D4.9 Bornholm Lighthouse UC-5 report

Zepter, Jan Martin Wilhelm; Ledro, Mirko; Engelhardt, Jan; Gabderakhmanova, Tatiana; Marinelli, Mattia; Poulsen, Anna Sofie; Ipsen, Hans Henrik; Jørgensen, Torben

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WP4 – Modelling, simulation, engineering, and equipment development for the Lighthouse demonstration

INSULAE
Maximizing the impact of innovative energy approaches in the EU islands

Prepared by
Jan Martin Zepter, Mirko Ledro, Jan Engelhardt, Tatiana Gabderakhmanova, Mattia Marinelli (DTU – Technical University of Denmark), Anna Sofie Poulsen, Hans Henrik Ipsen, Torben Jørgensen (BEOF – Bornholm Energi og Forsyning)

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ABBREVIATIONS

BESS	Battery energy storage system
BESSM	Bornholm Energy System Simulation Model
BMS	Battery management system
CHP	Combined heat and power
CH_4	Methane
CO_2	Carbon dioxide
CV	Coefficient of variation
DH	District heating
DHN	District heating network
DHP	District heating plant
DSO	Distribution system operator
EMC	Energy management controller
EMS	Energy management system
EV	Electric vehicle
FA	Fleet aggregator
FEC	Full equivalent cycles
HPP	Hybrid power plant
H_2	Hydrogen
KPI	Key performance indicators
MAE	Mean absolute error
MeOH	Methanol
MPPT	Maximum power point tracking
MSDS	Material safety data sheet
PSC	Power Smoothing Controller
PV	Photovoltaic
RES	Renewable energy sources
SNG	Synthetic natural gas
SOC	State-of-charge
V2G	Vehicle-to-grid
VPP	Virtual power plant
WF	Wind farm
WT	Wind turbine

EXECUTIVE SUMMARY

Deliverable 4.9 focuses on the main conclusions reached after finalizing modelling, basic and detail engineering, and equipment development activities previous to the deployment of the Use Case 5. Use Case 5 aims at assessing the integrated management of local bio-based economies supporting the electrical, thermal and transport domains at the Aakirkeby substation in the Danish Island of Bornholm.

Starting from D4.10 (Bornholm Lighthouse energy system models) and D4.11 (Bornholm Lighthouse interventions equipment detail engineering), the current deliverable D4.9 collects an extensive set of results based on data-driven simulations on the Aakirkeby virtual power plant (VPP).

Using the Bornholm energy system simulation model, different interventions are examined in close detail that form a solid base for the next step of expanding the VPP insights from the substation of Aakirkeby to the whole energy system of Bornholm and producing an action plan together with the Investment Planning Tool developed in the INSULAE project.

In this document, the reader will find an extensive description of the existing and future connected components in the VPP, comprising a biogas plant, two large-scale wind farms, a large-scale PV park, a prospective electric vehicle (EV) fleet, an electric boiler and a connected district heating network, residential and industrial consumption, as well as a prospective stationary battery and an electrolyser system. Furthermore, a set of different simulation studies are presented touching upon topics around the (i) flexibility of biogas plants, (ii) power and energy management of EV fleets, (iii) power capping capabilities of wind farms, (iv) extension of a multi-domain VPP structure by an electrolyser, as well as (v) yearly energy considerations of different interventions at the substation of Aakirkeby. This document gathers the key results of these simulation studies.

Results collected in this deliverable are based on scientific papers generated as part of the Insulae project and master thesis projects conducted at the Technical University of Denmark

D4.9 concludes, together with D4.8 (Bornholm Lighthouse Use Case-4 report), the simulation activities in the task T4.3 (Bornholm Lighthouse demonstration preparatory activities) of the INSULAE project.

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1 INTRODUCTION

The deliverable D4.9 gathers an extensive set of key results and conclusions of the performed simulation studies in the context of the Use Case 5 (UC-5) in the INSULAE project. The presented studies build upon previous investigations conducted in the beginning of the project [1]. UC-5 aims at assessing the integrated management of local bio-based economies in supporting the electrical, thermal and transportation domains at the Aakirkeby substation on the Danish Island of Bornholm. The island serves here as demo for multi-energy systems [2], [3]. The focus of UC-5 lies in the development of a virtual power plant (VPP) for exploiting the flexibility potential of existing and prospective renewable-based components. To this end, different simulation-based investigations have been performed to prepare for the upcoming demonstration activities, starting in Autumn 2021 and taking place until 2023. In detail, this deliverable gathers the results obtained on the following topics revolving around the renewable-based VPP structure:

1. The local biogas plant is characterized, modelled, and empirically validated against historical on-site measurements. The explicit representation of the plant's processes allows for the analysis of flexibility potentials as support towards a bio-based economy. The plant's potential for the provision of frequency control on the island is studied, both in terms of technical and economic feasibility.
2. The key results of power and energy management for the prospective integration of an EV fleet are presented considering EV users' behaviour. To perform a proper EV fleet management at the Aakirkeby substation, different smart charging strategies are proposed.
3. Wind power capping capabilities are studied by modelling the transient behaviour of the wind turbines in the Kalby wind farm. To this end, an academic wind turbine model has been adapted to represent the 2 MW turbines.
4. The potential for an extension of the current VPP structure for green hydrogen production is studied in a techno-economic optimisation framework. The goal of this work is to optimally size an electrolyser at the biogas plant's site. Subsequently, the production potential of alternative fuels for transportation purposes on the island is examined.
5. The impact of different interventions in the VPP Aakirkeby is examined in the Bornholm Energy System Simulation Model (BESSM) from the local distribution system operator (DSO) BEOF. Results of one-year simulations are described, showing a way for an increased decarbonization of the island.

The deliverable is structured in two parts: first, relevant data and background information is provided that serve as foundation for the simulation studies; second, the key results of the performed investigations are outlined. The learnings from UC-5 concentrates on the substation of Aakirkeby will be taken as a basis for upscaling to the whole island's perspective and contributing to the investment planning tool of the project. Some of the here described results are based on publicly available scientific articles as well as Master thesis projects at the Technical University of Denmark. Key results connected to the Use Case 4 (UC-4) of the project are reported in [4].

2 DESCRIPTION OF THE VIRTUAL POWER PLANT STRUCTURE

The studied virtual power plant (VPP) structure is based on the 60/10 kV Aakirkeby substation in the Danish Island of Bornholm [5]. Figure 1 presents the single-line diagram of the investigated VPP including its control architecture. The VPP integrates several electrical generation and consumption feeders, connected on the 10 kV side of the substation, namely a biogas plant, an electric boiler, two large-scale wind farms, a photovoltaic (PV) park, a stationary battery energy storage system (BESS), household consumption, and a fictitious electric vehicle (EV) fleet feeder. The latter represents a prospective amount of EVs in the city of Aakirkeby which is likely to happen in the upcoming years. The substation also comprises a designated heat plant running on woodchips as well as a hot water storage tank, both connected to the district heating network (DHN). The following subsections describe the required data and background information for the subsequent presentation of the simulation studies.

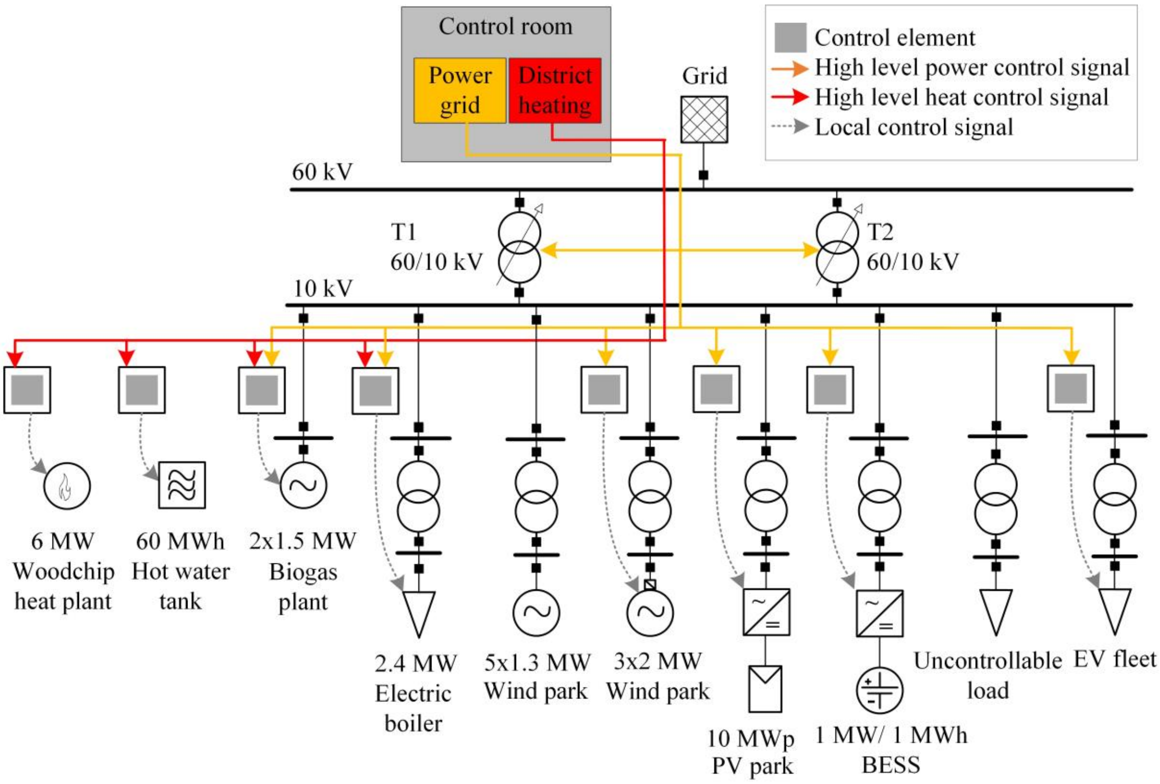

Figure 1: Single line diagram with included control architecture based on [5].

2.1 Biogas plant

Bornholms Bioenergi co-generation biogas plant depicts a central element of the future local multi-energy system of the island. It provides options for incorporating new local biomasses (animal residuals, secondary crops, household and garden wastes, etc.) for multi-energy services, and for producing alternative transportation fuels such as biomethane and methanol. The biogas plant is electrically connected on the low-voltage side of the 60/10 kV substation in Aakirkeby. The plant has a nominal electrical output power of 3 MW composed of two identical co-generation units running on biogas. Moreover, the plant is embedded with its nominal thermal output power of 3.776 MW_{th} in the local DHN supplying the townships of Aakirkeby, Lobbæk, Nylars and Vestermarie. During summer, the thermal demand in the DHN is met by the biogas plant alone, while in winter, designated heating plants running on woodchips and oil are used to fulfil the heating requirements [6]. These plants are envisioned to be phased out during the decarbonisation strategy of the island.

The biogas plant was recently upgraded by two new generators in 2019, thereby increasing the electricity and heat production from local resources on the island. During the plant upgrading, the metering was changed: Before the upgrade, self-consumption for electricity was behind-the-meter, while net electricity was sold to the grid. Today, all electricity from the biogas plant is sold and electricity for the process is purchased. Table 1 reports the estimated average production values for the old plant configuration for the years before 2019 (with two units of type JMS 320 GS-BL with 1 MW each) and the prospective values for the new configuration in 2021 (two units of kind JMS 420 GS-BN.LC with 1.5 MW each).

Table 1: Historical and prospective production values for 2019 (old plant configuration) and 2021 (new configuration), respectively.

Biogas plant	**< 2019 (MWh)**	**2021 (MWh)**
Electricity production	9233	24,700
• Electricity self-consumption	733	1960
• Net electricity injected into grid	8500	22,740
Heat production	8905	23,500
• Heat self-consumption	1705	4500
• Heat sold to district heating	7200	19,000
Electricity and heat utilized	18,138	48,200
Efficiency	82.5%	95.5%
Total biogas consumption	21,9173	50,471

Figure 2 shows the secondly electrical and thermal production of one of the two identical units for the month of September 2020. The heat production is clearly following the electrical output of the generator, although fluctuating strongly in a secondly resolution. Taking average production values, however, the biogas plant has a linear dependency between the hourly electrical and thermal output. The heat-to-power-ratio of the employed combined heat and power (CHP) units is 1.257, meaning that at electrical full load of 1.5 MW the heat production of one generator is on average at 1.89 MW [6].

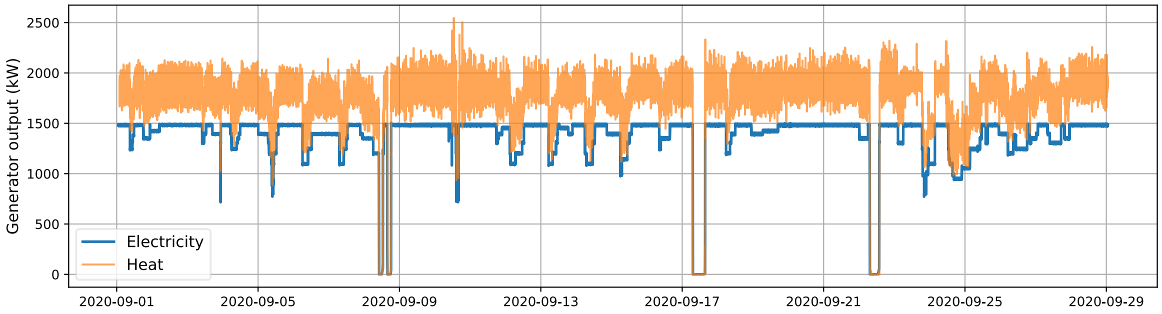

Figure 2: Secondly electricity and heat production of the biogas plant in September 2020.

Figure 3 presents the distribution of 2-minute gas storage measurements taken in the month of November 2020. The figure illustrates that the gas storage level is often filled around 30% or 60%. The distribution is generally positively skewed (right skewed) with more data points towards the lower end of the gas storage level.

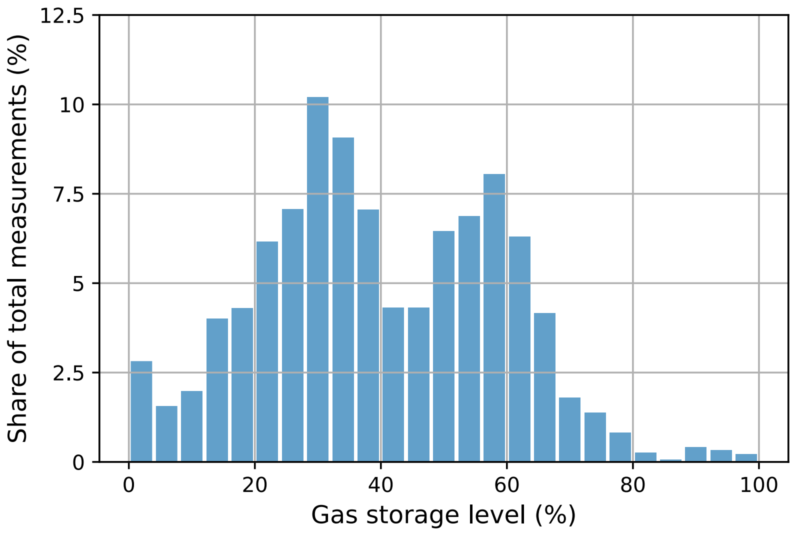

Figure 3: Histogram of 2-minute gas storage measurements in November 2020.

2.2 Wind farms

The two large-scale wind farms under analysis are installed in Kalby and Sose, and electrically connected to the substation of Aakirkeby.

Kalby wind farm (WF) (6 MW) is composed of three Type C wind turbines with a nominal power of 2 MW each and a nominal voltage of 690 V. Each wind turbine (WT) has an individual transformer (11/0.7 kV, nominal apparent power of 2.1 MVA). The first WT is connected to the substation via a double under-ground cable connection, while between the two consecutive WT a single under-ground cable connection is installed. Sose WF (6.5 MW) is composed of five Type A WTs with nominal power of 1.3 MW each and nominal voltage of 690 V. Each WT has an individual transformer (11/0.7 kV, nominal apparent power of 1.6 MVA). The underground connection is done following the same structure as in Kalby WF. Table 1 collects some detailed data of the installed turbines.

Table 1: Wind turbines composing Kalby and Sose wind farm [7].

Turbine number (GSRN)	Date for original grid connection	Capacity (kW)	Rotor diameter (m)	Hub height (m)	Producer
570714700000105760	2002-12-12	1300	60	60	Nordex
570714700000105777	2002-12-12	1300	60	60	Nordex
570714700000105784	2002-12-12	1300	60	60	Nordex
570714700000105791	2002-12-12	1300	60	60	Nordex
570714700000105807	2002-12-12	1300	60	60	Nordex
570714700000107016	2006-04-10	2000	80	60	Vestas Wind Systems A/S
570714700000107023	2006-04-10	2000	80	60	Vestas Wind Systems A/S
570714700000107030	2006-04-10	2000	80	60	Vestas Wind Systems A/S

Figure 4 illustrates the hourly boxplots of the measured wind production of Kalby (left) and Sose WFs (right) for the year 2019. For Kalby WF, the yearly energy production was 15.076 GWh, equivalent to 2513 full load hours (28.7% of 8760 hours), whereas for Sose WF the yearly energy production was 13.662 GWh, equivalent to 2102 full load hours (24% of 8760 hours). The boxplot shows the distribution of the wind production throughout the day. The median for the single hours is depicted as a red bar, while the blue boxes signify the interquartile range of the distribution. The whiskers extend to maximum 1.5 of the interquartile range. With the median being rather steady, the boxes cover a large power range from 500 – 3000 kWh/h, signifying a high variability of the wind production independent of the hours of the day.

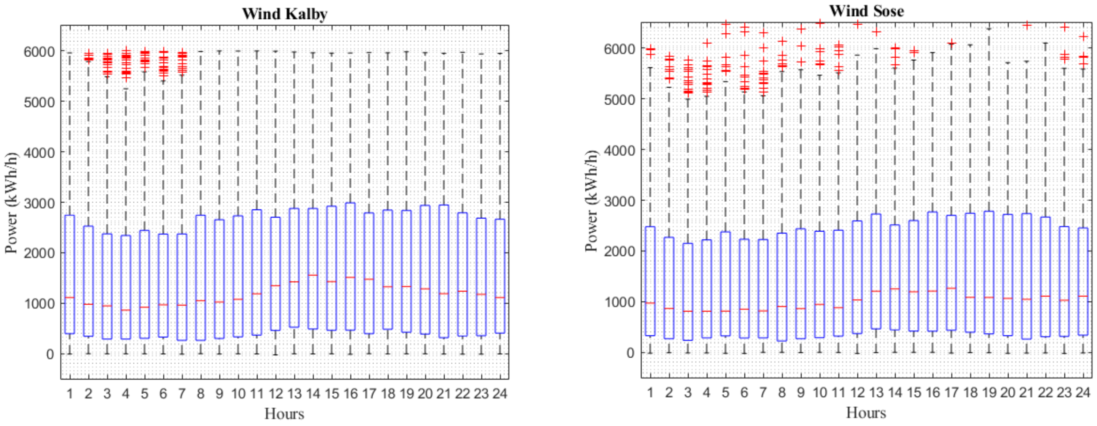

Figure 4: Production patterns of the wind farms in Kalby (6 MW) and Sose (6.5 MW).

2.3 Photovoltaic park

The PV park is located to the south-west of the city of Aakirkeby. It has a total DC rating of 10 MWp consisting of three equally sized 10/0.48 kV transformer station of 2.5 MVA each. Each transformer station connects up to 29 inverters, while each inverter links 18 strings in parallel that are each composed of 24 PV modules in series. The rating of the PV modules ranges between 255 – 275 Wp. Figure 5 illustrates the structure of the PV park in a single-line diagram. This utility-scale PV plant has been installed in an open-field installation with southward facing modules.

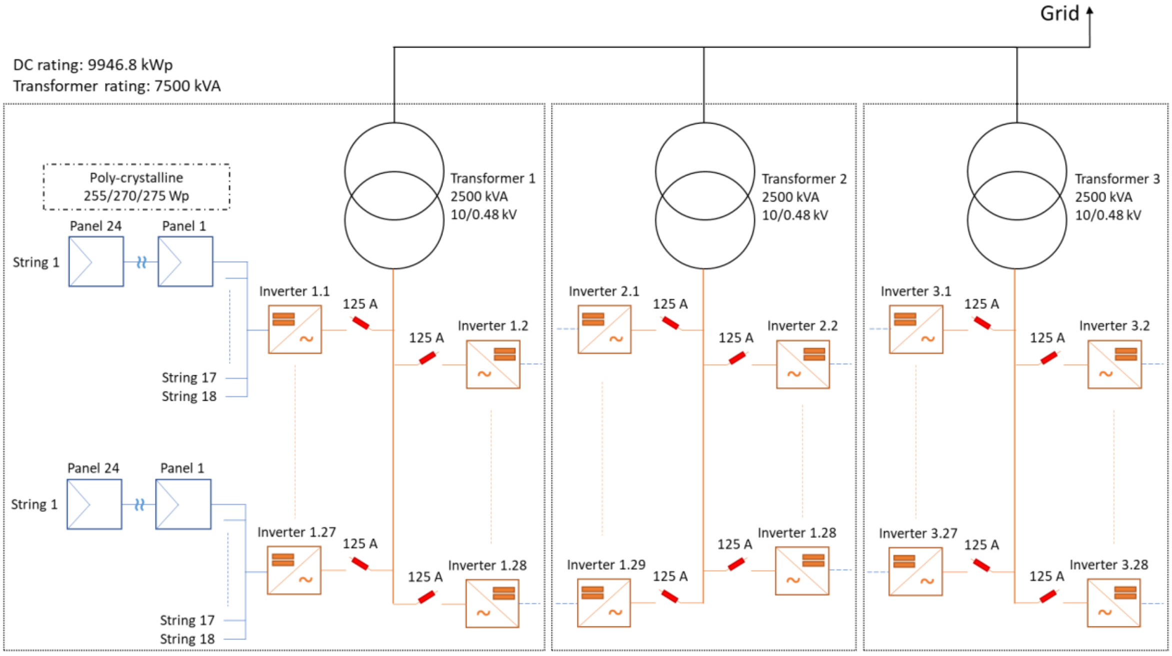

Figure 5: Single-line diagram of the PV park in Aakirkeby.

The yearly energy production of the PV park adds up to around 10.5 GWh (measured for the year 2019), which corresponds to 1400 full load hours (16% of 8760 hours) on the medium-voltage side of the transformers. The tender for the PV park has been won by European Energy at the end of 2016 and installed subsequently. The plant was granted an initial feed-in tariff of 5.38 €cent/kWh, together with a price surcharge that was down to 0.4 €cent/kWh the year after.

Figure 6 illustrates the hourly boxplots of the measured PV production of the year 2019. The production extends during summer from 6 am in the morning to 9 pm in the night, while the peak production reaches up to 7.3 MW during midday. In winter months, the PV production is compressed to the hours between 10 am and 5 pm, with peak production reaching only 3 MW in exceptional cases. Due to seasonal circumstances, the PV production spreads largely for the hours of the day in the different month.

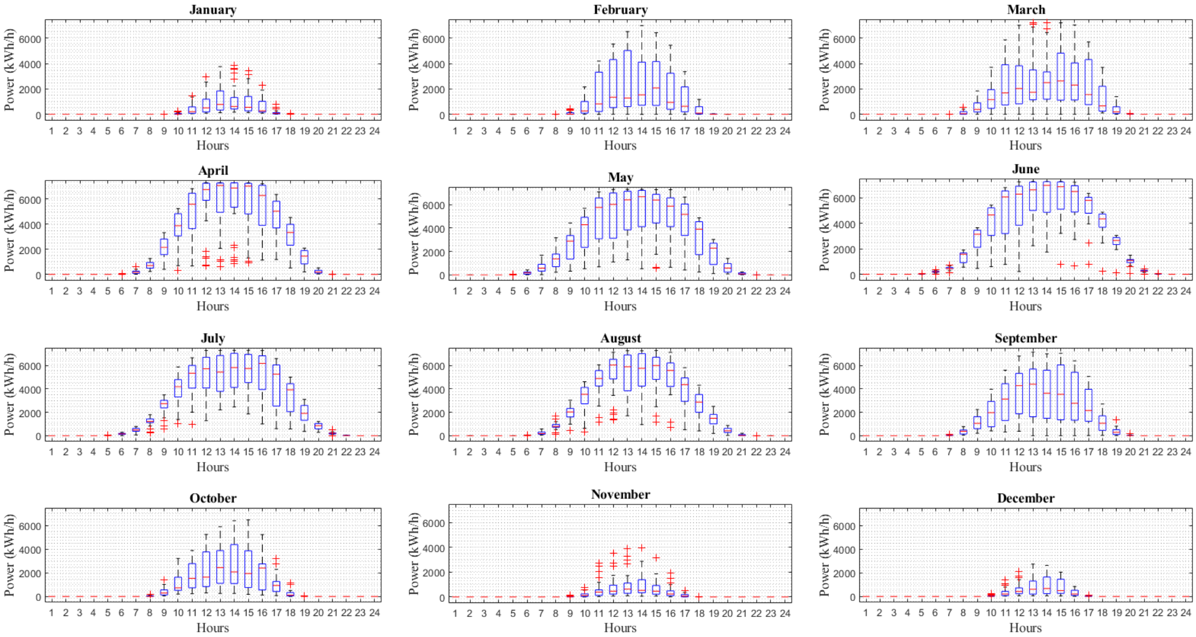

Figure 6: Hourly boxplots of the PV production in the months of 2019.

2.4 Electric vehicle fleet

Among the generation and consumption feeders at the 10 kV bus of the Aakirkeby substation, the EV fleet represents as of yet a fictitious amount of EVs charging which is likely to happen in the upcoming years, due to Danish subsidies and support for the green transition of the transportation sector [8]. Thus, a scenario with 100% EV penetration in Aakirkeby is modelled to test EV smart charging strategies and related controllers.

To properly represent the EV fleet, driving statistics of the Danish population and attributes of existing electric vehicles in the market were examined. Starting from driving statistics of the Danish population, one of every two citizens owns a car in Aakirkeby. Considering a 100% EVs penetration scenario, and the pseudo-real driving analysis of EVs reported in [9] and [10], it is assumed that 1065 EVs are available in the town. Regarding the on-board battery capacity, it is related to the EV models composing the fleet. For the current analysis, the EV fleet is considered to be composed of Nissan LEAF 2018, with a 40 kWh lithium-ion battery and average driving consumption of 0.2 kWh/km. Moreover, it is assumed EVs are charged via domestic chargers. Both three-phase (rated power 11 kW, 400 V, 16 A) and single-phase (rated power 3.7 kW, 230 V, 16 A) unidirectional domestic chargers are considered. For the sake of simplicity, chargers are assumed to be directly connected to the 10 kV bus, thus neglecting transformers and low-voltage distribution losses, and with an efficiency of 90% during charging.

2.5 Electric boiler and district heating network

An electric boiler depicts in this presented VPP a highly efficient intermediary between the electrical and the thermal domain. The electric boiler is composed of four equally sized 600 kW units with a nominal voltage of 690 V of the model EP 600 SSR from the Swedish company *Värmebaronen*, leading to a total nominal power of 2.4 MW. The boiler is assumed to be connected to the district heating network connecting the townships of Aakirkeby, Lobbæk, Nylars, and Vestermarie. The hourly heating demand during winter is up to 5 MWh, while in summer it is only around 1 MWh. The district heating network includes a thermal storage of 60 MWh as well as a 6 MW heating plant running on woodchips.

2.6 Residential and industrial consumption

The substation of Aakirkeby lies in between Rønne and Bodilsker on the southern part of the island, electrically connected via a 60 kV line. The substation connects besides the production units also different consumption feeders that supply both residential and industrial areas. As of January 2020, the township of Aakirkeby has approx. 2100 inhabitants, a small industry area and a public school. For 2019, the aggregated electrical energy consumption summed up to around 20 GWh, with a peak load of just under 4 MW. Figure 7 shows hourly boxplots for the aggregated inflexible load from all consumption feeders for the year 2019. The boxplots are denser compared to the ones for the wind and PV production during the year, due to less variability in the aggregated consumption pattern.

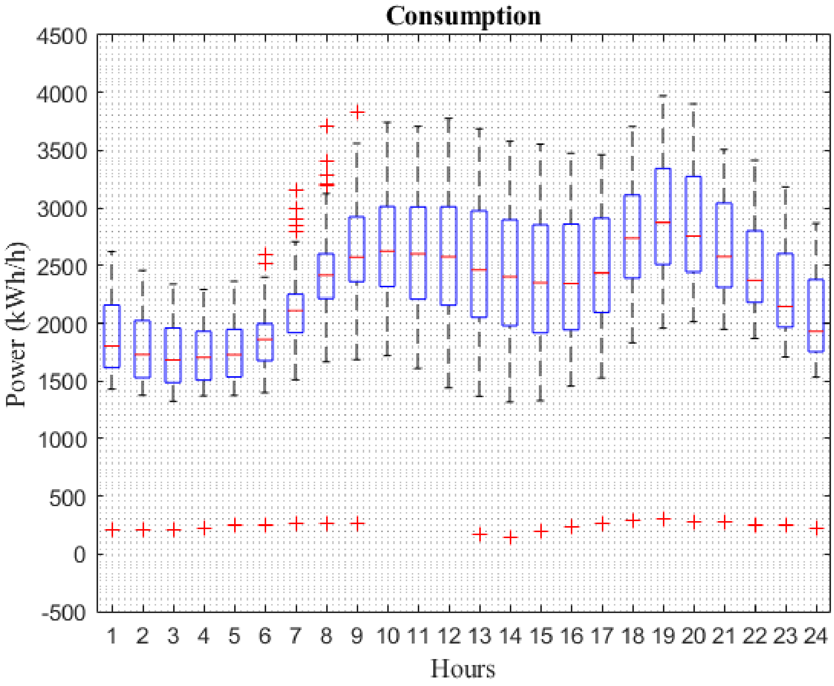

Figure 7: Pattern of the inflexible consumption feeder at the substation of Aakirkeby.

2.7 Future connected components

In the future, it is envisioned to upgrade the VPP at Aakirkeby by different components. In the year 2021, a 1 MWh / 1 MW BESS will be installed in the scope of the EUDP funded Bornholm Smartgrid Secured (BOSS) project. The project envisions to demonstrate the profitability of services provided by grid-connected BESS. To date, the battery will be the largest grid-connected battery in Denmark. For more information, refer to [11]. Recent work has so far investigated placement of battery storages from a business perspective [12].

In the rather distant future, the substation of Aakirkeby could also be an interesting site choice for power-to-X facilities such as an electrolyser that can produce hydrogen via renewable-powered water electrolysis. Currently, work has started in different projects on multi-MW electrolysers in the range of 20-30 MW (e.g., in Northern Germany in the *Westküste 100* project). There are different kinds of electrolyser types (Alkaline-Water, Proton-Exchange Membrane, Solid-Oxide). Of these, Proton-Exchange Membrane (PEM) electrolysers are the most promising in the connection with variable renewable energy sources, until solid-oxide electrolysers become mature enough. PEM electrolysers can change their load within the range of a couple of seconds and thus offer good compatibility with fluctuating renewable power output. Hence, the following data description will focus on PEM electrolysers only.

Current PEM electrolyser systems demand approx. 55 kWh of electrical energy, including compression, to produce 1 kg of hydrogen (H_2) [13]. A kg of hydrogen has a higher heating value of 39.4 kWh, and hence, the system has an electrical efficiency of 71.6%. Moreover, it is assumed that the process heat can be reutilized for the district heating (up to 15% of the input energy). The capital costs for electrolysers are rapidly declining (like battery storage systems) and are expected to continue decreasing. Today, the costs for a large-scale electrolyser system are ranged between 1000 – 1500 €/kW. By 2050, they are expected to be down to 400 – 500 €/kW [14]. The lifetime of an electrolyser is assumed to be 20 years, with a possible stack replacement after 10 years [15]. However, the exact lifetime of large-scale electrolysers in operation must be verified over time.

3 SIMULATION STUDIES AND RESULTS

The goal of this deliverable D4.9 is to gather the key results of the simulation studies connected to the Use Case 5. This Use Case aims at assessing the integrated management of local bio-based economies supporting different energy domains on the Danish island of Bornholm. Figure 8 gives a graphical overview on the topics covered by the performed studies. The focus of the Use Case lies in the development of a VPP at the substation of Aakirkeby for exploiting the flexibility potential of connected units to address the challenges that arise from inflexible generation and consumption patterns.

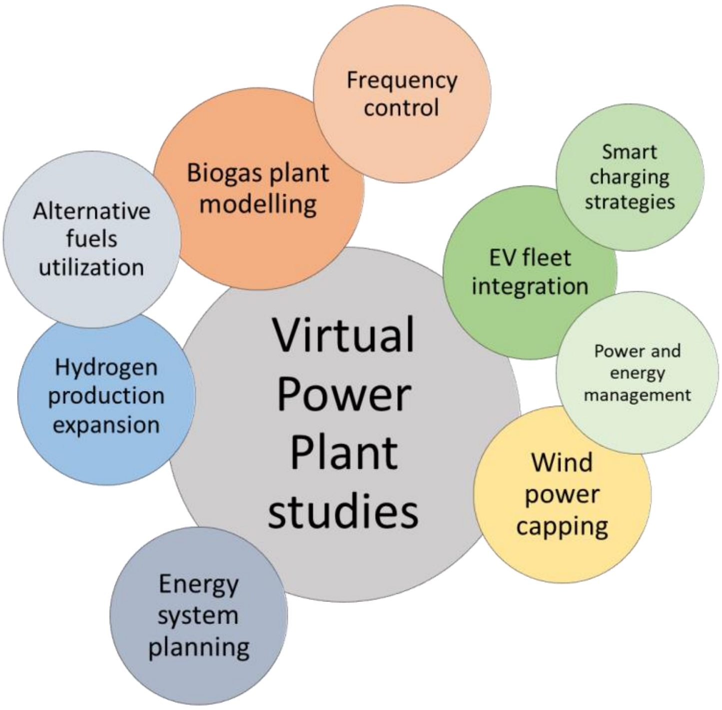

Figure 8: Overview on the simulation studies associated with the Virtual Power Plant.

In the following, the different topics will be presented in the following order:

1. The biogas plant in Bornholm is characterized and empirically validated. Subsequently, its potential for the provision of frequency control on the island is presented, both in in terms of technical and economic feasibility.
2. The results of power and energy management strategies for the prospective integration of an EV fleet are presented.
3. Wind power capping capabilities are studied by modelling the transient behaviour of the wind turbines in the Kalby WF.

4. The potential extension of the VPP for green H_2 production is studied in a techno-economic optimisation framework, sizing an electrolyser at the biogas plant site. The production potential of alternative fuels for transportation purposes on the island is examined.
5. The impact of different interventions in the VPP Aakirkeby is examined in terms of yearly output in the energy system planning tool from the local DSO.

3.1 Biogas plant modelling and frequency control

Biogas plants can be a crucial element of insular power systems as they provide controllable heat and electricity generation, as well as flexibility on the generation side that is needed in systems without large balancing reserves. They can hence offset the application of fossil fuels, and thereby emissions of greenhouse gases. In the combination with renewable-based energy systems, biogas plants can provide grid balancing services to make up for the volatile generation from renewable energy sources. To this end, we have attempted to characterize the internal processes of a biogas plant from an electrical perspective and investigated the provision of frequency control of a biogas plant in the Danish regulatory context. The biogas plant simulation model is described in detail in two recently published, peer-reviewed articles [6] and [16]. Here, we provide the main insights from the performed simulation studies.

To model the complex biochemical process of a biogas plant with its anaerobic digestion processes coupled to the electrical and thermal energy generation, it is necessary to breakdown the simulation in smaller parts and make careful assumptions that simplify the modelling without compromising the dynamic behaviour of the process. Figure 9 illustrates the modelling approach presented in [6] as a block diagram.

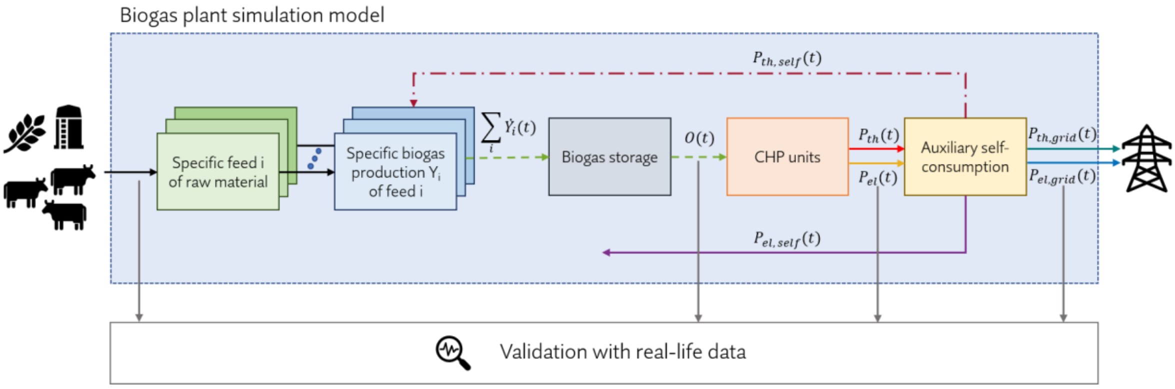

Figure 9: Modelling approach for a biogas plant simulation model [6].

The model takes daily or hourly time series of the infeed as input. Each time-amount tuple of the feeding is subsequently converted to a specific biogas production rate via the first-order derivative of a modified Gompertz function. The accumulated biogas production of the subsequent feedings is then fed into a biogas storage. The storage couples the biogas production and the gas consumption of (here two equally sized) CHP units. Lastly, the thermal and electrical auxiliary self-consumption of the facilities in the plant are subtracted from the output of the generators for determining the magnitude of grid injections, both in terms of electrical and thermal energy. The model has been implemented in MATLAB & Simulink.

Figure 10 plots the output of the model from a daily feeding schedule. The upper subplot illustrates the daily feeding schedule considered in this study in wet weights of animal slurry (marked in blue), together with the monthly average for daily feedings (marked in red). The evolution of the individual biogas production rates is depicted in the second subplot of Figure 10. According to the logic of the modelling approach, each feeding has an individual biogas production rate, following the first-order derivative of the modified Gompertz function. The third subplot of the figure shows the cumulated biogas production associated with each feeding instance. The different processes are then aggregated to receive the total biogas production rate of the biogas plant from the daily feeding schedule, visualized in the fourth subplot. The total gas production ranges around 0.28-0.32 m³/s, corresponding to a flow rate of approximately 1008-1152 m³/h. In one day, the biogas plant produces around 25,000 m³ of biogas per day and hence 750,000 m³ per month.

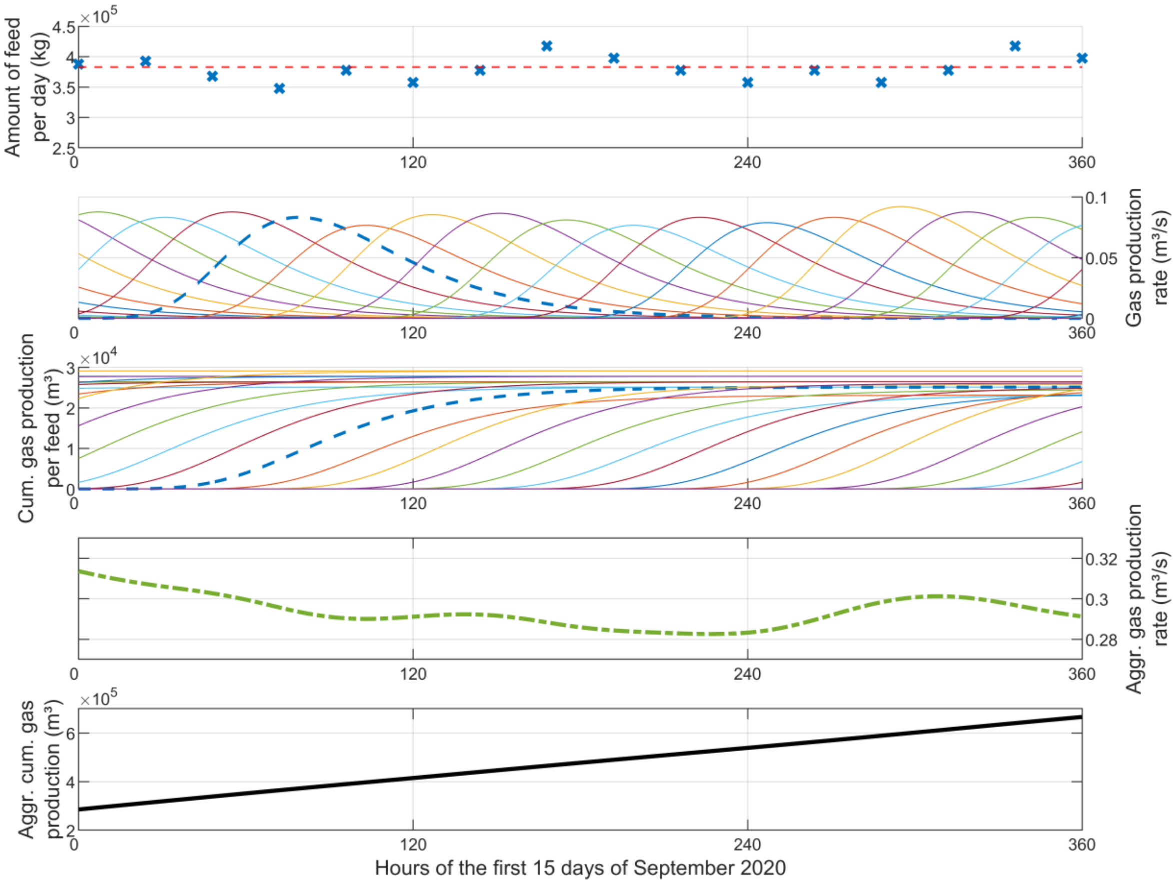

Figure 10: Biogas production dynamics for specific feedings instances over the first half of September 2020 [6].

Figure 11 shows the hourly electrical energy output of the plant for the month of September 2020. The electrical set-points given to the model can always be satisfied, while the level of grid injection and self-consumption of the plant can be determined with high accuracy. The simulated grid injections only overshoot the measurements at the feeder by 0.15%, while the simulated self-consumption in the model underestimates real measurements by 3.1%. In terms of thermal generation, the model slightly overestimates the heat output of the plant by 0.65%. From a total monthly heat generation of 2.464 GWh, 359.2 MWh have been used on-site which amounts to a simulated thermal self-consumption of 14.58%. In summary, the differences of the simulation results compared to the real-life measurement are insignificant, which means that the model with all its assumptions is providing an accurate representation of the processes of the biogas. It can be noted here that the biogas storage, depicted in the lower part of Figure 11 provides the flexibility for the co-generation of heat and power in the CHP units. While on some occasions, the storage level hits the upper bound of the low-pressure gas storage tank, it is well filled for most of the simulation horizon. The biogas storage level might be overestimated by the presented modelling approach by neglecting the biochemical reactions in a continuously stirred digestion tank which will have an impact of the biogas productivity of the microbial bacteria population.

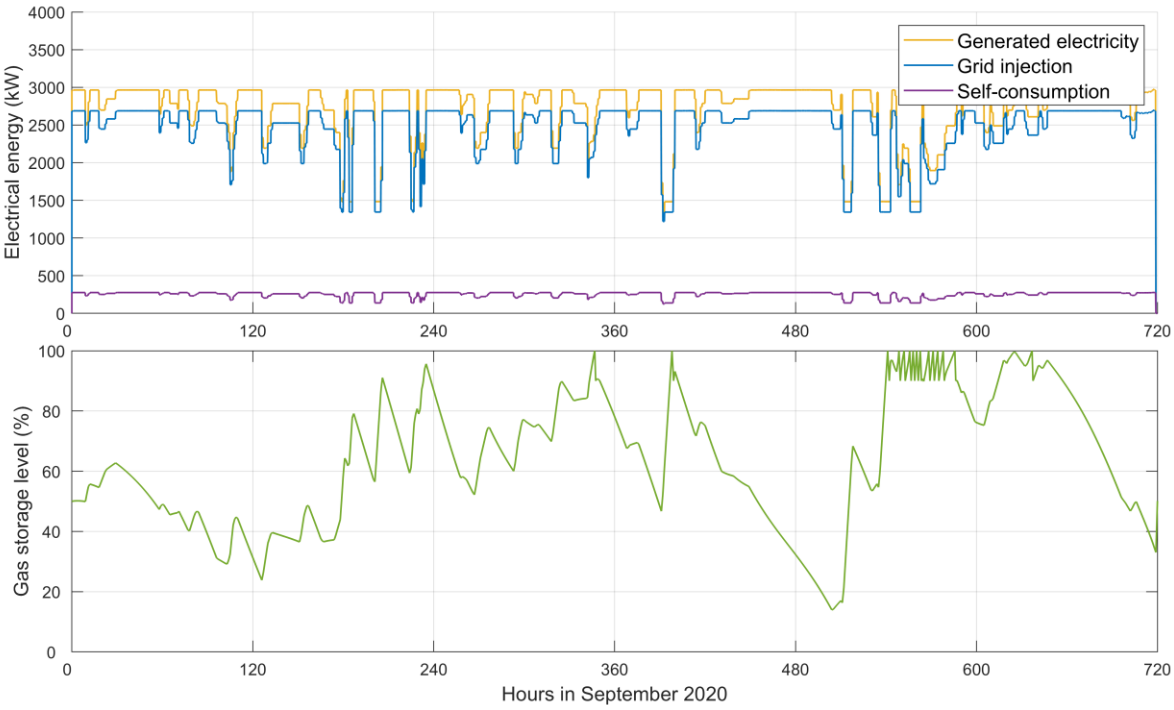

Figure 11: Electrical energy output together with the simulated grid injection and the simulated self-consumption (upper plot), as well as gas storage evolution (lower plot) throughout the month of September 2020 [6].

In summary, it can be noted that the developed simulation model representing the main dynamics of the internal processes of a biogas plant accurately matches the historical measurements of the biogas plant on Bornholm. By taking into consideration the transients of the anaerobic digestion based on first-order kinetics, the gas storage, the CHP units, as well as the auxiliary self-consumption of the plant, the model can simulate the functioning of the plant also for unknown power requests.

Frequency control provided by a biogas plant

In the following, simulation results of an investigation regarding the provision of frequency control from the biogas plant are presented. Frequency control is a necessary action in an electric power system to maintain the balance between production and consumption and to avoid unexpected disturbances that may lead to damages at the connected loads or system failure. The work is reported in detail in [17].

Figure 12 gives an overview of the model structure for the provision of frequency control of a biogas plant. The controller calculates a new power set-point as the sum of the initial power reference and a power deviation ΔP. The power deviation is calculated based on a variation in the grid frequency with reference f_{ref} of 50 Hz and a corresponding droop gain k_{droop}.

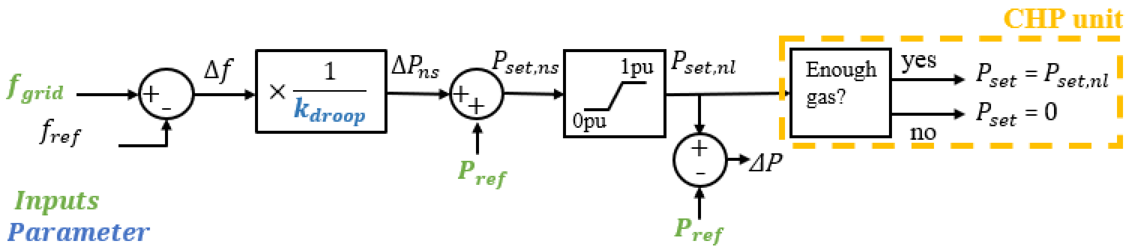

Figure 12: Model structure for the provision of frequency control of a biogas plant [17].

The value of the k_{droop} can vary and has been tested within this study for the values specified in the grid code, i.e., from 2% to 12% [18]. When the k_{droop} is smaller, the controller is more sensitive to frequency variations, and vice versa. Thus, depending on the level of P_{ref}, the maximum capacity of 1 per unit (p.u.) is reached faster with smaller k_{droop}. For the study, half-second frequency data for the month of November 2020 were used.

Table 2: Number of hours when capacity reserve is available in November 2020 (out of 720 h).

k_{droop}	2%	4%	6%	8%	10%	12%
Available reserve for FCR-N (h)	258	560	579	593	613	618
Available reserve for FCR-N and FCR-D (h)	0	46	104	186	258	360

Figure 13 shows the p.u. set-points under different k_{droop} values for providing FCR-N (frequency containment reserves in normal conditions) and FCR-D (frequency containment reserves in disturbance conditions) without any additional reserves kept for the services. The controllers are deactivated when no reserve for frequency control is available. A k_{droop} of 2% results in a stronger variation of the power set-point for the biogas plant. Hence, to perform frequency control with such a small k_{droop}, a high level of reserves must be kept available.

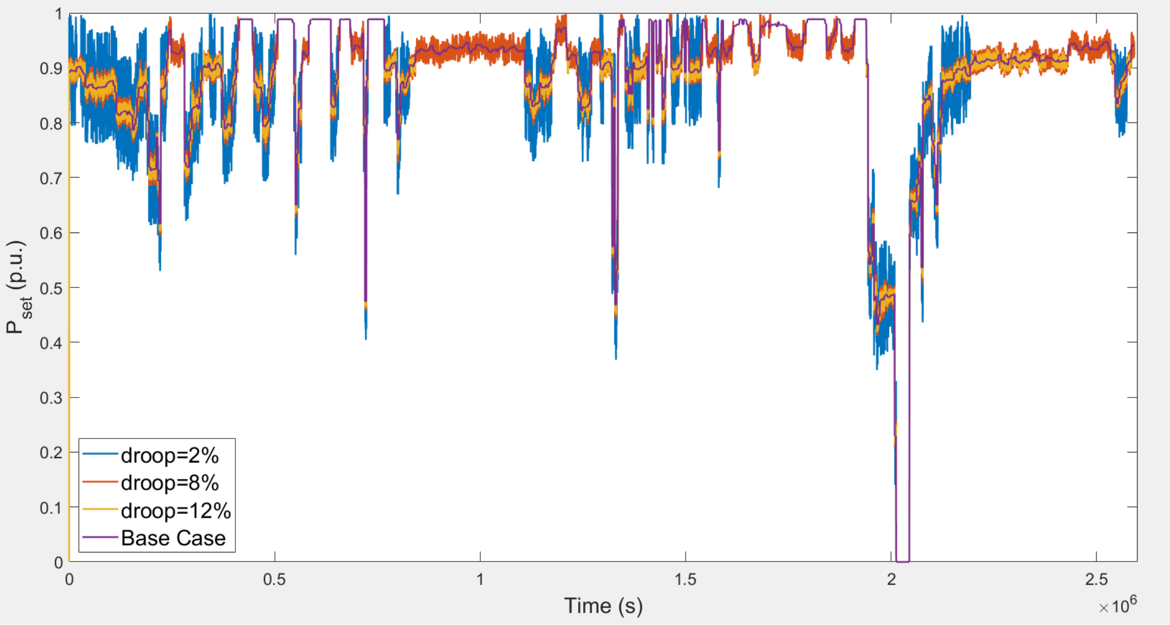

Figure 13: Power setpoints for FCR-N and FCR-D for the month of November 2020 under different droops [17].

Different cases have been investigated to understand the provision of frequency control under different circumstances. We have identified four cases that provide FCR-N and FCR-D with and without additional reserves kept.

Due to balanced frequency deviations over the month, also the cumulated power deviations compared to the base case are rather small, hence the mean power production is close to the mean reference production. To provide symmetric frequency control with small k_droop, a reserve must be kept which has a strong impact on the gas storage level and hence the feeding of raw material. Less electricity production at the same feeding would of course lead to higher levels of storage. The energy content of FCR-D is very limited compared to FCR-N.

Table 3: Overview on the considered cases for frequency control.

	FCR-N activated	FCR-D activated	Add. reserve for FCR-N	Add. reserve for FCR-N
Base case				
Case 1	X	X		
Case 2	X	X	X	
Case 3		X		
Case 4		X		X

The presented cases are subsequently examined from an economical point of view, taking into consideration the payments made from the governmental support scheme, capacity reserve and balancing prices, as well as the levelized cost of electricity from biogas. Table 4 presents the profits of the biogas plant during one month of operation in the four investigated cases, performing FCR-N or FCR-D either with or without additional reserves.

Table 4: Comparison of profits in the four investigated cases.

	k_{droop}	2%	4%	6%	8%	10%	12%
Case 1	Profits in €	150 705	151 060	150 777	150 701	150 644	150 637
	Compared to Base case (%)	0.91	1.15	0.96	0.91	0.87	0.87
Case 2	Profits in €	148 350	150 348	150 454	150 552	150 563	150 625
	Compared to Base case (%)	-0.67	0.67	0.74	0.81	0.82	0.86
Case 3	Profits in €	149 644	149 774	150 035	150 180	150 307	150 354
	Compared to Base case (%)	0.20	0.29	0.46	0.56	0.64	0.68
Case 4	Profits in €	108 786	135 786	143 796	146 997	148 409	149 050
	Compared to Base case (%)	-27.16	-9.08	-3.72	-1.57	-0.63	-0.20

The profits in cases 1 and 3 are generally higher compared to the Base case profits without any frequency control (149 344 €). In these cases, the plant receives approx. the same revenues for the reference production, plus additional payment from frequency provision. In Case 2, the revenues were lower for the smallest k_{droop} because of the capacity reserve that was kept being able to provide FCR-N throughout the month. The loss of profit in Case 4 is also due to the large capacity reserves held available in the cases of small k_{droop}.

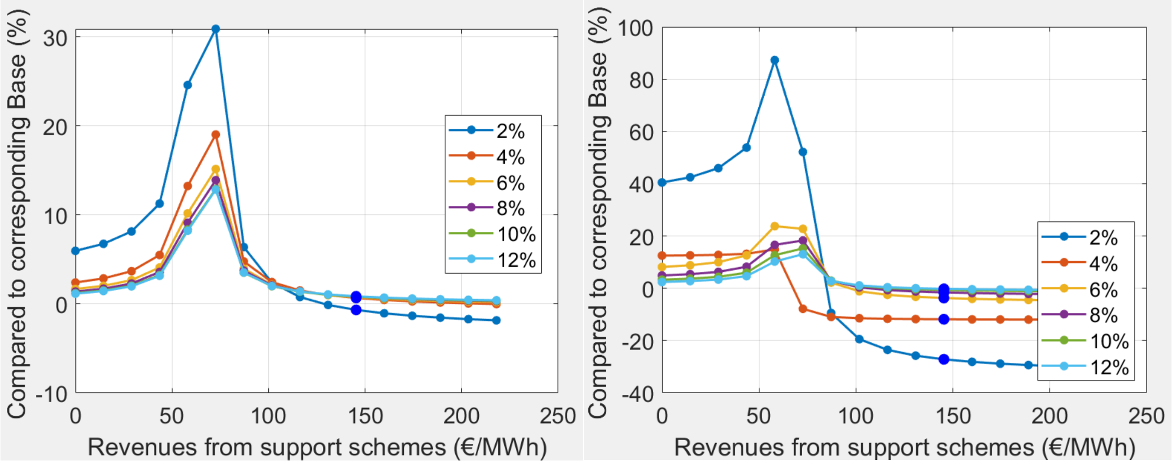

Figure 14: Sensitivity analysis of profits for different payments from the support schemes in Case 2 (left) and Case 4 (right). The blue marker indicates the current level of the subsidy [17].

Figure 14 plots the evolution of profits for different subsidy values from the support scheme. The marginal profits due to frequency control tend to increase with decreasing support from the government. An important breakpoint is the LCOE of the biogas plant (assumed here at 67 €/MWh) that impact the depiction in relative terms. The peak corresponds to the point where the base profit is zero, as revenues equal costs, and hence the percentage increases. However, a depiction in absolute terms would not provide sufficient visual explanatory power.

3.2 Power and energy management for EV fleet integration

Renewable energy sources such as wind and solar are highly variable, non-dispatchable, and have a limited predictability. Consequently, the renewable production at Aakirkeby substation could differ from their scheduled energy plan, increasing the dependency on advanced forecasting methods. Simultaneously, sudden oscillations of wind speeds in the WFs Kalby and Sose, as well as unpredictable variations of solar radiation in the PV park are translated into fluctuating power injections at the 10 kV side of the substation. Consequently, the *Energy Management* and the *Power Smoothing* are becoming services of fundamental importance for enhancing the controllability of the VPP at the Aakirkeby substation.

Figure 15 represents the layout of the system under investigation. Power or energy measurements from the substation are collected and sent to a Fleet Aggregator (FA). As a function of the received measurements and the reference signal to be satisfied, the FA controls remotely the EV fleet, adjusting their charging current set-points. Two approaches are then investigated in this section. Firstly, the performance of Kalby wind farm is analysed when supported by the EV fleet. Particularly, the charging power of the EV fleet is modulated as a function of the fluctuating power produced from the wind farm. The goal of this first approach is to define two smart charging controllers and apply the *Energy Management* or the *Power Smoothing* service. Secondly, all renewable energy power plants in Aakirkeby (Kalby and Sose WF, PV park and biogas plant) are considered, as well as the inflexible local consumption at the substation. The goal of this second approach is to assess the self-consumption of a set of VPP configurations under different controlled EV charging strategies. To do so, instead of charging the EVs as soon as they are grid-connected, the FA will charge the EVs when there is a power surplus, namely when the renewable production exceeds the inflexible local consumption. For both analyses, domestic EV chargers are considered, which do not give the possibility to the FA to track on real-time the State-of-Charge (SOC) evolution while charging. Consequently, when an EV is plugged-in, it is assumed the SOC level is communicated from the EV owner back to the FA, to allow the FA to estimate the available storage capacity left.

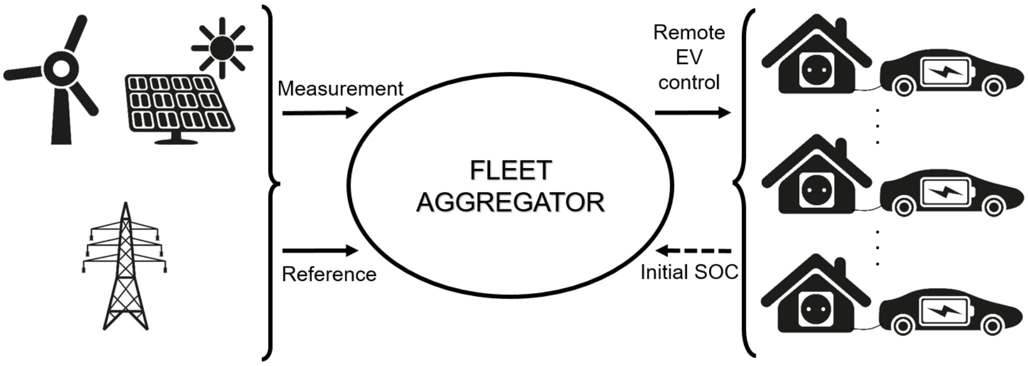

Figure 15: System layout for power and energy management for EV fleet integration [19].

For the carried analysis, the following input data with second-by-second time resolution is used:

- Power measurement profiles at the 10 kV side of Aakirkeby substation.
- Power generation profiles for each WT of the Kalby WF with controllable wind turbines.
- EV load behaviour profile.

Power Smoothing and Energy Management applied to Kalby wind farm

The analysis is described in detail in a paper currently under review [19]. Here, we provide the main insights from the performed simulation studies.

The impact of wind power fluctuations at the Aakirkeby substation is observed considering the power generation for Kalby WF, reported in the upper subplot of Figure 16. The data correspond to the active power production from 21st January 2020 at 6pm to 22nd January 2020 at 6am (12 hours timeline). To quantify the wind power fluctuations, the coefficient of variation (CV) is introduced, and it is defined as the ratio between standard deviation and mean power production of the WF.

$$CV = \frac{STD(WF_{output})}{mean(WF_{output})} \quad [-]$$

The lower subplot in Figure 16 represents the hourly WF mean production (blue), and the hourly WF reference power (red), and their values are reported in Table 5. The reference power is obtained from the forecasted energy plan, which is manually chosen to determine a ±5% error in the hourly WF energy production, with respect to the forecast.

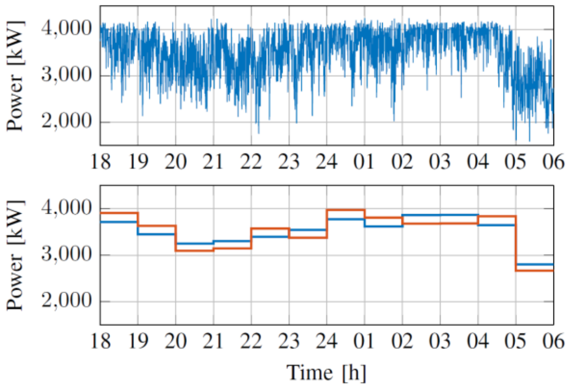

Figure 16: Kalby WF power production (upper subplot), mean production (blue) and reference power (red) (lower subplot) [19].

Table 5: Hourly energy production and forecasted energy plan.

Time [h]	Production [kWh]	Forecast [kWh]	Time [h]	Production [kWh]	Forecast [kWh]
18 – 19	3713	3908	24 – 01	3774	3972
19 – 20	3449	3631	01 – 02	3617	3807
20 – 21	3250	3095	02 – 03	3863	3679
21 – 22	3302	3145	03 – 04	3866	3682
22 – 23	3395	3574	04 – 05	3646	3828
23 – 24	3544	3375	05 – 06	2800	2666

The first proposed controller is the *Power Smoothing Controller (PSC)*, a power controller which task is to adjust the charging current of the EV fleet based on the power deviation between Kalby WF production and the reference power to inject at the substation. This deviation is the input of a Proportional-Integral regulator with a back-calculation anti-wind up control. The output of the regulator is the new charging current set-point.

The second proposed controller is the *Energy Management Controller (EMC)*, an energy controller which task is to adjust the charging current of the EV fleet based on the energy deviation between hourly energy production and the forecasted energy plan of Kalby WF. This deviation is the input of a droop regulator, which is a pure proportional control logic. The new charging current set-point, output of the regulator, is related to the energy mismatch linearly: the larger the energy deviation, the greater the variation applied to the charging current.

The role of the FA is to manage the EV fleet, to coordinate interests of both EV owners and Kalby WF. Considering the 1065 EVs represented with the EV fleet, 480 EVs (meaning 45% of the total) are charged daily. The plug-in hour is fixed at 6pm for all the EVs in the EV fleet, with a plug-in SOC of 62% on average. The FA divides equally the 480 EVs into six groups of 80 EVs, and each single group will be charged separately for two consecutive hours, starting at 6pm with the first group and concluding at 6am with the sixth group. Splitting the EV fleet into groups prevents that all EVs are charged simultaneously when plugged-in, being not able to provide services to Kalby WF as soon as the full SOC is achieved.

The two described controllers are applied singularly to the EV fleet, afterwards results are collected and a comparison between *Energy Management Controller* and *Power Smoothing Controller* is provided.

Table 6 highlights how each controller decreases the injection of fluctuations, evaluating the CV through the considered 12 hours timeline. The PSC brings a clear reduction to the coefficient of variation of 28%, while the EMC shows a drop of 5.57%.

Table 6: Fluctuations analysis with proposed controllers.

	No controller	EMC	PSC
CV [/]	11.68	11.03	8.41
Improvement [%]	0	5.57	28.0

Table 7 collects the resulting hourly WF energy production with the designed controllers.

Time [h]	EMC			PSC			Time [h]	EMC			PSC		
	Production	Error		Production	Error			Production	Error		Production	Error	
	[kWh]	[kWh]	[%]	[kWh]	[kWh]	[%]		[kWh]	[kWh]	[%]	[kWh]	[kWh]	[%]
18 – 19	3908	0.00	0.00	3804	-104	-2.66	24 – 01	3956	-16.0	-0.40	3873	-99.0	-2.49
19 – 20	3614	-17.0	-0.47	3515	-116	-3.19	01 – 02	3793	-14.0	-0.37	3689	-121	-3.10
20 – 21	3125	30.0	0.97	3190	95.0	3.07	02 – 03	3687	8.00	0.22	3710	31.0	0.84
21 – 22	3181	36.0	1.14	3226	81.0	2.58	03 – 04	3748	66.0	1.79	3747	65.0	1.77
22 – 23	3574	0.00	0.00	3449	-125	-3.50	04 – 05	3722	-106	-2.88	3677	-151	-3.94
23 – 24	3381	6.00	0.18	3442	67.0	1.99	05 – 06	2666	0.00	0.00	2739	73.0	2.74

Table 8 gathers the mean absolute errors (MAE) through the considered 12 hours timeline. The WF equipped with an EMC achieves smaller hourly energy errors than with a PSC. Moreover, a MAE of 5% without any controller drops to 2.66% with PSC, and down to 0.70% thanks to the EMC.

Table 7: Hourly WF energy production and detected energy errors with proposed controllers.

Time [h]	EMC			PSC			Time [h]	EMC			PSC		
	Production	Error		Production	Error			Production	Error		Production	Error	
	[kWh]	[kWh]	[%]	[kWh]	[kWh]	[%]		[kWh]	[kWh]	[%]	[kWh]	[kWh]	[%]
18 – 19	3908	0.00	0.00	3804	-104	-2.66	24 – 01	3956	-16.0	-0.40	3873	-99.0	-2.49
19 – 20	3614	-17.0	-0.47	3515	-116	-3.19	01 – 02	3793	-14.0	-0.37	3689	-121	-3.10
20 – 21	3125	30.0	0.97	3190	95.0	3.07	02 – 03	3687	8.00	0.22	3710	31.0	0.84
21 – 22	3181	36.0	1.14	3226	81.0	2.58	03 – 04	3748	66.0	1.79	3747	65.0	1.77
22 – 23	3574	0.00	0.00	3449	-125	-3.50	04 – 05	3722	-106	-2.88	3677	-151	-3.94
23 – 24	3381	6.00	0.18	3442	67.0	1.99	05 – 06	2666	0.00	0.00	2739	73.0	2.74

Table 8: MAE comparison between EMC and PSC.

	No controller	EMC	PSC
MAE [kWh]	175.75	24.9	94.0
MAE [%]	5	0.702	2.656

From the EV fleet perspective, a SOC analysis is carried to detect if EVs can handle the proposed service for Kalby WF, without compromising the EV owners’ driving needs for the following day. Table 9 collects the final SOC for each charging group. Considering the average plug-in SOC of 62%, the final average SOC of the EV fleet is always above 86%, and the full charge is achieved only when WF production is underestimated for two consecutive hours. Consequently, considering an energy consumption of 0.2 kWh/km, the available distance can be computed. Since the average driven distance in Bornholm is 34 km/day [9], it can be concluded that the EV owners’ driving needs are clearly ensured.

Table 9: SOC analysis for considered EV fleet.

Time [h]	EMC		PSC		Time [h]	EMC		PSC	
	SOC [%]	Available distance [km]	SOC [%]	Available distance [km]		SOC [%]	Available distance [km]	SOC [%]	Available distance [km]
18 – 20	86.2	172	91.9	184	24 – 02	86.2	172	91.5	183
20 – 22	100	200	100	200	02 – 04	100	200	100	200
22 – 24	96.0	192	97.6	195	04 – 06	98.0	196	96.7	194

In conclusion, if the power smoothing is the primary concern, the EV charging current should be modulated following a reference power, via a power controller, here defined as *Power Smoothing Controller*. Conversely, to decrease the mismatch between WF energy production and forecasted energy plan, the EV charging current should be adjusted following an energy profile, via an energy controller, here defined as *Energy Management Controller*.

EV charging strategies to maximize the self-consumption of a hybrid power plant

The goal of this part of the investigation is to assess the self-consumption of a set of hybrid power plant (HPP) configurations under different controlled EV charging strategies. The analysis shows that the active control of EV charging brings significant benefits compared to uncontrolled charging. The self-consumption of the HPP can be increased since the demand-side flexibility of the EVs allows to align the consumption to the renewable supply. In respect to the previous investigation, it is assumed that among the 1065 EVs available in the township, 700 EVs (meaning 66% of the total) are charged daily. Moreover, 11 EV user profiles represent different population groups in the society in relation to driving distance, departure, and arrival time. EVs for each profile are available only and precisely when they are scheduled to be.

The following charging strategies are considered for a set of different EV profiles:

- **S1**: Priority is given based on number of EVs within a profile.
- **S2**: Priority is given based on number of EVs and daily energy demand within a profile.
- **S3**: Priority is given based on low SOC of EVs in a profile and low amount of daily available hours to charge
- **S4**: Priority is given based on low SOC of EVs in a profile and low number of available hours left for charging

Moreover, four production scenarios from different HPP configurations are accounted for:

- **PS1**: Kalby WF, inflexible consumption and EVs
- **PS2**: Kalby and Sose WFs, inflexible consumption and EVs
- **PS3**: Kalby WF, PV park, inflexible consumption and EVs
- **PS4:** Kalby and Sose WFs, PV park, biogas plant, inflexible consumption and EVs

Figure 17 plots the charged energy by the fleet of EVs for the year 2019, divided into the energy taken from the local generation, the grid, and the sum of the two. Two things can be noted from the figure. First, a larger renewable portfolio leads to more possibilities of utilizing the surplus energy. The combination of two WFs, a PV plant and a biogas plant offers sufficient local energy production for all EVs to reach their targeted charging goal so that almost no energy is required from the grid in case of **PS4**. More local surplus leads in the carried investigation also to the fact that the total energy charged and hence the SOC of the EVs in the profiles are higher in **PS4** compared to **PS1**. Second, the proposed charging strategies all perform significantly better than the base case with uncontrolled charging. The impact of increasing complexity within the charging strategies, however, is rather low. All charging strategies lead to an increase in self-consumption of the HPP compared to a case with uncontrolled charging. The self-consumed energy is improving by 23% in **PS1**, and by 44% in **PS4**. The decline in improvement is due to the increase in probability of charging from local surplus also in case of uncontrolled charging with more renewables.

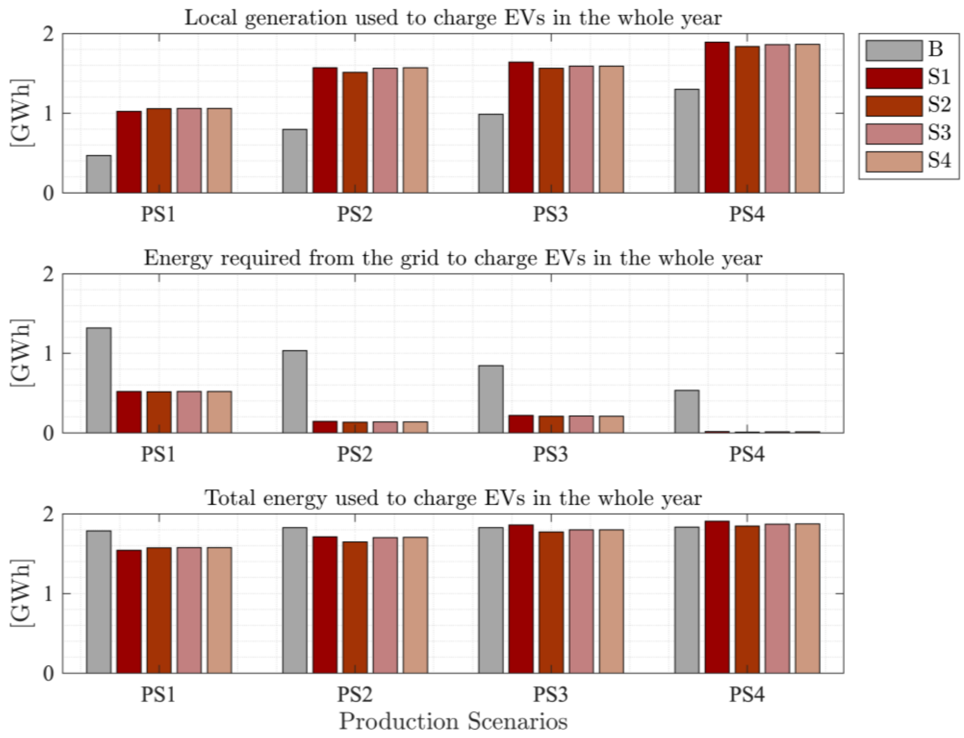

Figure 17: Annual energy consumed by EVs from local generation and the grid for each charging strategy and production scenario [20].

3.3 Wind power capping capabilities

The goal of this study is to prepare for the demonstration activities regarding the controllability of the Kalby WF at the substation. Figure 18 shows the averaged 10-minutes active power output of the three WTs plotted against the corresponding wind speeds for a period of four months. The first two WTs clearly performed power capping on different occasions.

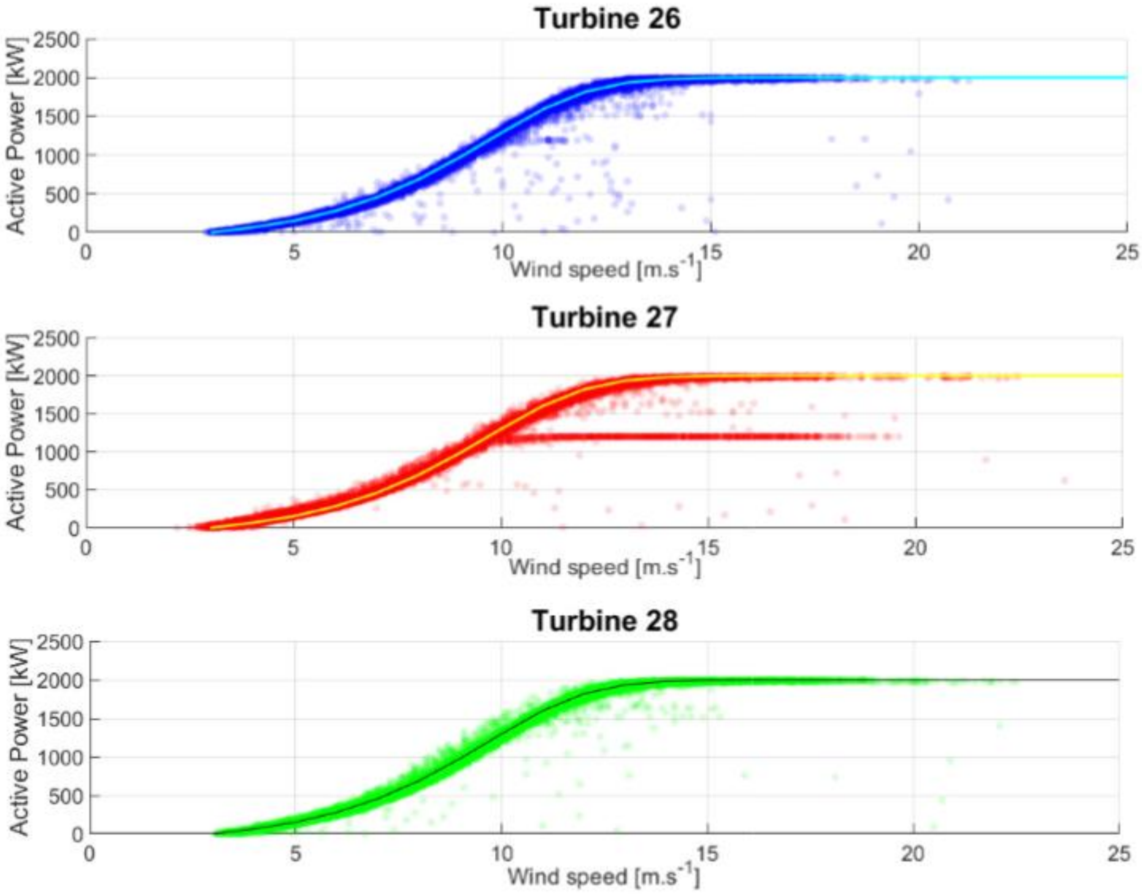

Figure 18: Observed vs. commercial power curves of the 2 MW Vestas V80 turbines [21].

Driven by historical data measurements of the 2 MW Vestas V80 WTs, the study aims at adjusting an academic PowerFactory model from a larger 6.3 MW WT to perform transient analysis and the WT behaviour of the smaller machines.

Figure 19 reports the preliminary results of the adjusted model for 13 simulations at different wind speeds, plotting both the historical measurements (in red) and the obtained simulations results (in blue) for the active output power, the generator speed, and the pitch angle. Thanks to the validation of the model, it will be possible to detect how each WT could control the produced power, decreasing the overall fluctuating power production injected at the substation.

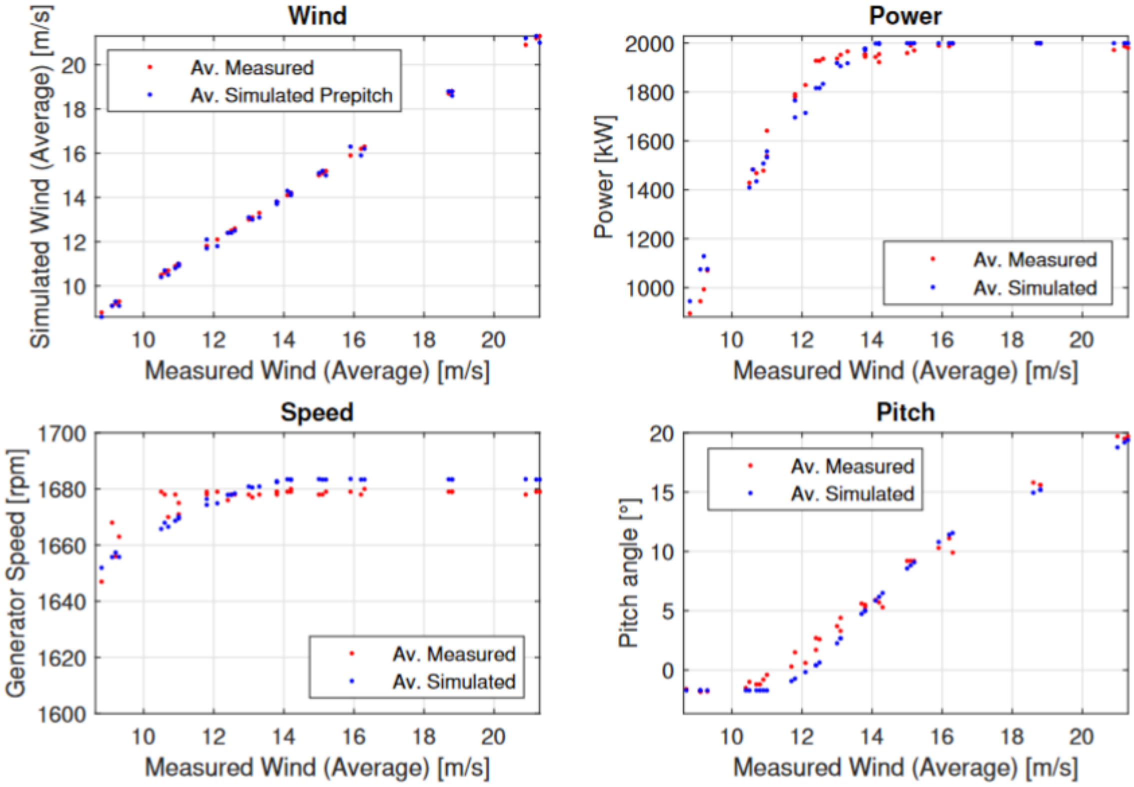

Figure 19: Preliminary results of 13 validation periods [21].

3.4 Expansion of the VPP for green hydrogen production

Hydrogen (H_2) is foreseen to become a central pillar in the decarbonisation of fossil-intensive energy sectors. Recently, the production of H_2 gained momentum in many industrialised countries as it offers solution on how to offset the use of fossil fuels, e.g., in shipping or aviation. In the context of islanded systems, the production of H_2 is a crucial element to further increase the independency of the energy supply. This section presents the results of a techno-economic analysis of how to size an electrolyser system embedded in a multi-domain virtual power plant.

Based on numerical data from the 60/10 kV substation on the island of Bornholm, an optimisation model has been structured to address the investment decision into an electrolyser system while taking into consideration electrical and thermal supply-demand decisions, as well as the operating constraints of the units. The objective function of the optimisation model minimises the overall costs of the system, accounting for (1) operational costs, (2) the revenues for the sale of H_2 and electricity, and (3) the annualised investment costs for an endogenously determined electrolyser size. The operational costs comprise the marginal costs for water consumption in the electrolysis process, for grid consumption, biogas plant operation, and utilisation of the renewable sources at the substation. The revenues are composed of the sale of H_2 at a fixed rate, as well as of electricity at a dynamic spot price. The investment and replacement costs per MW installed size of the electrolyser systems are transformed into annual costs by a capital recovery factor depending on discount rates and lifetime of the system.

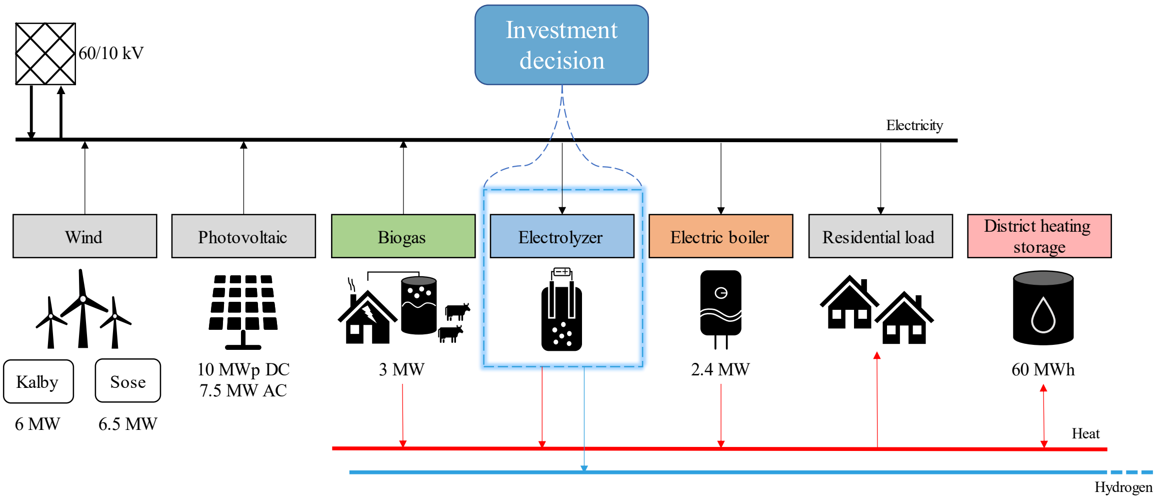

Figure 20: Illustration of the optimal sizing problem in a multi-domain virtual power plant [22].

Figure 20 sketches the single-line diagram of the 60/10 kV substation in Aakirkeby on the island of Bornholm that serves as basis for the research activities connected to the Use Case 5 of the INSULAE project. The focus of the analysis is on the power-to-H_2 extension of an existing set of coordinated resources. An electrolyser can produce H_2 via water electrolysis – a process in which water is split into hydrogen and oxygen molecules by applying a voltage between the anode and cathode of an electrolyser cell. Several electrolyser cells can be connected in series into stacks, while several stacks can in turn be connected in parallel. Hence, electrolyser systems for application in the MW-range are technically realisable. Following the prospects of the electrolysis process in PEM electrolysers, investment costs will fall exponentially over the next two decades [14] [23], and thus becoming more and more interesting from a business perspective. A PEM electrolyser needs in total approximately 55 kWh to produce a kg of H_2 via water electrolysis, including the compression of the output gas. H_2 has a higher heating value of 39.4 kWh per kg, hence the electrical efficiency of such a process adds up to 71.6%. It is assumed that an additional 15% of the input energy can be recovered as waste heat from the process and utilised for local and district heating purposes [13].

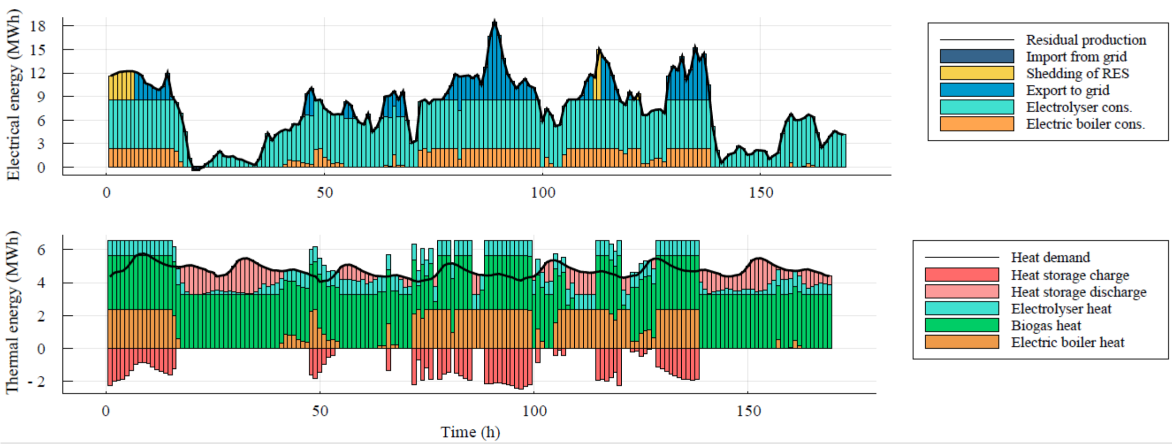

Figure 21: Dispatch decisions of the model from March 5 - 12, 2019.

Considering the techno-economic framework presented in [22] with the associated base data for the electrolyser system, the model invests in an electrolyser system with a nominal power of 6.2 MW. Figure 21 illustrates the electrical and thermal dispatch decisions of the model for one week in March 2019. The upper plot shows the allocation of the residual electrical energy (black line), calculated as the residual production from the wind farms, and the PV and biogas plants minus the inflexible residential electricity demand. It becomes clear that there is a frequent production surplus at the substation (positive residual energy). This energy can be utilised to a large extent in the electric boiler to produce heat or in the electrolyser to produce H_2. The spikes in the production are either sold to the grid or curtailed, depending on the level of the spot price.

Figure 22 (left) plots the resulting load duration curves of the different production (negative sign) and consumption (positive sign) assets at the substation. It can be noticed here that the electrolyser runs around 3000 hours of the year at full load. The corresponding yearly H_2 production that could be achieved by an electrolyser system of the determined size in this specific setting is 604.49 tons of H_2. Figure 22 (right) shows the daily sum of the H_2 production throughout the year 2019. From this production pattern, it can be noticed that there is a clear seasonality attached to the daily H_2 production. During summer, it is rather stable, due to the complement electricity production of the large-scale PV plant and wind farms. For the winter months, the H_2 production depends solely on the wind power production, hence the production varies more strongly. The average daily output at the substation is 1.66 tons of H_2 for the year 2019.

The flexibility introduced by the electrolyser has beneficial effects on the energy management of a multi-domain VPP. The electrolyser system not only acts as a valuable flexible load on the electrical side, but also opened for additional revenue streams as well as supplemented the other components in fulfilling the district heating demand at the substation. When deciding on specific electrolyser sizes, it is thus a crucial requirement to take the system perspective into consideration.

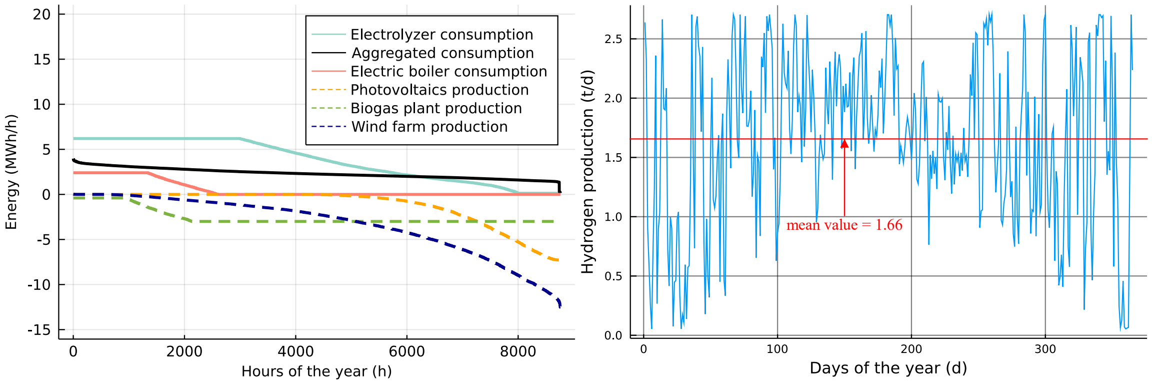

Figure 22: Duration curves (left) of the different production (negative sign) and consumption assets (positive sign), and (right) daily hydrogen production during the year 2019.

Biogas upgrading possibilities by the utilisation of hydrogen

Biogas plants play a vital role in multi-energy systems since they provide – beside their co-generation of electricity and heat – the possibility of upgrading biogas to synthetic natural gas via a methanisation process. This section reviews the necessities and characteristics for an upgrading process at the biogas plant on the island of Bornholm from a pure energy perspective. This analytical investigation is based on the Sankey diagram depicted in Figure 23, based on data from Energinet [24].

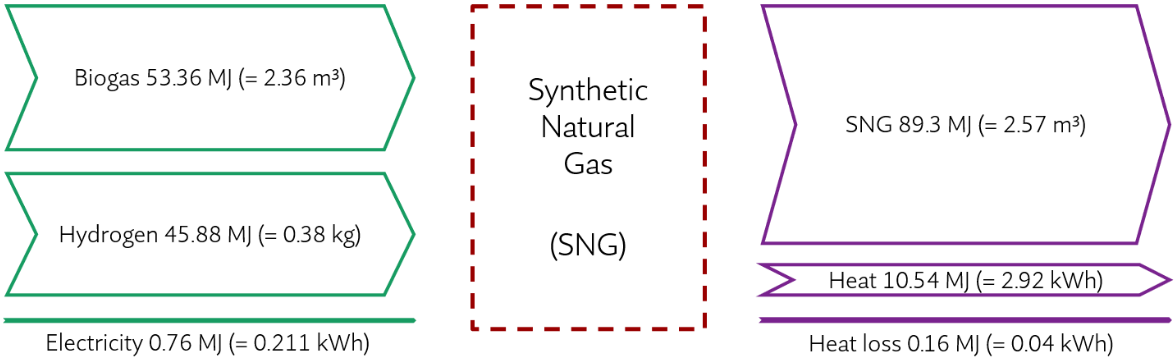

Figure 23: Energy balance for the methanisation process of biogas to SNG, based on [6].

For the month of September 2020, the biogas plant produced approximately 750,000 m^3 of biogas which comprise about 65% methane (CH_4) and 35% carbon dioxide (CO_2), neglecting other inconsiderable constituents. To transform all produced biogas to synthetic natural gas (syngas, SNG), the biogas (composed of CH_4 and CO_4) must be enriched with H_2 in an exothermal chemical reaction, see (1).

$$CH_4 + CO_2 + 4\,H_2 \rightarrow 2\,CH_4 + 2\,H_2O \tag{1}$$

For transforming the monthly production of 750,000 m³ of biogas, approximately 121 tons of H_2 as well as 67 MWh of electrical energy are needed to facilitate the SNG process illustrated in Figure 23. The production of 121 tons of H_2 requires in one month 6655 MWh of electrical energy, assuming an efficiency of 55 kWh kg H_2 in an electrolysis process [13]. This electrical energy needed corresponds approximately to a constant power requirement of 9.2 MW. An electrolyser of this size will hence be required to be able to produce all the H_2 needed for the upgrading on-site.

Following the illustrated Sankey diagram, a total amount of 815,929 m³ of SNG can be produced out of 750,000 m³ of biogas. Assuming an energy content of 9.97 kWh/m³ CH_4 and hence an energy content of 6.5 kWh/m³ biogas, the total energy that can be retrieved from the monthly biogas production of 750,000 m³ is 4875 MWh. This corresponds to the energy required for running the biogas plant at an average 95% of nominal power throughout the whole month. The energy content of 815,929 m³ CH_4 amounts to approximately 8135 MWh. Of this, only 62.7% could be utilised in the generators if they run at 100% of the nominal power for the whole month. Hence, the remaining 37.3% (3,034 MWh, 304,349 m³) of the CH_4 production can be used either for transportation or other energy requirements. It is noteworthy here that the energy conserved in the CH_4 that can be produced over the month of investigation is less than 50% of the energy needed to produce the H_2 used for the conversion. Moreover, the energy requirement of the electrolyser is three times the nominal power of the generators of the biogas plant. To this end, it would be important to couple the biogas plant with surrounding large-scale renewable energy sources such as WFs or PV parks. When the substation is overloaded, the renewable excess generation could be used for the electrolysis process. However, it is unlikely that this will be 9 MW straight throughout a whole month.

Since the island of Bornholm is not equipped with a gas grid, an alternative to the production of CH_4 would be the production of methanol (CH_3OH commonly referred to as MeOH). MeOH could be a potential motor fuel to offset the use of carbon-intensive diesel or gasoline for transportation, besides to the roll-out of electric vehicles. Especially the use of dimethyl ether (DME), which is a product that can be obtained from the dehydration of MeOH, has promising characteristics as it can be stored similarly to liquid gases such as propane at low pressures. The Danish Technological Institute reported that MeOH may be utilised with very little investment costs [25]. For the sake of this analytical discussion, the potential of producing MeOH is investigated by considering that the CO_2 of the combustion process of the biogas can be captured. The combustion of 1 m³ biogas releases approximately 1.8 kg of CO_2. With a monthly production of biogas of 750,000 m³ and presuming that the whole amount of biogas will be burned in the generators, a maximum amount of 1350 t CO_2 will be released within one month. Assuming that the necessary infrastructure is in place, the CO_2 can be captured and further processed. Analogously to the upgrading of biogas to methane, we can presume a 9 MW electrolyser to be installed on site. From CO_2 and H_2, MeOH can be produced following the exothermal chemical reaction as in:

$$CO_2 + 3\,H_2 \rightarrow CH_3OH + H_2O \tag{2}$$

A 9 MW electrolyser will produce about 120 t H2 in one month if powered at nominal rating. Given the mass balance visualized in Figure 24, 120 t H_2 can react with 856.25 t CO_2 which corresponds to capturing 63.43% of the CO_2 released from the burning process. Considering these input values, 625 t MeOH can be produced which corresponds with a density of 0.79 kg/l MeOH to 791,139 litres of MeOH. The energy that must be put into the process, considering already working conditions of the synthesis process, is again the energy needed for the electrolysis – approx. 6655 MWh. MeOH has an energy content of 16 MJ/l. Hence, the production value of 791,139 litres of MeOH holds 3516 MWh, being around 53% of the input energy.

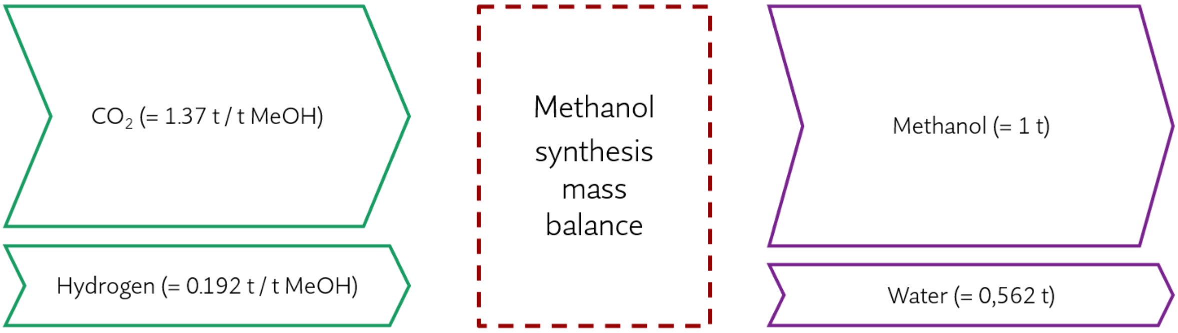

Figure 24: Mass balance for the conversion of carbon dioxide and hydrogen to methanol.

MeOH cars require, due to lower energy content, more methanol fuel than diesel or petrol cars. To give an idea, we consider now that a car running on 100% MeOH requires 10.6 l/100 km [25]. Hence, 791,139 litres of MeOH correspond to 7.4 mio. km. 6500 cars (around one third of the car population on Bornholm) with an average driving distance of 34 km/day [9] over 30 days will drive 6.63 mio. km. Thus, the MeOH production of the captured CO_2 from the burning process of the biogas plant would correspond to offsetting the conventional fuel consumption of a significant number of cars on Bornholm. However, three things must be kept in mind:

- The chemical synthesis plant that must be built for this conversion process is expensive. Costs for the process are decreasing.
- The technological advance of the chemical process is not taken into consideration. This analytical investigation is done pure from an energy perspective.
- It must be questioned what the envisaged application of MeOH in terms of energy efficiency is. For cars, battery electric vehicles are more efficient, considering the electrical energy needs of the H_2 production.

Another way of seeing the potential of methanol production from the biogas production in perspective is to consider the oil consumption of the ferry that connects Bornholm with the mainland of Sweden. The ferry is equipped with four equal engines of the kind MAN 20V 28/33D, each with a nominal power of 9 MW and a specific fuel consumption at full load of 193 g/kWh. The total engine power of the 112.6 m long and 30.5 m wide ferry is hence 36 MW. Considering an average 60% of the nominal power for the 80 minutes one-way trip, the energy consumption of one engine amounts to approximately 7.2 MWh. With the given specific fuel consumption for one engine, this value corresponds to 1.4 t fuel needed. Considering an energy density of 0.9 kg/l and all four engines, this would give a fuel consumption of 6176 litres for one crossing of 80 minutes at an average 60% of nominal power. The ferry goes approximately 4 – 7 times back and forth daily (depending on the season), signifying on average 11 crossings in total. The fuel consumption of 11 crossings would then correspond to 11 x 5.6 t = 61.6 t fuel per day. In a month, approximately 1850 t of oil are hence used for this seaborne transportation. As calculated above, around 625 t of MeOH may be produced from the biogas. Considering that MeOH with around 16 MJ/kg has a lower energy content than marine diesel (42 MJ/kg), approximately 2.6 times the amount of MeOH must be used in the ferries for the same energy requirement. This would result in a requirement of 4800 t of MeOH to substitute the monthly requirement of the ferry. The 625 t of MeOH produced for use in the ferries would hence provide only a share of 13%. Or in other words, the transportation with the ferries could be fuelled only in four out of 30 days in a month with the generated MeOH -- presuming that a one-to-one transition of fuel in the ferry's engines is possible.

3.5 Bornholm simulation model interventions

The VPP in Aakirkeby encompasses production form woodchips, straw, wind, sun, biogas, an electric boiler, a BESS, and an accumulation tank for district heating. The consumption side consists of electricity, heat, and transportation demands as well as grid losses.

Developed in previous research projects (e.g., ACES – Across Continents Electric Vehicle Services, 2017 – 2020 [26]), the Bornholm Energy System Simulation Model (BESSM) has been further extended to accommodate electrolysis and methanization processes. Moreover, the model has been customized to cover the VPP and its internal dispatch. Results from simulations of one year are described and discussed in the following sections, leading to the conclusions that the VPP in Aakirkeby shows a way for a 100% decarbonization of the island, by making use of the integrated management of local biomass-based energy production for the support of the electrical, thermal and transportation systems on Bornholm.

3.5.1 Energy planning objectives for the VPP

The BESSM includes the whole energy system of Bornholm, including production and consumption of among other things heat and electricity and energy for the transportation. An area on Bornholm is studied in UC5, where production capacity from renewables is particularly high, as well as a district heating system and a biogas plant situated (depicted in Figure 25). The characteristics of the main components marked in Figure 25 are listed in Table 10.

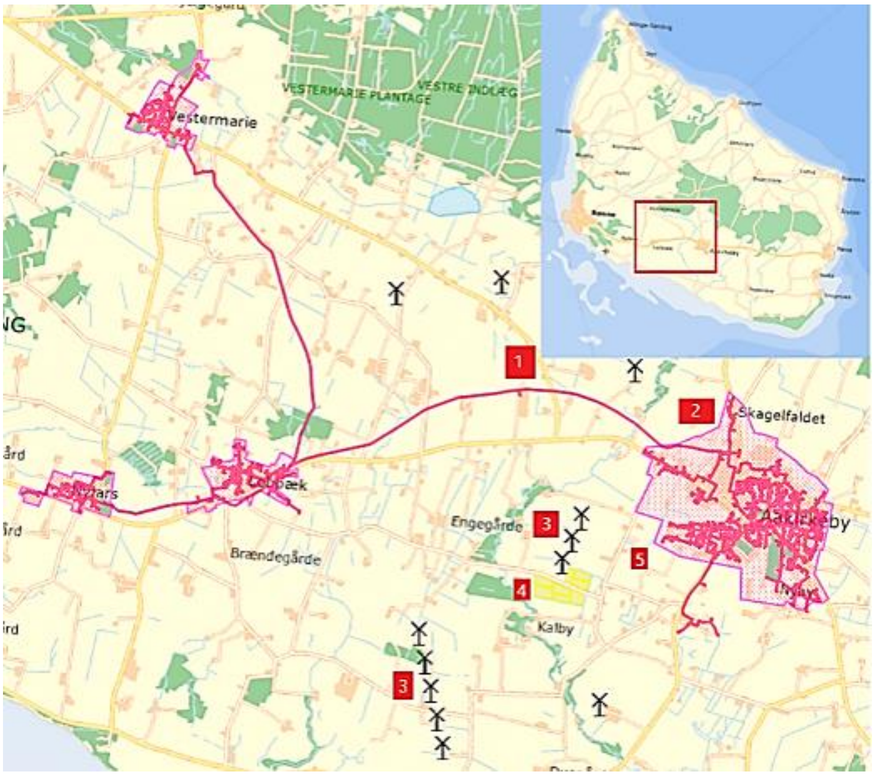

Figure 25: VPP location on Bornholm, showing the DHN, as well as placement of renewable energy sources.

Table 10: Main components in the VPP and characteristics.

Component	Input	Output	Control variables (Main)	Resolution
1 Biogas Plant				
- **Biogas production**	Biomass	Biogas	Infeed amount and characteristic	Weekly
- **CHP**	Biogas	Heat and Power	Throttle	5 min.
- **P2X** ○ **Electrolyzer** ○ **Methanization**	Electricity + Water Biogas + Hydrogen + Electricity	Hydrogen and Heat Electro-fuel (SNG) + Heat	Electricity Biogas and Hydrogen	5 min. 5 min.
2 District Heating system (Plant+Grid)	Weather	Heat	Temperature and windspeed	5 min.

3 **Wind Power**	Windspeed	Electricity	Windspeed and curtailment	10 min.
4 **PV Power**	Irradiance	Electricity	Irradiance and curtailment	10 min.
5 **Central Battery**	Electricity	Electricity	Service mode	5 min.
2 **Boiler**	Electricity	Heat	Service mode (variable load)	5 min.
EVs	Electricity	Transport/ Electricity	Service mode (variable load or balancing)	5 min.

Interventions in the Bornholm Simulation Model for UC5 implementation

The existing BESSM has been extended by new atoms for the electrolysis and methanization processes, and a logic to make all atoms for the resources work as a VPP. An overview of the VPP model in the BESSM is given in Figure 26. Peripheral components/atoms such as WTs, PV etc. are not displayed in the figure, but are part of the complete model. The overarching goal is to demonstrate how an island can provide a constant supply of energy to fulfil demand for heat and electricity, while at the same time produce alternative fuels for transportation through electrolysis and methanization. Each atom is configurable, and e.g., the battery can be made active or idle to identify its impact in the energy system.

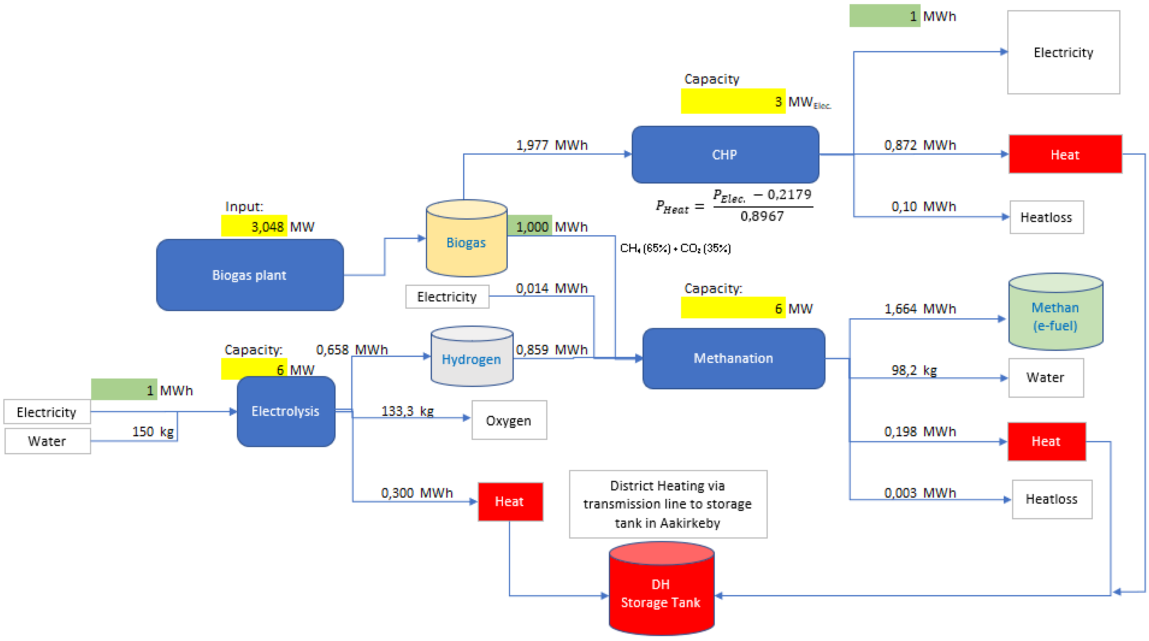

Figure 26: Overview of the VPP in the Bornholm Energy System Simulation Model - core part.

Heat is produced by the CHP, methanization process, electric boiler, and the district heating plant. Since the latter is dispatchable, there is no need for importing heat from outside the VPP.

Electricity in the VPP is primarily based on volatile renewable energy resources such as wind and solar PV. The logic for the CHP in the biogas plant was initially to produce electricity and heat on a continuous basis. In the VPP regime, the CHP is only activated in times when there is a deficit of electricity from renewables and the battery is empty at the same time. If production from renewables exceeds demand, as well as usable battery or electrolyser capacity, then electricity is exported out of the VPP. For islands without a submarine connection to a mainland, the excess electricity is unusable and can be considered as lost or cut off. If the CHP is unable to fulfil demand, electricity must be imported into the VPP.

Since heat is expected to be entirely covered by renewables (wood chip, and excess heat from the processes at the biogas plant), the following priorities are chosen to cover electricity demand: (1) renewable energy sources, (2) battery, (3) CHP, and (4) import.

The CHP is by nature not able to be treated as ‘a switch’, meaning that it is not able to be turned on and off just to cover a temporary deficit of, e.g., less than an hour. Therefore, import precedes if a deficit is less than 0.5 MW. The CHP’s minimum power is assumed to be P_{Min} = 0.75 MW, meaning export will presumably occur for CHP electricity generation. Since we assume Vehicle-to-Grid (V2G) being less deployed as charging technology than one-way, the possible support for grid balancing is ignored. The priorities for managing deficits in electricity are illustrated in Figure 27.

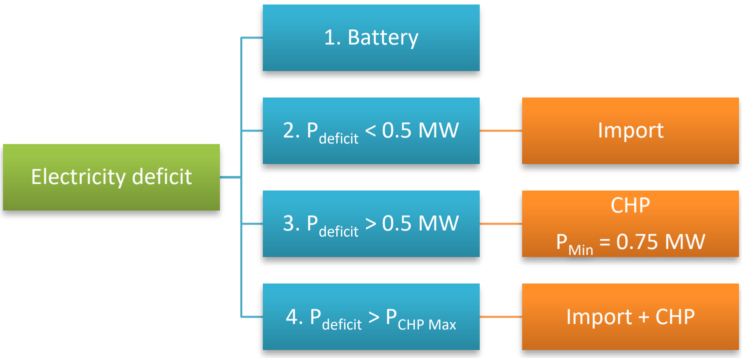

Figure 27: Priorities for deficit of electricity production.

If RES components are producing more than necessary to cover the demand, the following priorities are made for the surplus of electricity production: (1) battery charge, (2) methanization, (3) electrolysis, (4) electric vehicles, (5) electric boiler, and (6) export.

Heat demand is covered by the storage tank located at the district heating plant in close vicinity of Aakirkeby. Priority for managing deficits in the heat storage is given to the district heating plant for re-charging the storage tank. The tank also collects heat from the electrolysis and methanisation processes.

Roadmap for the intervention

As mentioned previously, the atoms are configurable, and in UC5 we have chosen a stepwise simulation approach to identify the system impact of single interventions as well as the combination of interventions. Figure 28 illustrates this incremental modelling approach. The rationale is that all activated interventions will simultaneously conceal the contribution of every single component towards the system's impact. An overview of all ten scenarios is presented in Table 11.

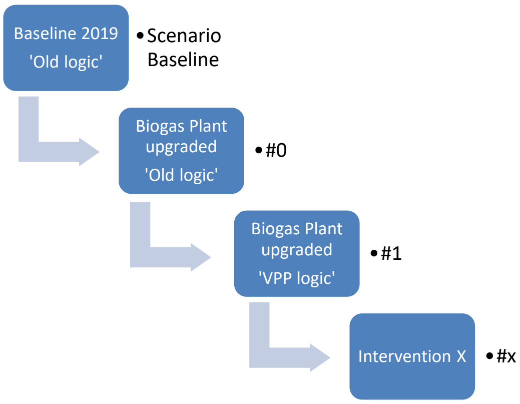

Figure 28: Stepwise approach for the interventions.

Table 11: Overview on atoms, scenarios, and stepwise change in the interventions.

Scenario	**Baseline**	**#0**	**#1**	**#2**	**#3**	**#4**	**#5**	**#6**	**#7**	**#8**
Descriptive description / Atoms	Baseline 2019 Biogas continously	Baseline+ Biogas plant Upgraded Continously	VPP BASELINE: Baseline+ Biogas plant Upgraded VPP logic	BESS alone	Electrolyzer+ Methanation alone	Electric boiler	BESS+ Electrolyzer+ Methanation+ Electric boiler	Weather data 2018	EV Smart 1 Way charging	EV Smart V2G charging
Weather data	2019	2019	2019	2019	2019	2019	2019	2018	2019	2019
Submarine cable CO_2 emission factor 2020 + DH Plant Aakirkeby incl. grid and customers	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019
Onshore wind turbines [MW]	12,5	12,5	12,5	12,5	12,5	12,5	12,5	12,5	12,5	12,5
Photovoltaics [MW]	7,5	7,5	7,5	7,5	7,5	7,5	7,5	7,5	7,5	7,5
Biogas CHP [MW]	2	3	3	3	3	3	3	3	3	3
Stationary Battery (BESS) - [MW] / [MWh]				1 / 1			1 / 1	1 / 1	1 / 1	1 / 1
Electrolyzer+Methanation [MW]					6		6	6	6	6
Electrical vehicles [No]	8	8	8	8	8	8	8	8	2477	2477
EV Charging* [dumb / Smart 1 way / V2G	dumb	dumb	dumb	dumb	dumb	dumb	dumb	dumb	Smart 1 Way	V2G
Electrical boiler [MW] impact VPP						2,4	2,4	2,4	2,4	2,4
Inflexible load	x	x	x	x	x	x	x	x	x	x

*) ACES charging logic

3.5.2 Simulation of VPP interventions

In this section, the scenarios will be unfolded subsequently and reviewed, some more explicitly than others. Demand for heat and electricity is kept constant in all scenarios. Demand for transport in terms of number of km driven is equally unchanged.

Baseline scenario

The Baseline scenario encompasses the components/atoms operating before the intervention of upgrading the biogas plant and converting to using the components in a VPP logic. The biogas plant is producing electricity as the main energy vector for selling, and heat as a by-product used for processes in the biogas plant, while the surplus is sold to the district heating system.

The results for the baseline scenario are shown in Figure 29, in which the accumulated output for the year 2019 from the Enterprise Dynamics simulations is illustrated as a Sankey diagram. The diagram is read from left to right. Input in terms of woodchips is generating heat (red) in the district heating plant of Aakirkeby that is together with heat from the CHP at the biogas plant aggregated in a storage tank (32,991 MWh at t_busbar). Total heat production sums up to 32,975 MWh, while total consumption is 32,991 MWh. The missing 16 MWh are supplied by dispatching heat from the storage tank. Similarly, electricity production is illustrated for each source with its corresponding production value in MWh. In total, 44,806 MWh are produced, while the electricity consumption is 19,429 MWh. The difference between the two is exported out of the VPP towards the electric grid. Net export amounts to 25,377 MWh. Transport is on the side-line since fossil fuels are not part of the simulations. Therefore, manual calculations are included in the data presented in Figure 29. In the baseline scenario, demand for transport is dominantly based on fossil fuels and only 20 MWh for EVs is powered directly from electricity.

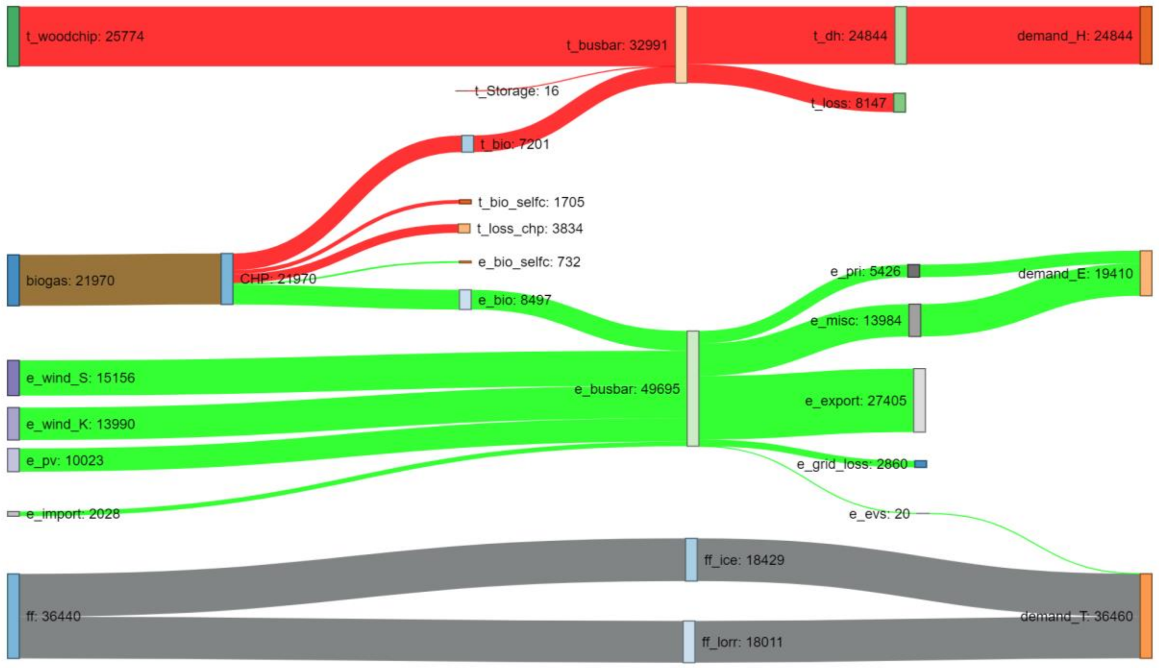

Figure 29: Sankey diagram for baseline simulation. All numbers are given in MWh/year.

Scenario #0 – upgraded biogas plant

In **Scenario #0** the gensets at the biogas plant are upgraded and biomass intake increased, while the operating logic is as before. An increase of the export or the amount of unusable electricity is anticipated.

The increased capacity and biomass intake of the biogas plant results in a significantly higher biogas production (more than double). Consequently, more than twice the heat input to the DH is simulated, leading to the fact that most of the heat demand is now supplied by the CHP. The electricity production from biogas almost tripled, leading to a 40% increase in electricity export, and a reduced electricity import 2028 MWh to approx. 73 MWh.

The heat production exceeds demand and is consequently simulated to be ventilated away (1462 MWh). Since the operating mode is like the baseline scenario, the logic is the same.

The biogas input 50,473 MWh is considered fixed in the rest of the scenarios. The simulations will show how much biogas is utilized in the VPP and how much is stored.

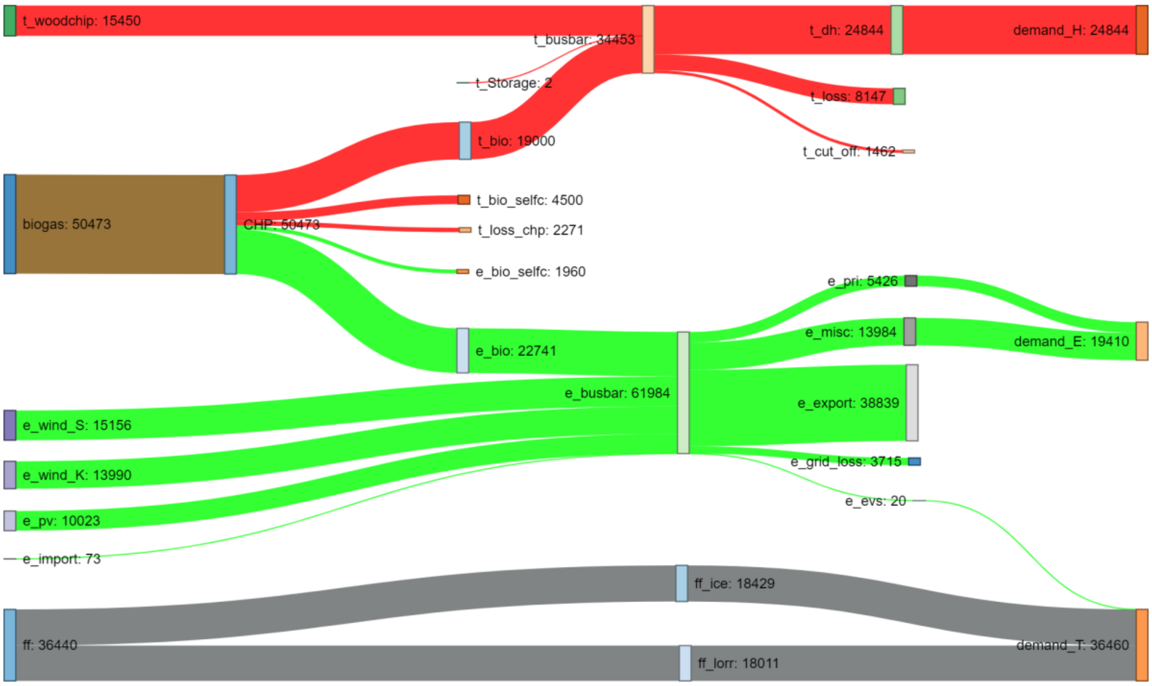

Figure 30: Sankey diagram for scenario#0 – upgraded biogas plant. All numbers are given in MWh/year.

Scenario #1 – introduction of VPP production logic

Scenario #1 differs from #0 with respect to the VPP logic implemented. The electricity production from the CHP is expected to be significantly reduced and biogas (consisting of methane and CO_2) will pile up, as it is not used as a fuel for the CHP or the methanization in this scenario.

Implementing this logic leads to the following results: The CHP runs only when there is no electricity production from wind and sun, and biogas is “stored” and can be used for decarbonizing transport – indeed the “stored” biogas energy, 50 GWh, is larger than fossil fuel for transport, i.e., 36 GWh. Electricity export is reduced by 45%, and import increased to 544 MWh.

Maintaining the same biogas production still requires unchanged amount of heat and electricity for the biological processes to take place. Heat from CHP creates only 819 MWh to self-consumption, although the need is 4500 MWh. The deficit of 2894 MWh is supplied by t_busbar. t_woodchip must hence cover the aggregated heat demand of 26,344 MWh + 2894 MWh = 29,238 MWh.

Electricity from CHP equals 436 MWh to self-consumption and the difference of 1524 MWh to supply the electrical self-consumption of the plant (1960 MWh) is supplied by the e_busbar. Electricity export (e-export) is reduced from 22,665 MWh by 1524 MWh to 21,141 MWh. It should be mentioned here that the presented Sankey diagrams are reflecting yearly aggregates and not hourly balances. Hence, if RES are not producing, the electricity import (e-import) will be increased instead of e-export reduced. In scenarios where the export is at its minimum, the deficit is covered by additional import. As heat from the biogas plant is reduced, additional heat from wood chip is needed, and exceeds the consumption in the baseline scenario.

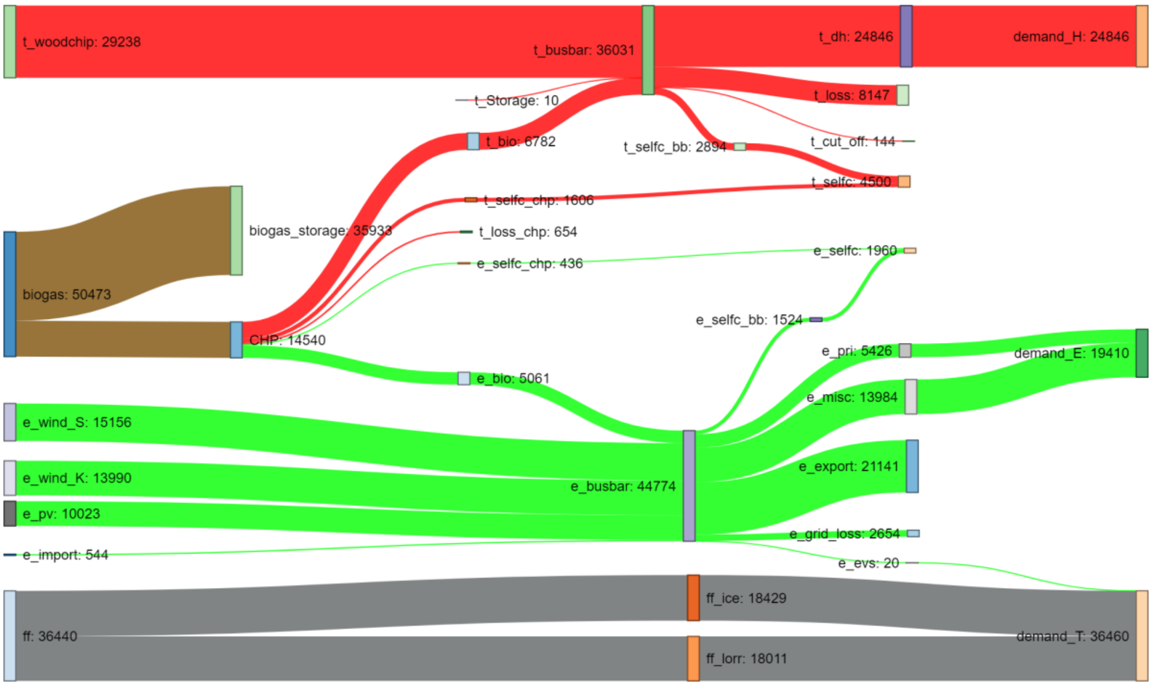

Figure 31: Sankey diagram for scenario#1 – VPP logic implemented. All numbers are given in MWh/year.

Scenario #2 – 1 MWh battery energy storage

Scenario #2 is coupling a battery energy storage system (BESS) and grid. Unusable electricity is anticipated to decrease, since the storage is charged when renewables are producing, and vice versa. The stationary battery is 1 MW / 1 MWh and will be installed in the autumn 2021.

In this scenario, the BESS contributes to balancing the power system. The BESS' impact is limited and reduces the export just above 2%. The charge and discharge processes are set with an efficiency of 90%, and the full equivalent cycles (FEC) per year are:

$$FEC = 453\ MWh \cdot \frac{0.9}{2 \cdot 1\ MWh} = 203$$

Comparing Figure 31 and Figure 32 shows only minor differences.

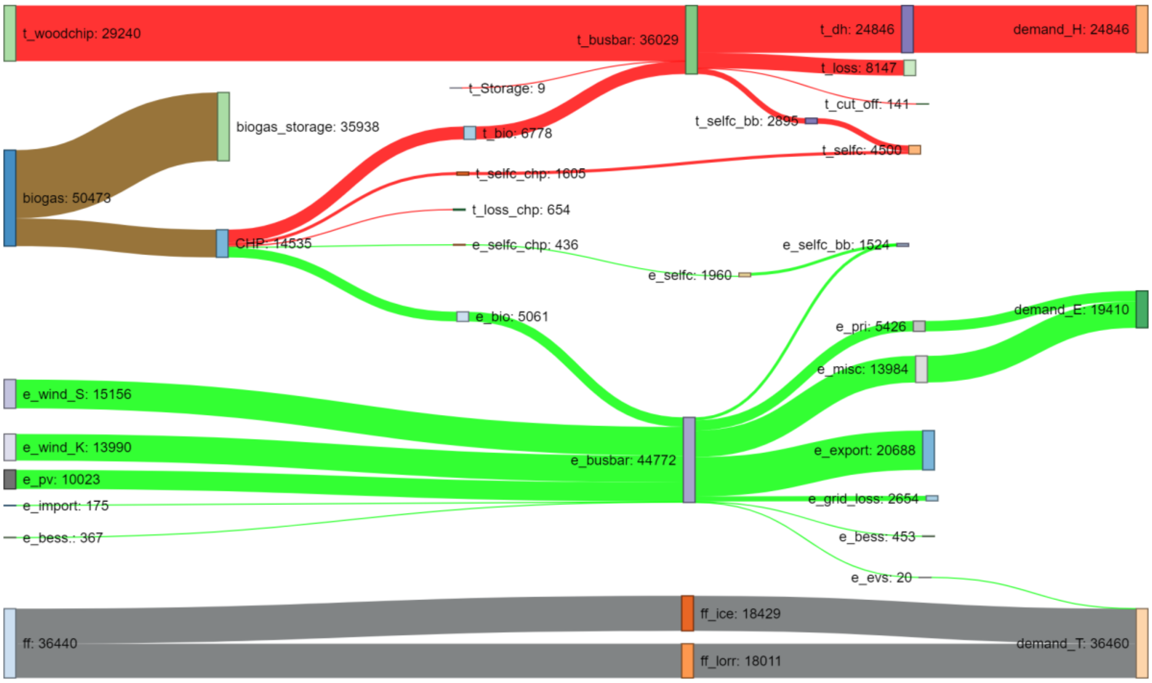

Figure 32: Sankey diagram scenario #2 – BESS implemented. All numbers are given in MWh/year.

Scenario #3 – electrolysis and methanization

Scenario #3 is activating the electrolyser and methanization which will minimize export/unusable electricity, and stored biogas will get lower compared to #1. The assumed electrolyser and methanization units are both 6 MW in capacity and are not implemented at the biogas plant at the current stage.

The CHP is partly producing heat and electricity for self-consumption and the additional heat and electricity is provided. Heat from woodchips is reduced by 18% compared to the baseline because heat from the electrolysis and methanization processes supplements the reduced heat from the biogas plant. Excess heat (1353 MWh) is ventilated into the air.

The electro-fuels generated from the methanization displaces the use of fossil fuels by cars and lorries.

As it appears in the Sankey diagram, the energy vectors are interacting; they form sector coupling and reduce export of electricity. Despite surplus of generated electricity from wind and sun, the VPP still imports electricity. The substantial amount of stored biogas could be used for removing import of electricity. Introducing electrolysis and methanization adds complexity to the VPP, as it is apparent from Figure 33.

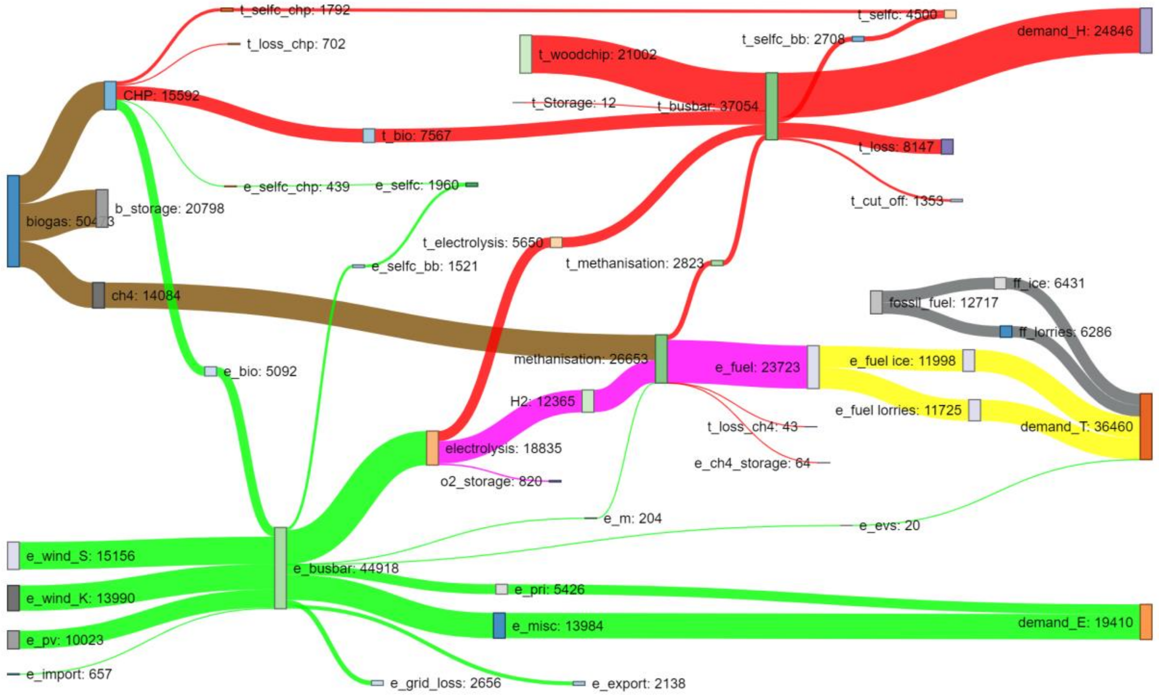

Figure 33: Sankey diagram of scenario #3 – electrolyser and methanization. All numbers are given in MWh/year.

Scenario #4 – electric boiler

Scenario #4 is introducing an electric boiler depending on the heat demand and heat storage capacity. It is expected to remove a bulk part of export/unusable electricity, but biogas will again pile up.

A comparison between baseline and #4 shows a reduction in the use of heat from woodchips by 27% and an export of electricity of 57%. The export is substantial, and it might be because the concurrency factor is low: Surplus of the electricity cannot be ‘fuelled’ in the electric boiler when demand for heat is zero and is therefore exported. A relatively high electricity production of RES is derived from PV and the production pattern does not fit well with the heat demand. Figure 34 indicates the flow of energy.

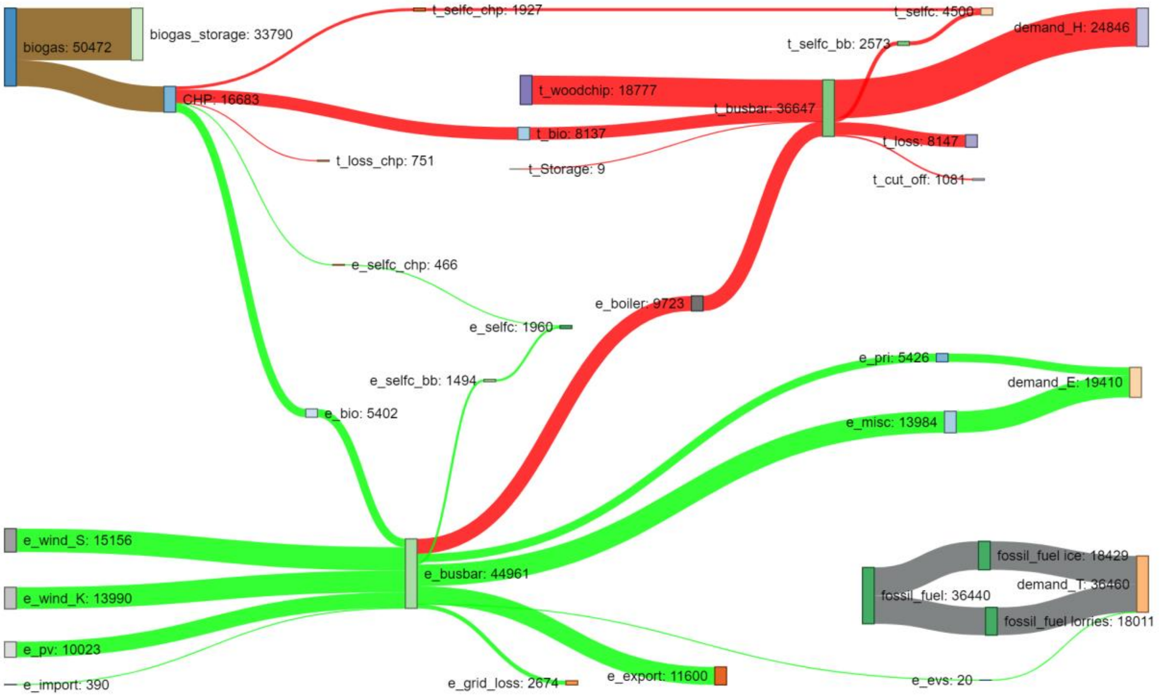

Figure 34: Scenario #4 – electric boiler. All numbers are given in MWh/year.

Scenario #5 – battery, electrolysis, methanization and electric boiler

Scenario #5 combines the BESS, electrolysis, methanization and electric boiler. It will observe the overall efficiency of the combination of the components mentioned in #2, #3 and #4. Definition of key performance indicators will help the task to assess the impact.

The biogas storage is still considerable and could be utilized for e-fuels if more RES were installed. The e-fuels covers 63% of the demand for fuel and contributes to a sustainable conversion of the transport sector. Heat from electrolysis, methanization and electric boiler reduces the use of woodchips by 24%.

The FEC of the battery are 261, e.g., 57 higher FEC than in #2.

The Sankey diagram presented in Figure 35 reflects the yearly values, but the hourly variation in production is hidden. When looking at the results in hourly resolution, the interplay between different production and storage technologies in the VPP to cover the demand can be examined.

Figure 36 shows how the power production covers the demand for electricity in **Scenario #5** on the 17th, 18th, and 19th of May 2019. Wind and PV play a major role, but also the CHP and battery contribute together with the electricity import to a smaller extent.

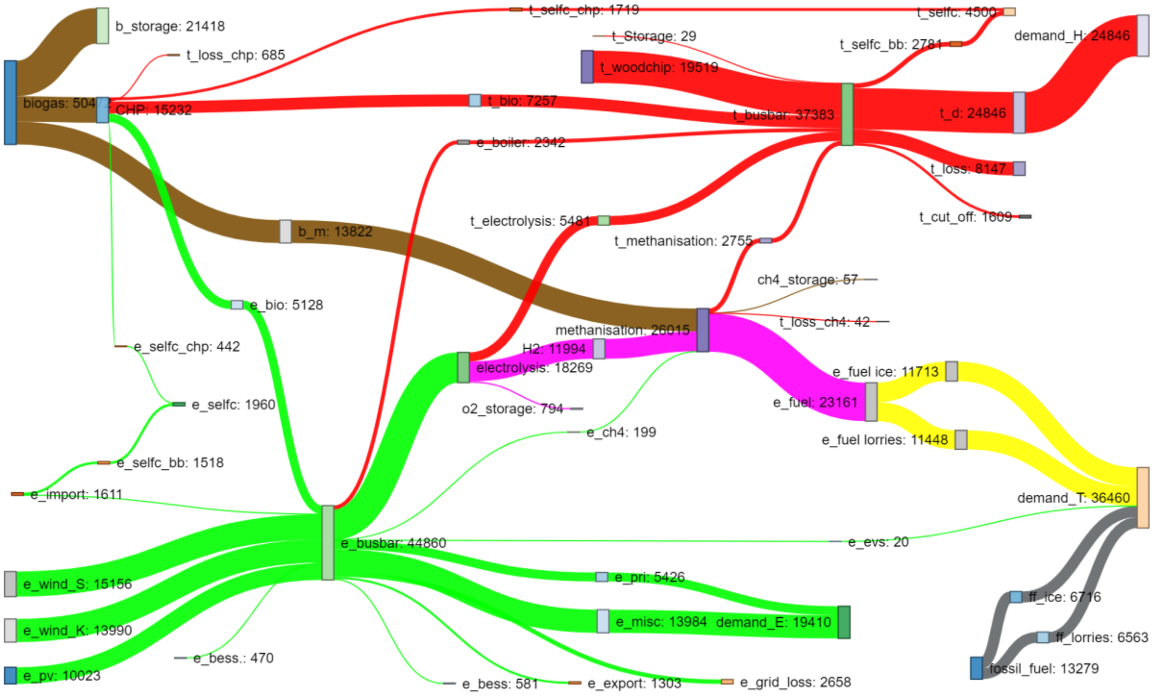

Figure 35: Scenario #5 – electrolyser, methanization, battery and electric boiler. All numbers are given in MWh/year.

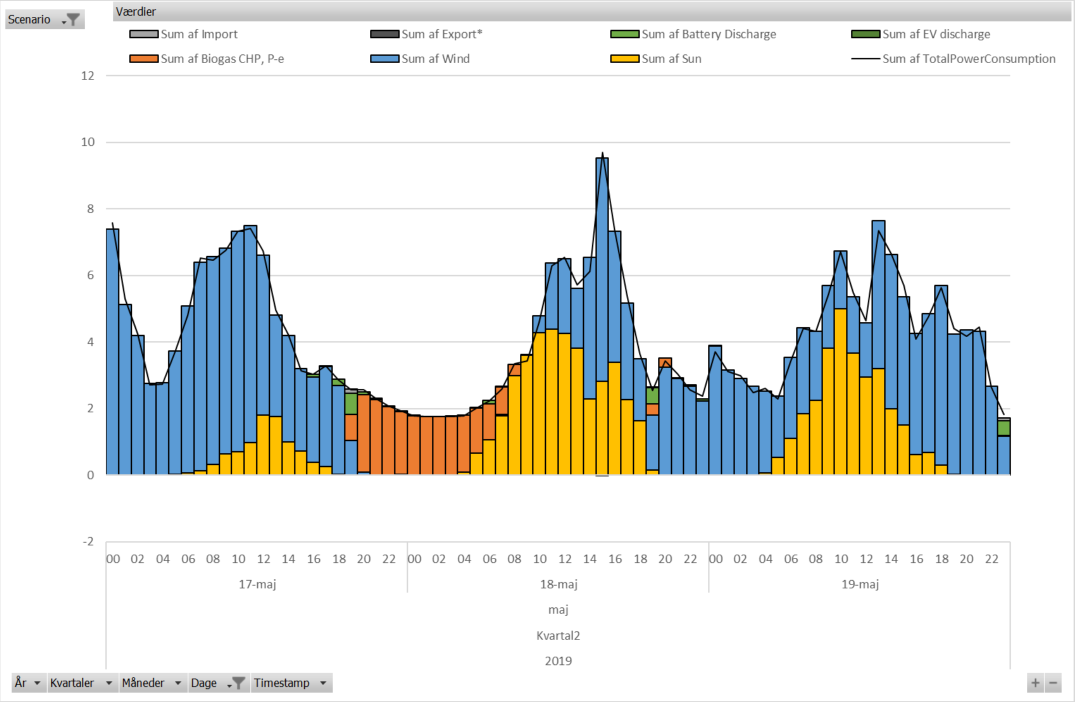

Figure 36: Scenario#5 – power production on 17th, 18th, and 19th May 2019 in fulfilling demand (black line).

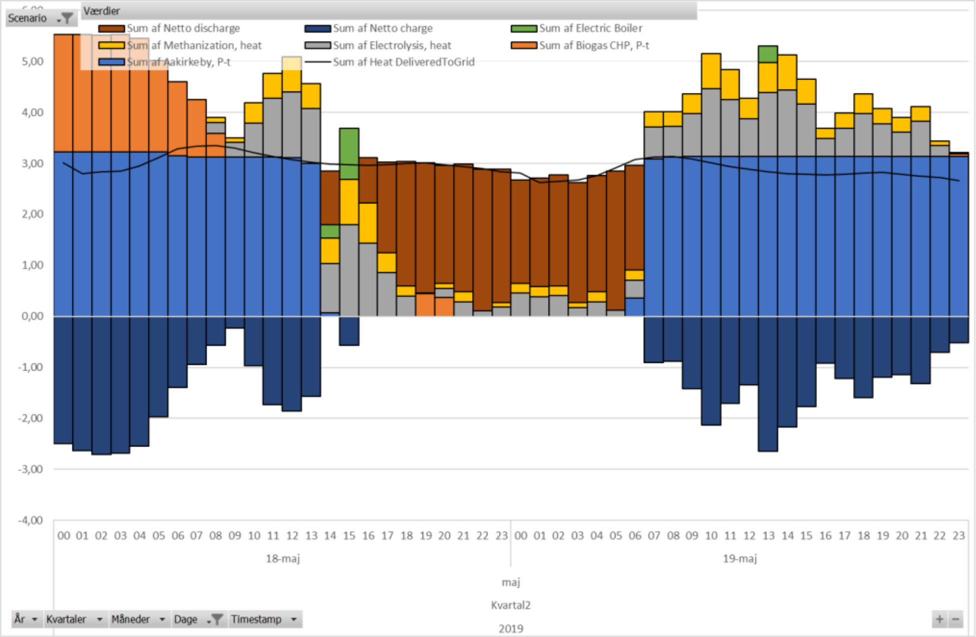

Figure 37: Scenario#5 – heat production on 18th and 19th May 2019 in fulfilling demand (black line).

Figure 37 shows the production of heat as well as how the demand is covered, and surplus is stored. The district heating plant produces in steady state, whereas heat from methanization and electrolysis depends on volatile renewable generation. The heat storage tank is a versatile component to absorb, and time shift the discharge of energy. The BESS is much smaller compared to the heat storage and has consequently a more sporadic utilisation.

Scenario #6 – weather sensitivity

In **scenario #6**, the weather data has been changed from the year 2019 to the year 2018 to see the sensitivity of the VPP scenarios to changing weather conditions. Depending on the distribution of production from the renewables, the impact from changing the weather data will be identifiable in the production of hydrogen and methane.

In 2018 the mean wind was 0.4 m/s less than in 2019 and it was sunnier, with +174 hours of sunshine, as reported in Table 12.

Table 12: Weather data Bornholm for 2018 and 2019, based on data from [27].

Year	Wind, mean	Sun
2018	5.0 m/s (DK 4.5 m/s)	2138 h (DK 1905.0 h)
2019	5.4 m/s (DK 4.6 m/s)	1964 h (DK 1729.3 h)

The change in weather has a direct impact on RES production: 6146 MWh less in 2018 compared to baseline. Even plus 174 hours of sunshine cannot outweigh the drop in mean wind speed of 0.4

m/s. Table 13 reports the yearly production values for the two wind farms and the PV park in the baseline scenario (2019) and the assumed values for scenario #6 (2018).

Table 13: Yearly RES production values in the baseline and scenario #6.

RES	Baseline 2019 [MWh]	#6 2018 [MWh]
Wind Turbine [Sose – 5 x 1.3MW]	15,156	11,608
Wind Turbine [Kalby – 3 x 2MW]	13,990	10,716
PV park	10,023	10,699
Total	39,169	33,023

Due to less RES, the production of e-fuel ratio drops by more than 18% compared to #5, covering only 51% of the demand. Else, the diagram in Figure 38 is quite similar to Figure 35.

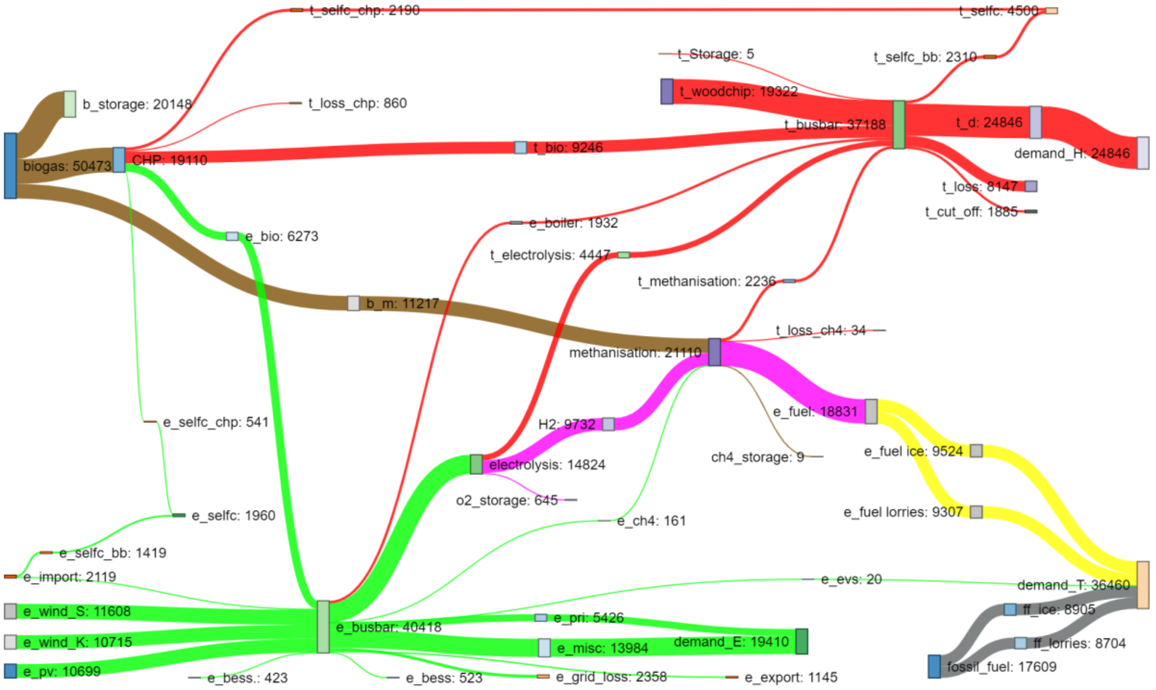

Figure 38: Scenario #6 – 2018 weather data. All numbers are given in MWh/year.

Scenario #7 – all cars converted to EV

All passenger cars are converted to EVs in **scenario #7**, which will leave less electricity for the electric boiler and the export of electricity.

The simulations show that the import of electricity increases. Transport is fully covered by fuel from electricity and e-fuels, and the total demand for transportation dropped by 32% because EVs are more efficient than ICE cars. In fact, the EV/ICE ratio is 3 times better, as calculated in Table 14. The overall savings in terms of energy are 73%.

Table 14: Assumed fuel and energy efficiency of fossil fuel cars and EVs.

Fuel efficiency ICE car	15 km/l
Calorific value gasoline	9.1 kWh/l
Energy efficiency ICE car	1.65 km/kWh
Energy efficiency EV	6 km/kWh
Energy ratio EV/ICE	3.64

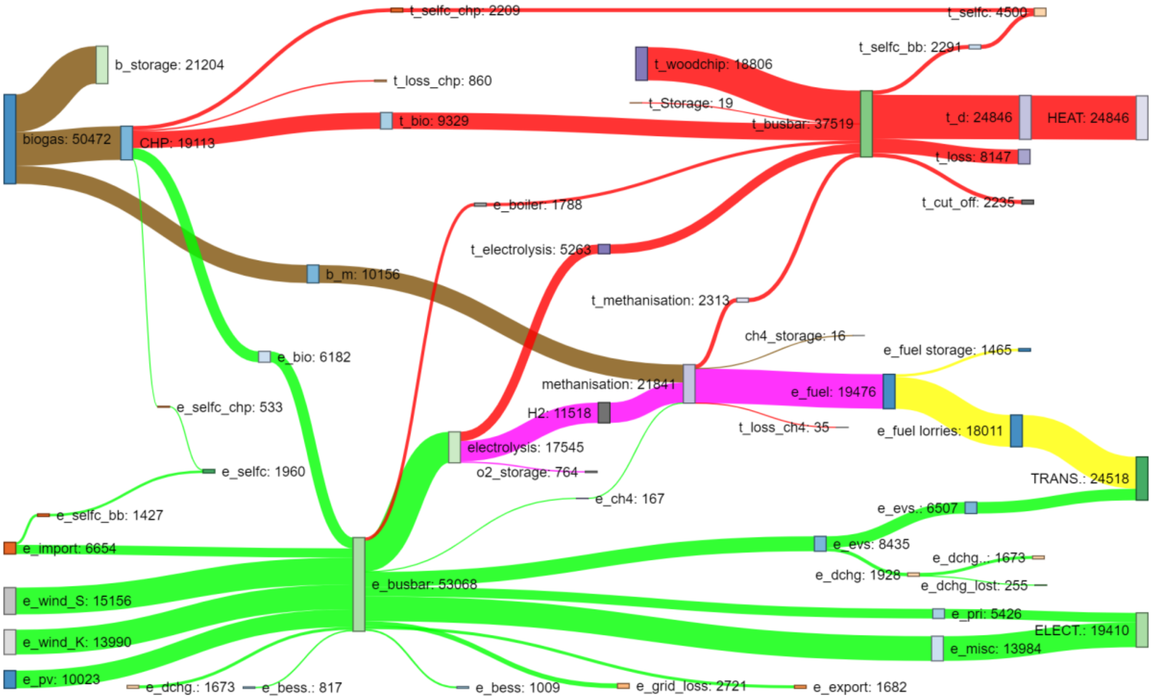

Figure 39: Scenario #7 – full deployment of EVs. All numbers are given in MWh/year.

Scenario #8 – Two-way EV-chargers

In **scenario #8** the EV-chargers are two-way, i.e., able to charge and discharge an EV. It should be noticed that not all EVs are designed for discharging, and moreover the charger itself is currently more expensive and supply is limited.

The results are not encouraging because import and export of electricity increase in this scenario.

The stationary battery is having 454 full equivalent cycles in **#8**.

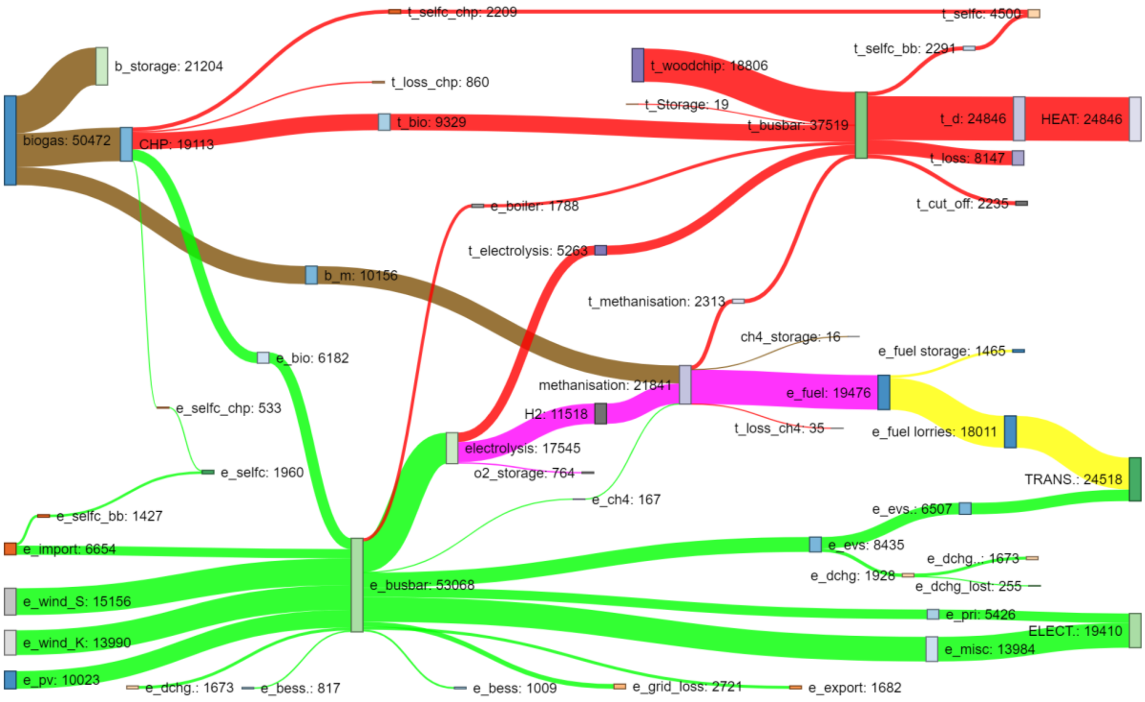

Figure 40: Scenario #8 – two-way chargers. All numbers are given in MWh/year.

3.5.3 Key performance indicators and direct impacts for UC5

Key performance indicators (KPI) were defined ahead of the simulations, as well as during the processing of the simulation outputs. An overview of defined KPIs and their application to the different VPP scenarios are given in the Annex – Key Performance Indicators.

The direct impacts for UC5 focus mainly on the amount of RES integrated and emissions saved by the increased utilization of the local bio-based system for the support of electrical, thermal, and transportation sectors. The project application listed that by the end of the project, the use of biogas will be increased by 40%, which leads to 5400 MWh/year increased RES supply, 3915 tCO_2/year emissions saved at investment costs of 136,000 €. The upgrading of the biogas plant enabled an increase of biogas intake of 28.5 GWh which is more than five times the expected RES integration in the VPP. The CO_2 emissions used in this report use physical CO_2 emissions reported by the Danish Energy Agency [28] and Aarhus University [29], as shown in Table 15.

Table 15: CO_2 emissions used in this report based on [28] and [29].

Fuel	CO_2 emissions (tons/MWh)
Biogas	0.303
Woodchip	0.403
Straw	0.360
Sea cable (Sweden – Bornholm)*	0.111
Fossil fuel	0.270

*) 2020 value. The CO_2 emission is declining every year because the ratio of renewables is increasing in the power mix.

Figure 41 presents the CO_2 emissions for each calculated scenario. In scenario #7, CO_2 from fossil fuel has been eliminated, and the total CO_2 emissions are the lowest of all scenarios.

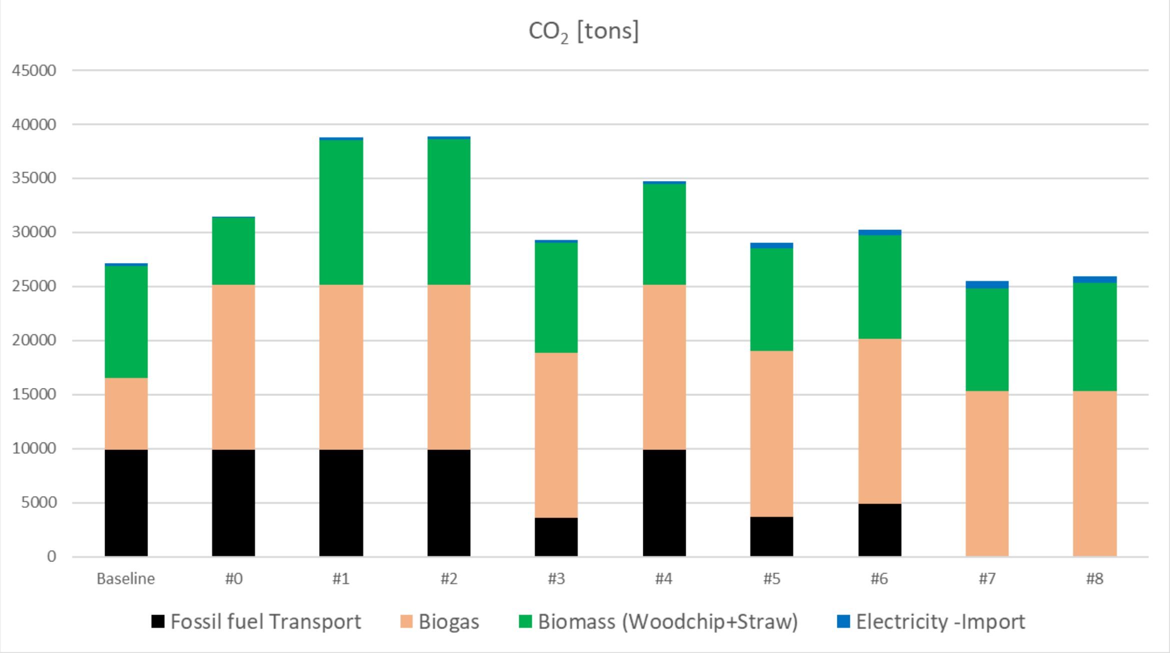

Figure 41: CO_2 emissions for each scenario.

Comparing the baseline and #7 gives 1631 tons of CO_2 savings in this VPP context, and transport is completely covered by e-fuels for lorries and electricity for EVs.

We find this scenario the most promising for a future VPP, because EVs are fully deployed, and smart one-way charging is most realistic for economic reasons. A V2G charger is expensive, and incentives need to be matured. If the VPP interacts with the rest of the Bornholm energy system, the number of EVs will increase and hence also the use of the biogas storage to produce additional e-fuels. As a side benefit, the cars converted to EVs save more than 13 GWh in energy savings because of a better energy efficiency in electric engines.

3.5.4 Summary of the Bornholm simulation model interventions

UC5 describes the VPP Aakirkeby, an energy system in a selected area of the island Bornholm. The presented scenarios simulate how to couple the thermal, electrical and transportation energy systems in this “island on the island” in a Virtual Power Plant setup. Hence, this use case describes an “island” with a large amount of electricity input from wind turbines and solar cells (up to six times the basic electricity consumption) and showcases how to use the surplus of electricity at any time, in the biomass-based district heating system, via electric boilers, as well as in the biogas plant via electrolysis and methanization processes producing fuel for decarbonizing transport and other fossil fuel consumptions, e.g., for industrial processes.

Scenario #0 – upgrading the biogas plant:

As in the baseline, the only production unit coupling the electricity and heat systems is the biogas CHP, but in this scenario the biogas plant is upgraded, as it has been done in 2019. The result of this is more than double input of heat input to district heating, so most of the heat input now comes from the biogas CHP, and the electricity production is almost tripled.

Scenario #1 – VPP logic is introduced:

Now the biogas CHP only runs when there is no electricity production from wind and sun, and most of the biogas, 50 GWh, is “stored”. This is more than the yearly fossil fuel demand for transport, 36 GWh. Electricity export from the VPP is reduced by 50%. As heat production from biogas is reduced, the heat production from woodchips now exceeds the heat production from the biogas plant.

Scenario #2-4 – introducing different technologies:

In these scenarios we introduce different technologies to couple the energy systems, and thereby increasing the means to balance the systems:

- In scenario #2, a large grid-integrated battery of 1 MW/1 MWh is introduced. It delivers electricity fast when production from sun and wind ceases, thus minimizing import of electricity.
- In scenario #3, an electrolyser to produce hydrogen for methanization of biogas is introduced. It utilises electricity, that would otherwise be exported, to produce more methane.
- In scenario #4, we introduce electric boilers on the heat plant, resulting in a reduced use of woodchips for district heating, and minimised electricity export.

Scenario #5 – the whole scope of technologies:

After exploring the different technologies one by one, we simulate all the technologies interacting as a “full VPP” in scenario 5. Surplus electricity is prioritized for: 1. Charging the battery, 2. electrolysis and methanization processes, and 3. utilization in electric boilers.

This scenario results in an almost completely balanced energy system, where all the produced electricity from wind and sun is used, and battery plus biogas CHP deliver the necessary electricity when there is no production from wind and sun. Approx. 23 GWh of methanised biogas is produced in a year from electrolysis and methanization of approx. 14 GWh of biogas. Together with an additional biogas production of approx. 30 GWh/y, this exceeds the demand from heavy transport of approx. 36 GWh/y. The surplus biogas can be used for decarbonizing other fossil fuel consumption, e.g., for industrial processes or ferries. Thus, scenario 5 shows a way for 100% decarbonizing of an island, by the integrated management of a local biomass-based energy production, supporting the electrical, thermal and transport systems in a Virtual Power Plant setup.

Scenario #6-8:

In these scenarios we explore the significance of different weather conditions (scenario #6), and the impact of converting all cars in the area to electric cars (scenario #7 and #8). However, the last two scenarios need fine tuning of the electric car logic, including V2G, to give a proper picture of the effect on the energy system.

The simulations, especially scenario #5, form a solid base for the next step to expand the VPP to the energy system of the whole island of Bornholm, using the BESSM and the Investment Planning Tool developed in the INSULAE project to produce an action plan.

4 CONCLUSIONS

Use Case 5 describes the energy components in Aakirkeby, Bornholm, in the context of a VPP setup assessing the coupling of the thermal, electrical and transportation domains for decarbonizing the island's energy system. This deliverable D4.9 gathers the key results and main conclusions of the performed simulation studies. The goal of these studies lies in assessing the flexibility potential of existing and prospective renewable-based components in different setups. To this end, simulation-based investigations have been performed to prepare for the upcoming demonstration activities within the Use Case, starting in Autumn 2021 and taking place until the end of the project in 2023. This deliverable concludes first activities directed at the design, energy management and control algorithms of the VPP structure. The main conclusions obtained from the simulation studies are:

- The biogas plant model can accurately describe the functioning of the biogas plant on Bornholm. With their flexibility in the gas storage and their fast-responding gas engines, biogas plants can provide grid services, such as frequency control. However, under the current regulatory framework in Denmark, these services only provide a marginal benefit for biogas plant operators.
- The integration of flexible resources, especially EVs via smart charging strategies, are worthwhile for enhancing the control of power flows at the substation level. Particularly, by modulating the EV charging current, fluctuations in wind power injections can be reduced while adhering to forecasted wind energy production. Surplus in renewable energy production can be used for EV charging needs.
- The impact of different interventions in the planning of the future renewable-based energy system of Bornholm is studied: Electrolysis and methanization of biogas offer beneficial possibilities for integrating different energy domains and utilizing the local bio-based energy potential. The recovery of process heat in the conversion steps is crucial for further energy system integration.
- However, hydrogen is a precious good that requires a high amount of energy to produce. Hence, it should be used only where no attractive alternative is available. Specific applications for hydrogen must be reviewed and further investigated.

Further research activities will revolve around the identification and provision of different grid services performed by the joint coordination of the components, as well as the enhanced energy management strategies. Although focusing mostly on simulation studies in Use Case 5, a series of demonstration activities are envisioned in the second half of the project to examine and define the flexibility of the existing technologies, e.g., in following and keeping power setpoints. The tests will be carried out until the end of the project in 2023.

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ANNEX – KEY PERFORMANCE INDICATORS

Key Performance Indicators (KPI) are defined ahead of the simulations, see Table 16. During processing the output from simulations, more KPIs were defined based on the results, shown in light grey.

Table 16: Definition of KPIs for the whole island of Bornholm.

KPI whole Bornholm	**Unit**	**Description**
Share of RES	%	RES penetration covering electrical and thermal needs
Share of DER	%	Share of DER in the energy mix
Final energy consumption	MWh	Total amount of energy produced on the island
Electrical consumption	MWh	Total amount of electricity consumed on the island
Thermal consumption	MWh	Total amount of thermal consumed on the island
Thermal Woodchip	MWh	Total amount of thermal produced on the island
Woodchips share of thermal consumption	%	Thermal woodchip / Thermal consumption
Local production	MWh	Total amount of energy produced locally
Electrical local production	MWh	Amount of electricity produced locally, if possible detailed by technology (wind, solar, etc.)
Electrical renewable production (E_{RES})	MWh	Amount of electricity produced by renewable plants, if possible detailed by technology (wind, solar, etc.)
Wind	MWh	
Solar	MWh	
Biogas	MWh	
Import of electricity	MWh	Amount of electricity imported from the continent
Export of electricity	MWh	Amount of electricity exported to the continent
Electrical production capacity	MW	Capacity, if possible detailed by technology (wind, solar, etc.)
Wind	MW	
Solar	MW	
Biogas	MW	
Import capacity	MW	~Infinite
Energy independency	%	Local production / Consumption
Electrical independency	%	Local electrical production / Electrical Consumption
Rate of renewable electrical production	%	Renewable electrical production / Electrical Consumption
Sum of methane from biogas and methanization	MWh	Potential for decarbonisation
Bio-fuel capacity	%	ΣCH_4 Storage and e-fuels in relation to fossil consumption for transport in Baseline
VPP ability to integrate electricity production	%	$(E_{RES} – E_{Export})/E_{RES}$
VPP capacity to minimize import of electricity in relation to consumption	%	$(E_{consumption} - E_{Import}) / E_{consumption}$
VPP capacity to minimize export of electricity in relation to consumption	%	$(E_{consumption} - E_{Export}) / E_{consumption}$
Full equivalent cycles BESS	No.	Battery contribution to balancing the grid

The KPIs for the VPP in Aakirkeby, Bornholm, are presented in Table 17 for all scenarios.

Table 17: KPIs for the VPP in Aakirkeby, Bornholm.

KPI VPP	Unit	Baseline	#0	#1	#2	#3	#4	#5	#6	#7	#8
Share of RES	%	157%	187%	200%	200%	190%	183%	184%	176%	166%	168%
Share of DER	%	69%	74%	76%	76%	89%	75%	88%	84%	95%	93%
Final energy consumption	MWh	91.737	92.578	95.945	95.945	94.625	95.613	95.849	94.956	83.300	83.360
Electrical consumption	MWh	22.290	23.145	23.608	23.608	22.472	23.598	23.606	23.207	30.012	29.272
Thermal consumption	MWh	33.007	32.993	35.897	35.897	35.713	35.575	35.803	35.308	35.278	35.303
Thermal Whoodchip	MWh	25.774	15.450	29.238	29.240	21.002	18.777	19.519	19.322	18.911	18.806
Share Woodchip of total demandHEAT	%	78%	47%	81%	81%	59%	53%	55%	55%	54%	53%
Local production	MWh	86.913	105.092	118.880	118.882	110.644	108.419	109.160	102.818	108.553	108.448
Electrical local production	MWh	47.666	61.910	44.230	44.230	44.261	44.571	44.297	39.295	45.266	45.351
Electrical renewable production Σ	MWh	47.666	61.910	44.230	44.230	44.261	44.571	44.297	39.295	45.266	45.351
Wind	MWh	29.146	29.146	29.146	29.146	29.146	29.146	29.146	22.323	29.146	29.146
Solar	MWh	10.023	10.023	10.023	10.023	10.023	10.023	10.023	10.699	10.023	10.023
Biogas	MWh	8.497	22.741	5.061	5.061	5.092	5.402	5.128	6.273	6.097	6.182
Import of electricity	MWh	2.028	73	544	175	657	390	93	700	3.849	5.227
Export of electricity	MWh	27.405	38.839	21.141	22.212	2.138	13.094	1.303	1.145	1.268	1.682
Electrical production capacity											
Wind	MW	12,5	12,5	12,5	12,5	12,5	12,5	12,5	12,5	12,5	12,5
Solar	MW	7,5	7,5	7,5	7,5	7,5	7,5	7,5	7,5	7,5	7,5
Biogas	MW	3,0	3,0	3,0	3,0	3,0	3,0	3,0	3,0	3,0	3,0
Import capacity	MW	60	60	60	60	60	60	60	60	60	60
Energy independency	%	95%	114%	124%	124%	117%	113%	114%	108%	130%	130%
Electrical independency	%	214%	267%	187%	187%	197%	189%	188%	169%	151%	155%
Rate of renewable electrical production	%	214%	267%	187%	187%	197%	189%	188%	169%	151%	155%
Sum of methane from stored biogas and methanization	MWh/y	-	-	35.933	35.938	44.521	33.790	44.579	38.979	42.021	40.696
Bio-fuel capacity	%	0%	0%	99%	99%	122%	93%	122%	107%	115%	112%
VPP ability to integrate electricity production	%	43%	37%	52%	50%	95%	71%	97%	97%	97%	96%
VPP capacity to minimize import of electricity in relation to consumptio	%	91%	100%	98%	99%	97%	98%	100%	97%	87%	82%
VPP capacity to minimize export of electricity in relation to consumptio	%	-23%	-68%	10%	6%	90%	45%	94%	95%	96%	94%
Full equivalent cycles Battery *	No.				204			261	235	313	454

*) Battery (2*1 MWh) chg/dchg 90% efficiency in both directions