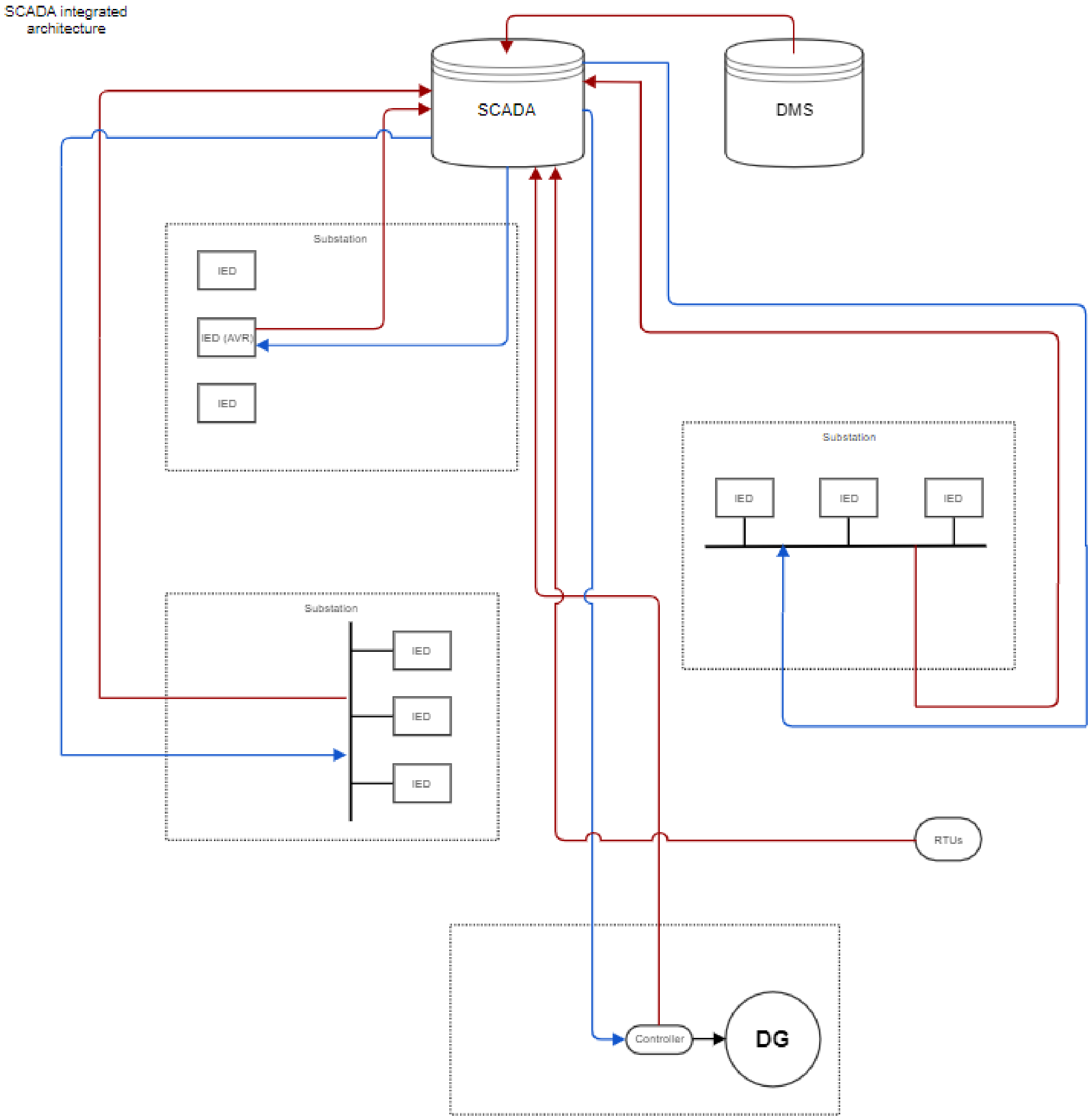

Figure 11: Principal overview of the SCADA-integrated architecture.

Best solution for near future implementation

All the above architecture has both pros and cons. The most realistic near future solution would be an edge-cloud solution. This combines the edge and cloud-based solutions and is probably the most integrable solution. An edge-cloud computing architecture would have a part of the computation done in close proximity to end devices in the grid and a part in the cloud where major part of data would be stored. By moving part of the computation and storage resources to the edge, the network performance gain can be significant. Therefore, from the Technology Readiness Level (TRL) perspective edge-computing or edge-cloud computing architecture are the most promising options for near-future product commercialization. The applicability and security policies concerning third-party products in smart grid automation solutions is the obstructive factor for near-future installations. However, this is also about to change with the future where prosumers, microgrids, IoT-devices etc. are widespread and Active Network Management (ANM) is utilizing its full potential.

Lessons learnt

The accurate and up-to-date network model is very important for the correct and satisfactory operation of the developed automation system and functionalities. Both the state estimation and the OPF are utilizing the network model. Verifying and correcting the network model took a very long time in the project, which is not acceptable in the commercial projects. The project engineering company who is going to install the secondary voltage control system needs to have tools to verify the correctness and accuracy of the network model before starting installations and configurations of the system. Otherwise, all commercial projects will experience similar challenges because errorfree network models do not exist. Secondly, the performance analysis of the secondary voltage control system, especially the analysis of differences between state estimation and measurements, may indicate inaccuracies in the network model during the operation phase. This information is valuable for the DSO, because the network model will impact other functionalities and results in network operation and planning. The performance analysis may also be applied to indicate inaccurate measurements or pseudo-measurements (load profiles), which are the second source of inaccuracy in the state estimation. Inaccuracy of a load profile is typically a result of changed customer behaviour e.g., of new electric vehicles or heat pumps, or due to change in work shifts in industry.

The network model is needed to keep up to date also during the whole lifetime of the secondary voltage control system. This requires automatic updating of the network model immediately when network topology changes, new customers are connected, new network sections are added or old sections removed or replaced, etc. The most efficient way is to maintain up-to-date network model in Distribution Management System and to provide CIM interface for network updates.

Due to network topology changes, the location and number of measurements should be considered in such a way that the accuracy of the state estimation functionality remains on a satisfactory level in all possible network topologies. This requirement may naturally be fulfilled by adding more real-time measurements, which however makes the system more expensive and therefore less attractive from business perspective. At least two other options exist for that purpose.

The minimum number of real-time measurements needed for the state estimation of radial distribution network is the MV substation voltage measurement and the feeder current measurements from the same substation. All other nodes might utilize pseudo-measurements, which is a common practice in networks having only demand. The accuracy of the state estimation may be improved by providing more accurate load profiles for the state estimation. In that case, one missing real-time measurement along the feeder is not so critical. Accurate load profiles may be achieved by utilizing large-scale smart metering data and advanced load profiling algorithms for correct customer classification/clustering, profiling, and consideration of external factors like outdoor temperature [2]. Load profiles should be updated time to time, because customers may change their behaviour, which result in a need to change the profiling group of the customer and in the long run updating of profiles.

Near real-time measurement data from selected smart meters could provide alternative method for real-time measurements along feeders. Most of today's smart meters are not capable of delivering near real-time data, however the second generation of smart meters, which could provide near real-time measurements, has started to be rolled out in countries that realized smart meter roll-out first and in countries which have not yet realized smart meter roll-out. The smart metering system should provide accurate enough voltage measurement in addition to power measurement, provide interface for near real-time information exchange and capability of external systems (other than meter reading systems for billing purposes) to subscribe data. The same information exchange platform might be utilized to communicate with small, distributed generators in customer premises, if they have connection to a smart meter. This would be especially important for the secondary voltage control systems taking care of low voltage networks.

IoT connectivity platform is an easy way to integrate measurements and controllers outside HV/MV substation for the automation system in the demonstration. However, if every supplier will add their own connectivity platform, the automation system of DSO as a whole becomes very challenging to maintain, configure and guarantee cyber-security. Therefore, in the long-run, DSOs needs to have a strategy for inter-substation and horizontal communication outside substations including customer connection points and even customer premises in case of reactive power or voltage control of small, distributed generators.

6.2 Target group and added value for users

The target group of the results are DSOs who experience congestion challenges in their distribution network, which still has useful life-time left before rebuilding the grid infrastructure for that area. The demonstrated solution may in some cases increase the hosting capacity of the grid for renewable energy sources, electric vehicles, and heat pumps. The financial saving of the solution is remarkable when the grid investments may be postponed. Also, the amount of production curtailment may be reduced or avoided, which would benefit both the DSOs and the producers. The same solution may be utilized to enhance voltage quality and to reduce grid losses when the control system is not needed for the enhancement of hosting capacity.

6.3 Dissemination results

In general, the dissemination regarding the project is summarized in section 5.5. The final calculations of hosting capacity, losses and voltage quality has not been ready for presentation before the very end of the project, and therefore has not been disseminated. However, preliminary results about the demonstration have been disseminated at several times.

- Keynote: Frontiers in Autonomous Systems, Conference November 25th 2021, Technical University of Denmark, DTU Centre for Collaborative Autonomous Systems
- OVR project as example on forecasting in the energy systems. Online workshop on energy sector unbundling in South Africa.December 12th 2021
- Three annual events for first year students at Technical University of Denmark, DTU. OVR project has been used as an example on what Dansk Energi is working on. November 6th 2019, November 6th 2020 and November 3rd 2021.
- Tampere University have several publications planned, for when all the data is analyzed. This is work in progress and will be published after the project has ended.

7. Utilisation of project results

Technical results

Tampere University will utilize the prototype in a future research project as a background for the further development. The existing prototype solution will be further developed by adding features listed in Chapter 8. Also, additional functionalities utilizing the developed edge computing platform will be developed to increase the interest of the proposed concept among DSOs and automation manufactures. One such project is on-going as the Academy of Finland has funded a research project called “Distributed management of electricity system”.

Open-source publishing of developed algorithms, software and designs will be investigated in the near future. This would enable to utilize and further develop those elements by other researchers and pilots.

Commercial results

The project was not aiming for a commercial solution. Therefore, the utilization of results will not increase turnover in near future.

Competition situation

Some SCADA/DMS providers have similar functionalities, which would compete in medium voltage networks. However, those are aimed to utilize for large-scale control resources, while the edge computing solution is aimed to integrate any number of measurements and control resources including small-scale photovoltaics, electric vehicles, and heat pumps if needed and available for the optimal voltage control.

In some specific case tailored microgrids might compete in low voltage networks. However, the main target of the developed solution is to enhance voltage control of medium voltage network in combination with low voltage networks. Therefore, typical microgrids are not exactly competing with the developed solution. The reason to invest in a microgrid is very much different than distribution network management.

Also, some individual hardware solutions like voltage boosters, line voltage regulators, or OLTC in distribution transformers will compete with the proposed solution especially if the problematic voltage area is limited to very specific grid area.

But the passive network is the hardest competitor. DSOs needs to be “educated” first to accept the idea of active network management. The resistance of change is very natural, because the new technology is always a risk for an infrastructure and will take a lot of time to learn to utilize it in optimal way. Important is therefore to find the cases where the proposed solution will bring the highest benefits for DSOs, and to convince them in this way. Creating a trust for the concept, technology and providers are the key essentials for a successful commercialization. This has become very clear also during the demonstration project as well.

Barriers

In most European countries, grid regulation favours passive grid investments compared to active network management solutions. Therefore, the business case must be very strong to provide enough benefits for the developed solution. The solution may not become the mainstream technical solution for the congestion problems before grid regulation is changed like explained in Chapter 5.3.

The second barrier is the tradition and knowledge of DSOs to build passive distribution networks. The knowledge to utilize and build active distribution networks is slowly spreading.

Especially a start-up company requires a commercial demonstration case to proof the technical and commercial capabilities. Conservative business domain, however, favours traditional manufactures.

Energy policy objectives

The Danish government has committed to a 70% reduction in climate gas emissions by 2030, compared to 1990 levels. To reach this goal, electrification of heat and transportation is key elements in the green shift. At the moment, the political goal is such, that by 2030, there are at least 750.000 EVs on Danish roads, and recent sales statistics shows a path towards at least 1 million EVs in 2030, this can be seen in Figure 12.

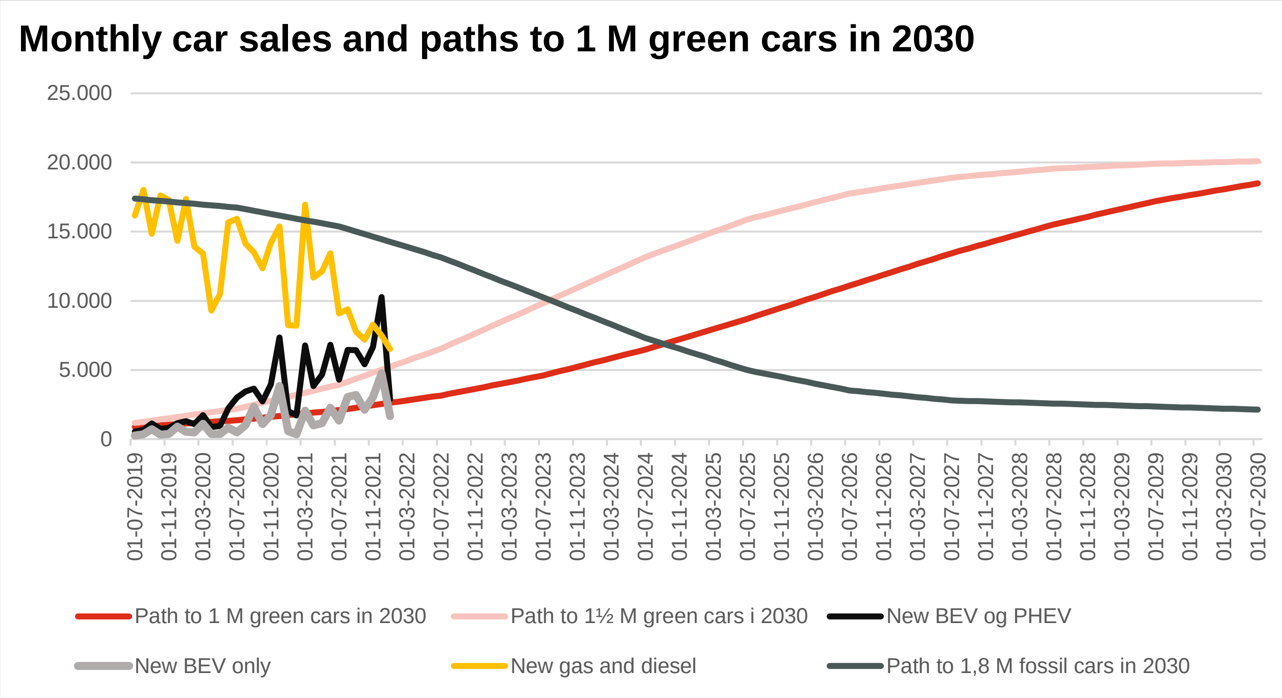

Figure 12:Monthly car sales in Denmark and paths to realisation of politacal goals for electrificaiton of the private transport sector

Reaching this commitment, will need a significant number of DKK billions of investments in the electrical grid[2]. It is expected that especially MV networks will be challenged in the short term towards 2030. Thereby, increasing hosting capacity in MV networks will be very beneficial in reaching the 2030 goals. An increase in hosting capacity will directly translate into a reduction of the cost of grid integration of renewables, electric vehicles and heat pumps. If the DSOs can postpone investments and enhance the utilization of existing components, it will potentially give the DSOs a better overview of the development in grid utilization and thereby be able to invest on informed basis and reduce risk of investing incorrectly.

Further, the control system developed in the OVR-project is designed in such a way that the system's modular nature, can easily be extended to deliver other services as well. With little effort the system will be able to dispatch flexibility services as well as active and reactive power control of DERs, which has a potential for further investment reductions. However, as mentioned earlier, the Danish benchmark regulation do not accommodate investments in technology, as investments in cables and other assets are favoured in the benchmark model.

[2] I mål med den grønne omstilling 2030 | Dansk Energi

Teaching and dissemination activities

The project is strongly based on two PhD thesis realized in Tampere University within other research projects:

- Antti Mutanen, "Improving electricity distribution system state estimation with AMR-based load profiles", 2018, http://urn.fi/URN:ISBN:978-952-15-4105-6
- Anna Kulmala, "Active voltage control in distribution networks including distributed energy resources", 2014, http://urn.fi/URN:ISBN:978-952-15-3284-9

On-going PhD work is Kalle Ruuth's thesis "Developing testing methods for future energy systems: promoting the integration of renewable energy sources in the smart grid". This project has provided an excellent case study for the thesis to enhance testing methods. Many results of the project will be an essential part of the thesis.

The results of the project are utilized in MSc level courses "Distribution automation" and "Distributed energy resources in the electricity networks" at Tampere University. The results have been utilized also at PhD course "Decentralized distribution network automation for active network management" organized at Tampere University, Technical University of Denmark and University Carlos III of Madrid.

8. Project conclusion and perspective

The project was able to successfully demonstrate the capabilities of the developed substation automation solution and its optimal secondary voltage control functionality for the congestion management of medium voltage distribution networks. The demonstration was realized as a closed-loop demonstration in real-life distribution network of RAH Net A/S. The demonstration results proofed the capability of the developed solution to enhance distribution network hosting capacity, enhance voltage quality, reduce network losses, and reduce production curtailment.

The developed edge computing solution was capable for autonomous optimal voltage control based on state estimation and few strategically selected real-time measurements. The demonstration included only one primary voltage controller (AVR of OLTC of HV/MV transformer), but any number of primary controllers may be incorporated in voltage optimization. The cost function of the OPF algorithm may be parametrized to provide required priority of the optimization targets (hosting capacity, voltage quality, grid losses and production curtailment). The number of tap change operations does not have practical importance in the optimization, if the vacuum type OLTC is applied. The benefit of state estimation is to reduce the amount of required real-time measurements (cost of measurements) and to reduce the vulnerability of misleading control decision due to incorrect or missing measurement.

Next steps to enhance the prototype are to include following capabilities:

- Automated network model update in substation automation unit
- Full integration to substation automation
- Horizontal communication to measurement devices (secondary substation automation, smart meters)
- Horizontal communication to external parties like production units and electric vehicle charging points
- Integration of local flexibility market as a part of the solution
- Study if the SQL database should be replaced with non-SQL database (e.g. MongoDB)
- Marketing tool to pre-evaluate the benefits of the solution in a specific case
- Develop service agreement with DSOs based on achieved benefits (idea is to sell hosting capacity and not the technology itself)
- Develop additional functionalities based on collected measurement, estimation, and optimization data

The project has proofed that the basic concept and the automation solution are functioning and capable of autonomous operation without operators' continuous attention and to produce benefits for the DSO. Additional features to automation system and functionalities listed above should be added to make the solution attractive enough for DSOs.

9. References

[1] K. Ruuth, A. Supponen, A. Mutanen, S. Repo, K. Rosenørn, M. Møller, Lessons learnt in implementation of coordinated voltage control demonstration, 26th International Conference on Electricity Distribution (CIRED), 20-23 September 2021, Geneva, Switzerland.

[2] Antti Mutanen, "Improving electricity distribution system state estimation with AMR-based load profiles", 2018, http://urn.fi/URN:ISBN:978-952-15-4105-6

[3] Anna Kulmala, "Active voltage control in distribution networks including distributed energy resources", 2014, http://urn.fi/URN:ISBN:978-952-15-3284-9

10. Appendices

Project website: www.optimalvoltage.com

10.1 Forecasting algorithm

Model description

This section describes the forecasting system and model that was developed in the project. The original idea of the forecasting algorithm was to only forecast the main transformer in the network. This was done using Neural Network-algorithms outlined in the State of the art. However, as the project moved forward, the scope of the forecasting was changed, and instead of forecasting the main transformer only, a larger proportion of the network was to be forecasted, included secondary substations. The idea is to forecast all 10/0,4 kV transformers in the network, the cables, and the main transformer.

Hierarchical Forecasting Model

The below Figure 13 outlines the structure of a general hierarchical forecasting model. Here illustrated with three levels.

In a Hierarchical Forecasting Model, the forecasts can be done in a bottom-up, top-down or a combination of the two. In the right-hand Figure 14, the structure of the electrical grid is illustrated. As apparent in the schematic outline, the structure is in both cases are basically the same. Which is promising for using this kind of model for forecasting different parts of the network.

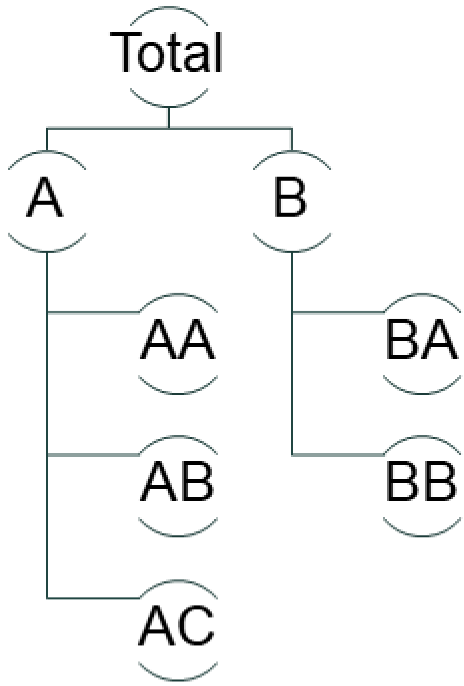

Figure 13:The hierarchical forecasting model with 3 levels

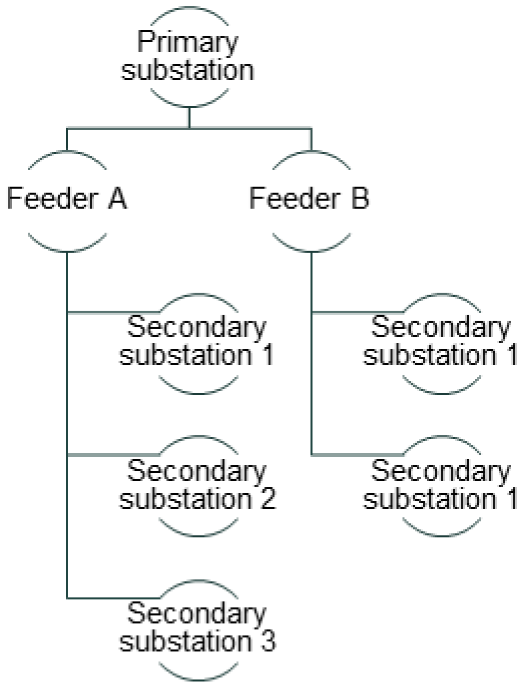

Figure 14: The hierarchical forecasting model translated to the MV grid

A strong point in utilizing this model is that different points in the hierarchy can utilize different forecasting models. As an example, the grid shown in Figure 7 with one primary substation, three feeders and three secondary substations, the forecast for the households, can be based on one model (e.g., ARIMA), the wind turbine another (e.g., Neural Networks) and the industry a third model (e.g., Linear regression). This adds flexibility to the model, as one can choose the most appropriate model for the component that are being forecasted.

Challenges

The demonstration site is situated in Ringkøbing, Jutland, and is connected to the continental European synchronous area. The Danish grid is connected to the German grid at the 400kV and 220 kV level.

The German grid has a challenge with bottlenecks, and RES-production in the northern part of Germany cannot be transported to large loads in the southern parts of the country. For the TSO to be able to handle the bottlenecks, they buy balancing power in Denmark. This is organized through a special regulation market, which is a closed market, with very little transparency. The availability of data from activations of the balancing power is not present.

This poses a challenge for forecasting some of the large units in the demonstration grid, namely the water boiler, the CHP plant, and the wind turbines, which in total can have a 27MW of production and 12MW of consumption in the RAH network area.

In the below Figure 15, this problem is illustrated. The sum of the power output from wind turbines is plotted for about one week. At the end of the period the wind conditions were ideal for wind production and consequently the turbines are producing at maximum. However, as the wind turbines are participating in the special regulation market, as the production suddenly drops, even though it is close to ideal wind conditions. This behavior is hard to forecast when the need for regulating power is unknown. The same applies to the water boiler and CHP-plant.

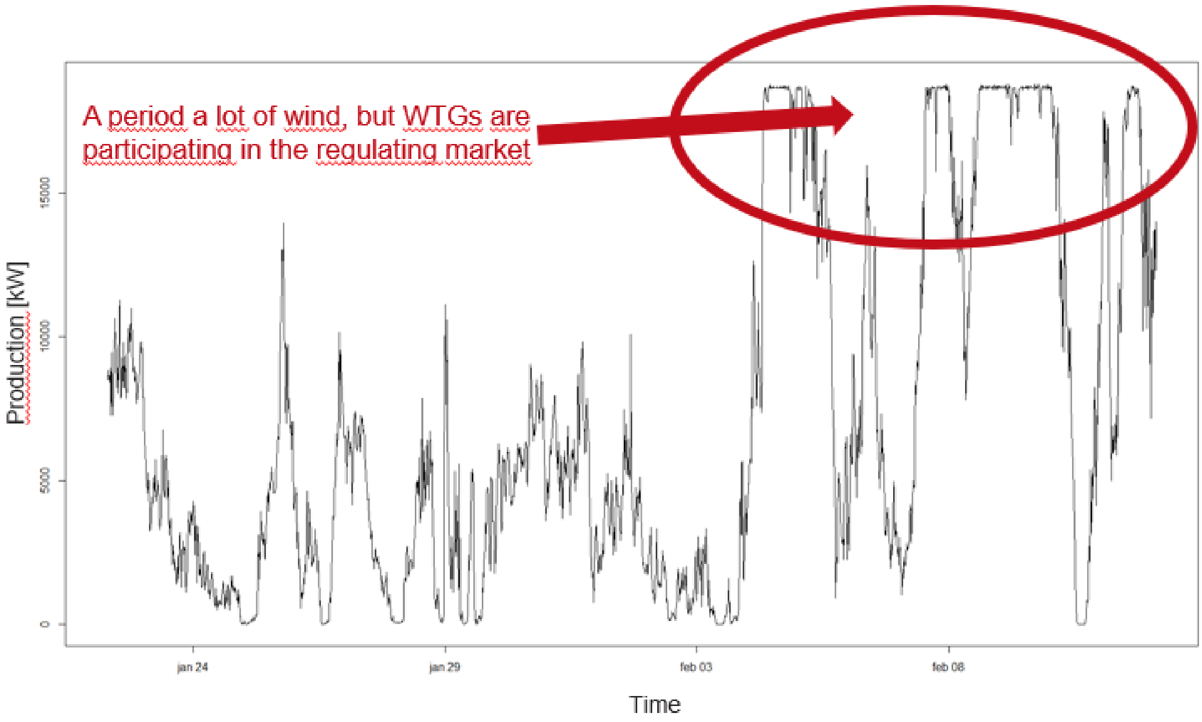

Figure 15: Wind turbine production. With periods with very good wind conditions and no production.

Implementation of the forecasting algorithm

Fejl! Henvisningskilde ikke fundet. below shows the physical implementation of the forecasting system and all its components.

- **Virtual machine (VM):** This is a small cloud computer set up to do several tasks. Once a day the machine fetches new smart meter data from the sFTP-server and reorganizes data to a database friendly format. The data is sent to the SQL-database. Every minute the VM fetch data from the weather station, arrange and upload the data to the SQL-server. Once a day the VM fetch the latest weather forecasts from Meteoblue and upload the weather data to the SQL-server. When daily weather forecasts and smart meter data has been processed and uploaded to the SQL-server, the VM sends a start signal to the OVR-forecaster machine.
- **Offline Model tuning:** To be compliant the GDPR legislation, Dansk Energi have a designated desktop computer, that is used for offline model tuning. This computer has an encrypted disk that data is stored on.
- **Daily operation:** The forecasting system is a system of several sFTP-servers, SQL-databases, VM-machines, and input variables.
- **sFTP-server:** For RAH to send metering data, a sFTP-server was set up. Smart meter data is sent to the server once every morning reporting the last 24 hours of electricity consumption for all costumers in the grid. As mentioned above, the VM downloads and processes the incoming data.
- **OVR-forecaster:** This is a powerful VM, that is powerful enough to run the forecasting scripts.
- **SQL-database:** Incoming data from the VM is sent an SQL-database and stored for use by the OVR-forecaster.

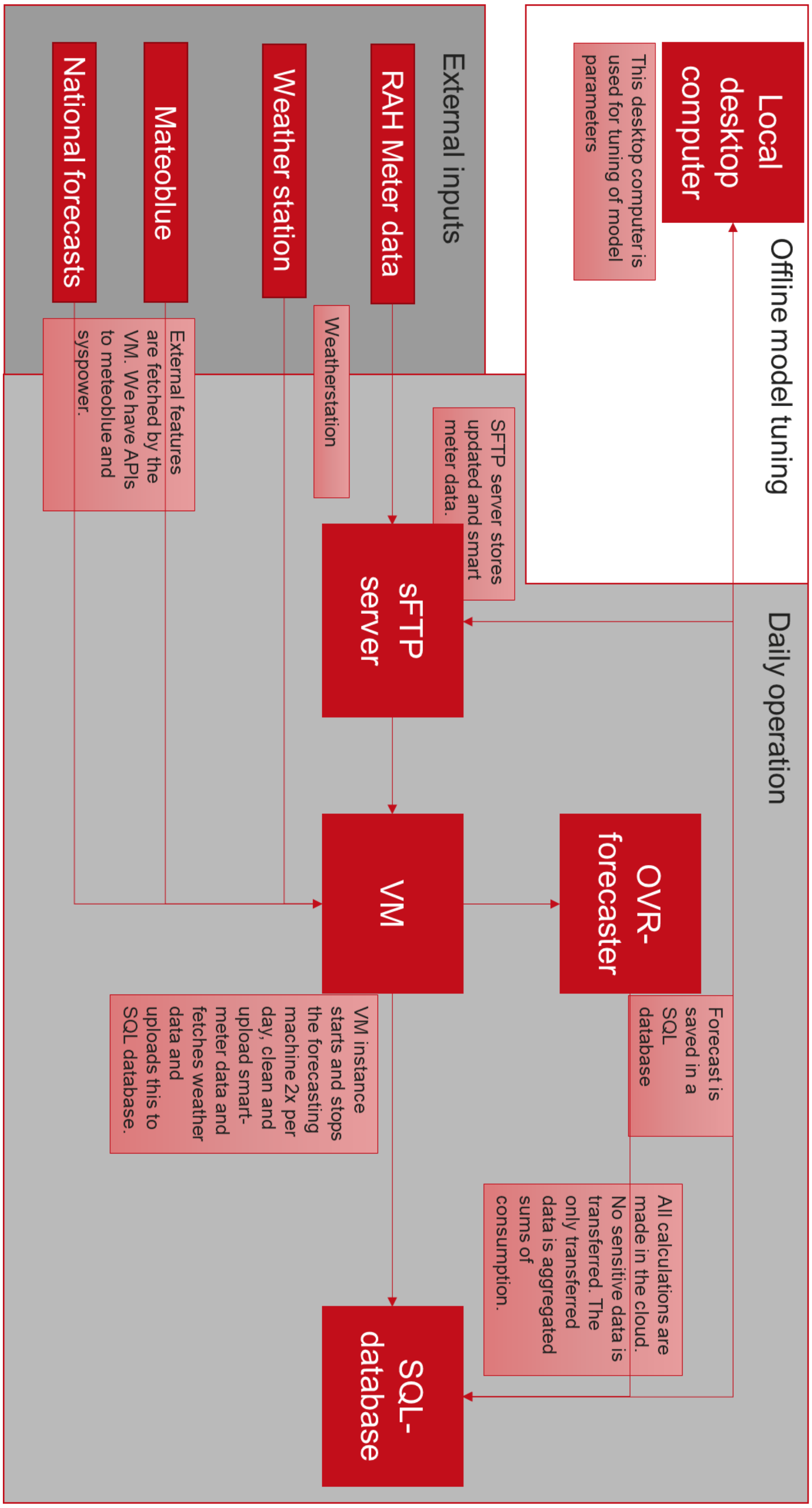

Figure 16: The architecture of the developed system.