PEAK

Paikallisen energiajärjestelmän kehittäminen Pohjanmaalla
Development of the regional energy system in Ostrobothnia

T1.2 Optimizing Smart Grid Flexibility and Resilience with Demand Response, Renewable Integration and Energy Storage

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TIIVISTELMÄ/ABSTRACT

This report presents the outcomes of Task T1.2 under Work Package 1 (WP1) of the PEAK (Pathways to Energy Autonomy and Knowledge-Based Flexibility) project, focusing on the flexibility potential and capacity assessment of sections of the regional electricity network of the company Esse Elektro-Kraft, 02_Porkholm and 03_Centrum, located in the municipalities of Pedersöre and Kauhava, Finland. Building upon the renewable energy potential mapping of Task T1.1, this study aims to analyze the current state of the electricity grid and evaluate the exploitability of flexibility resources such as demand response (DR), smart load control and battery energy storage systems (BESS).

The assessment uses real smart meter data and network topology information to model baseline consumption and simulate demand-side flexibility across different consumer categories. The analysis reveals that sectors such as farming, retail, residential heating, and public institutions possess substantial potential for load shifting, which could help reduce peak demand and alleviate grid stress. Financial savings from DR were found to be modest at the individual level but significant in aggregate.

In addition, hosting capacity studies and battery storage sizing were conducted to determine the technical feasibility of integrating distributed energy resources (DERs) without network reinforcements. Results indicate that mid-sized battery systems (600–2200 kW) could effectively manage peak loads and support voltage stability. A basic cost-benefit analysis also shows that such systems can deliver positive economic returns under current pricing assumptions.

Looking ahead, the report incorporates load and generation growth forecasts and provides strategic recommendations for DSOs, municipalities and policymakers. These include investing in DR programs, deploying strategically located storage and enabling local flexibility markets. Overall, this task lays a data-driven foundation for flexible, resilient, and sustainable grid planning, aligning with Finland's long-term climate and energy goals.

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1 Introduction and scope

1.1 Overview of the PEAK Project and WP1

The PEAK (Pathways to Energy Autonomy and Knowledge-based Flexibility) project is funded by the EU Just Transition Fund (JTF) and coordinated by the University of Vaasa in collaboration with Esse Elektro-Kraft Ab. It aims to facilitate a transition toward sustainable, resilient and decentralized energy systems across Ostrobothnia and South Ostrobothnia.

Work Package 1 (WP1) focuses on mapping renewable energy potential and assessing the flexibility of the regional electricity grid. It is designed to identify feasible and sustainable energy development pathways, particularly suited for regions that rely on local energy systems and networks. WP1 is subdivided into multiple tasks:

- T1.1: Mapping the renewable energy potential of the region. The task examines the renewable energy potential of the area under consideration through solar and wind power.
- T1.2: Mapping the Utilisation of the Electricity Network and Flexible Resources.
  This task is divided into five key focus areas:
  - Assessment of Customer Flexibility Potential
  - Impact of Renewable Energy and Electric Vehicles Adoption
  - Identification of Flexible Resources and Development Opportunities
  - System Reliability and Resilience Enhancement
  - Energy Storage Needs and Opportunities

1.2 Area under consideration

The geographical area covered in this project has been carefully defined to encompass the municipalities of Pedersöre in the region of Ostrobothnia and Kauhava in South Ostrobothnia, both located in western Finland. This area was selected based on the distribution footprint of the local electricity provider, Esse Elektro-Kraft, with a specific focus on regions where the highest concentration of its electricity users are located (Esse Elektro-Kraft Ab, 2025). This task focuses on the same geographical region as T1.1. The majority of residential, agricultural, and small industrial consumers served by

Esse Elektro-Kraft reside within the boundaries of these two municipalities, making them ideal for analyzing distribution network performance, energy consumption behavior, and the potential for integrating flexibility solutions.

By narrowing the scope to Pedersöre and Kauhava, the project gains a clear and focused field of operation that supports the effective execution of the technical and planning tasks outlined in Work Package 1 (WP1), particularly Task T1.2. This geographical delimitation not only facilitates access to detailed consumption data, smart meter readings, and network topology from a single distribution system operator, but also ensures that subsequent modeling, simulation, and planning efforts are contextually accurate and practically applicable. The defined area includes a mix of rural and semi-urban environments, offering a valuable diversity in energy usage patterns, infrastructure characteristics, and renewable energy potential.

Moreover, concentrating efforts within this defined boundary allows for meaningful collaboration with local stakeholders, municipalities, and energy users, ensuring that project outcomes are not only technically sound but also locally relevant and aligned with regional energy strategies. The selected area is the foundation for the analytical and planning activities carried out throughout the PEAK project. This structured and deliberate geographic focus enhances the credibility, replicability and impact of the project's results.

1.3 Scope and Objectives of Task T1.2

The main objective of Task 1.2 (T1.2) is to analyze the structure and performance of the local distribution networks and assess their ability to accommodate increased renewable generation and flexible loads. Key activities in this task include:

- Assessment of Customer Flexibility Potential:
  The current flexibility potential of customers, particularly controlled electricity consumption, is analyzed across different parts of the network. This includes evaluating existing control

systems and smart metering infrastructure, as well as identifying opportunities arising from future technological upgrades and devices.

- Impact of Renewable Energy and Electric Vehicles Adoption:
  An analysis will be conducted on how increased adoption of renewable energy sources and electric vehicles may lead to capacity constraints in the electricity grid (e.g., overloading of lines and distribution transformers). This will help identify future flexibility requirements in scenarios where network reinforcement investments are not implemented.
- Identification of Flexible Resources and Development Opportunities:
  Flexible resource potential, such as battery storage, will be mapped to specific locations within the grid. Special consideration will be given to the proximity of these resources to substations and distribution transformers, as location significantly influences their impact and effectiveness.
- System Reliability and Resilience Enhancement:
  The potential to enhance the reliability and resilience of the regional energy system will be evaluated. This includes the integration of renewable energy sources, flexible resources, and advanced monitoring and management technologies.
- Energy Storage Needs and Opportunities:
  The task concludes with an examination of the current and future needs for energy storage, as well as viable implementation options to support grid stability and flexibility.

This task focuses on the same geographical region as T1.1 (Pinilla De La Cruz, 2024), the municipalities of Pedersöre and Kauhava, served by Esse Elektro-Kraft's network.

1.4 Continuity and Relevance of WP1 Tasks

The work in T1.2 builds directly upon the renewable resource mapping of T1.1. While T1.1 confirmed the technical potential of solar, wind and biogas in the region, T1.2 seeks to answer:

- What is the current and future flexibility potential of customers in different parts of the network, based on control systems and smart meter solutions?

- How does increased use of renewable energy and electric vehicles impact grid capacity and flexibility needs without network reinforcement?
- Where are the most effective locations for flexible resources (e.g. batteries), considering grid topology and proximity to substations?
- How can system reliability and resilience be improved through renewables, flexibility, and smart grid technologies?
- What are the current needs and future opportunities for energy storage in the network?

The findings of T1.2 are pivotal for:

- Prioritizing grid upgrades or deferring them through flexibility.
- Developing cost-effective DER deployment plans.
- Informing municipal and utility-level energy strategies.

By integrating technical grid data, consumer behavior modeling, and financial analysis of DR and storage, this task provides an actionable bridge between renewable potential and real-world implementation.

2 Contextual background, Network Description and Baseline Analysis

2.1 Company: Esse Elektro-Kraft

Esse Elektro-Kraft (EEK) is a privately-owned Finnish energy company with a strong local presence and a commitment to renewable energy and sustainable power distribution (Esse Elektro-Kraft Ab, 2025). Owned by approximately 350 shareholders, EEK operates with a modest team of 13 employees and boasts an annual turnover of about 8 to 9 million euros. The company manages a distribution network that spans 1,055 kilometers, delivering electricity to around 3,800 connected users across voltage levels of 20 kV and 0.4 kV. The single line diagram of the full network is presented in figure 1. Its total annual electricity distribution is approximately 52 GWh and 38 GWh is sold to consumers. EEK's energy production portfolio includes three small-scale hydroelectric power plants—Värnå, Hattar, and Hanhikoski—with a combined capacity of 3.7 MW. In addition to its hydropower assets, EEK has diversified into solar energy with a 1.6 MW solar photovoltaic park, and also benefits from co-owned production assets, bringing the total production capacity to about 53 GWh per year. The company is actively expanding its renewable infrastructure, with a 1 MW energy storage facility currently under construction. EEK is at the forefront of addressing modern power sector challenges such as peak demand management, grid flexibility, and integration of renewable energy sources (RES) into distribution networks. The company emphasizes the importance of sustainability, affordability and security in its operations, supported by initiatives such as sector coupling, load shifting and user flexibility markets. Its 2024 energy profile shows high reliance on wind (43%) and hydro (41%) in its production portfolio, significantly above the national average. With a forward-thinking approach, EEK is poised to meet the rising energy demand from electrification and contribute to a low-carbon energy future by improving RES predictability, grid investments and optimal matching of generation with consumption (Esse Elektro-Kraft Ab, 2025).

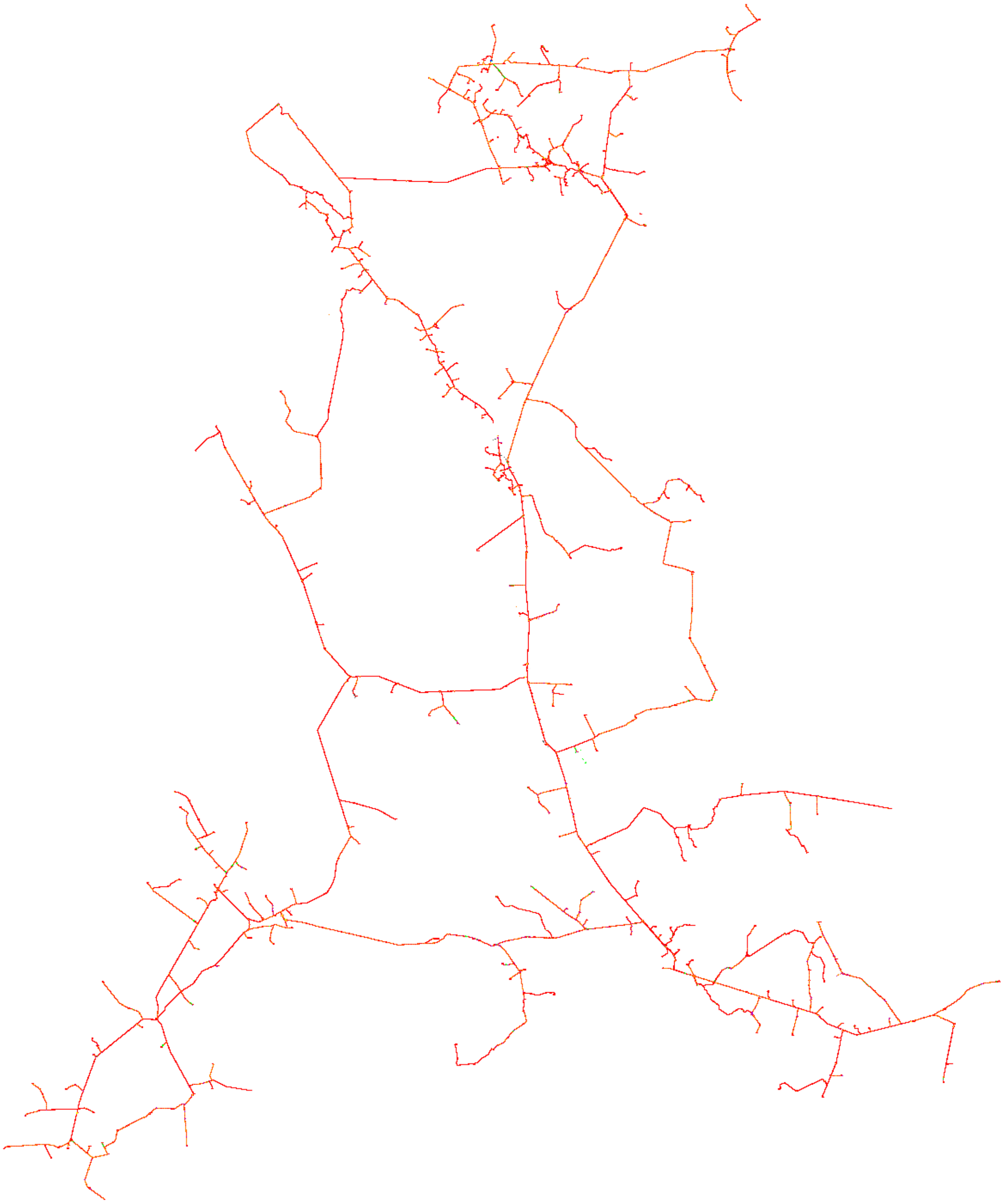

Figure 1. Single line diagram (SLD) of distribution network (Esse Elektro-Kraft Ab, 2025)

2.2 Overview of the Selected Distribution Networks

This section provides a detailed overview of the two low-voltage distribution networks selected for flexibility and capacity analysis in Task T1.2, 02_Porkholm and 03_Centrum, both operated by Esse

Elektro-Kraft. These networks were chosen due to their contrasting structural and load characteristics, representing a mix of rural and semi-urban energy consumption profiles. Their analysis offers a comprehensive understanding of how distribution systems in different physical and demographic contexts can benefit from targeted flexibility interventions.

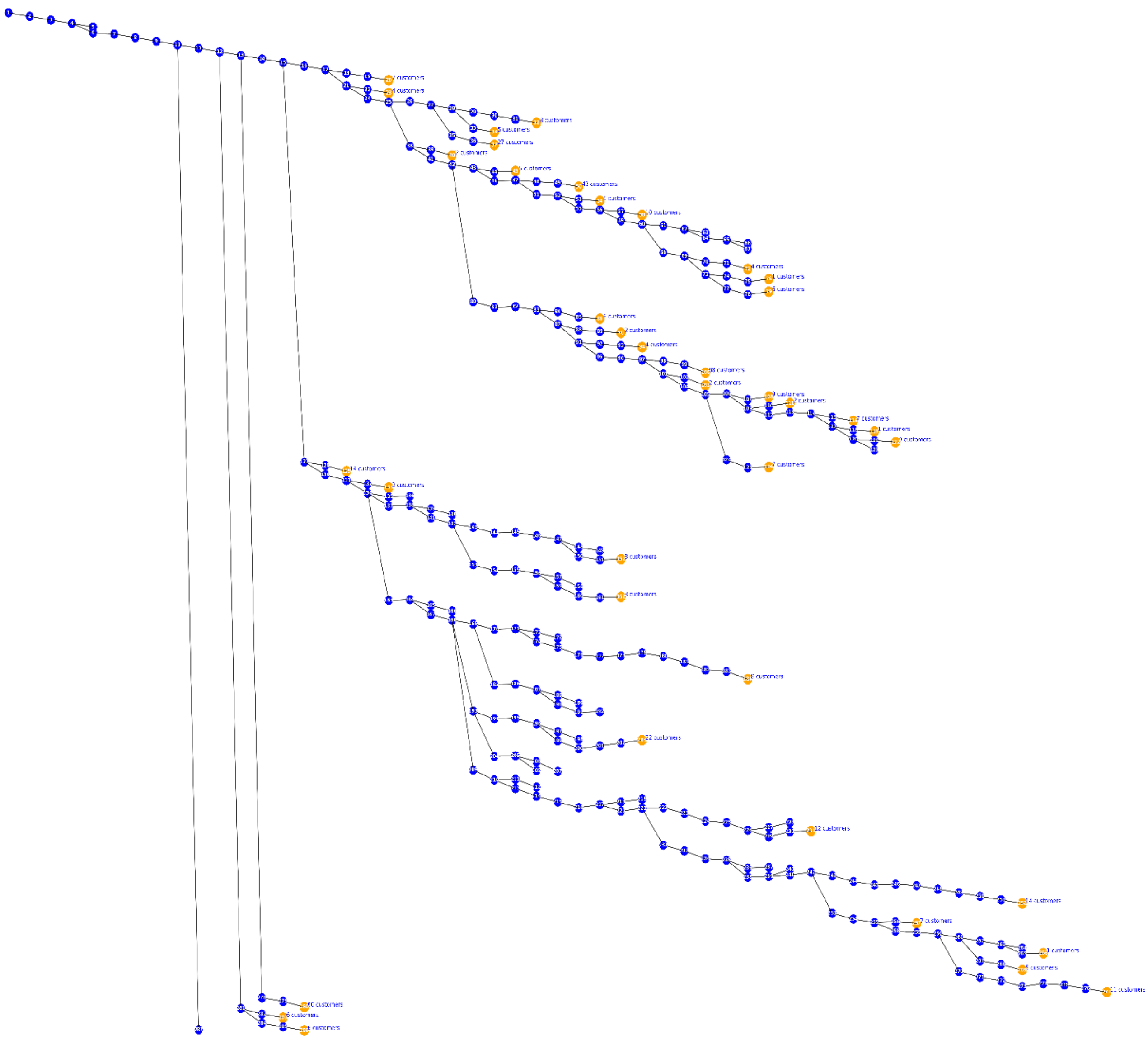

Figure 2. Single line diagram of 02_Porkholm

The Porkholm network is characterized by its rural structure, with 39 secondary substations, 287 nodes, a total network length of 55.39 km, and 277 customer connections. The single line diagram of the Porkholm network is presented in figure 2. Its annual electricity consumption is approximately 1953.11 MWh, with high seasonal variation largely driven by electric space heating in winter. By contrast, the Centrum network represents a more compact and urban setting, with 11 substations, 176 nodes, a network length of just 9.01 km, and 202 customers, consuming 1800.56 MWh annually. The single line diagram of the Centrum network is presented in figure 3. Despite its smaller geographic footprint, Centrum displays high peak demand during business hours, driven by commercial, public, and residential activities in a concentrated area.

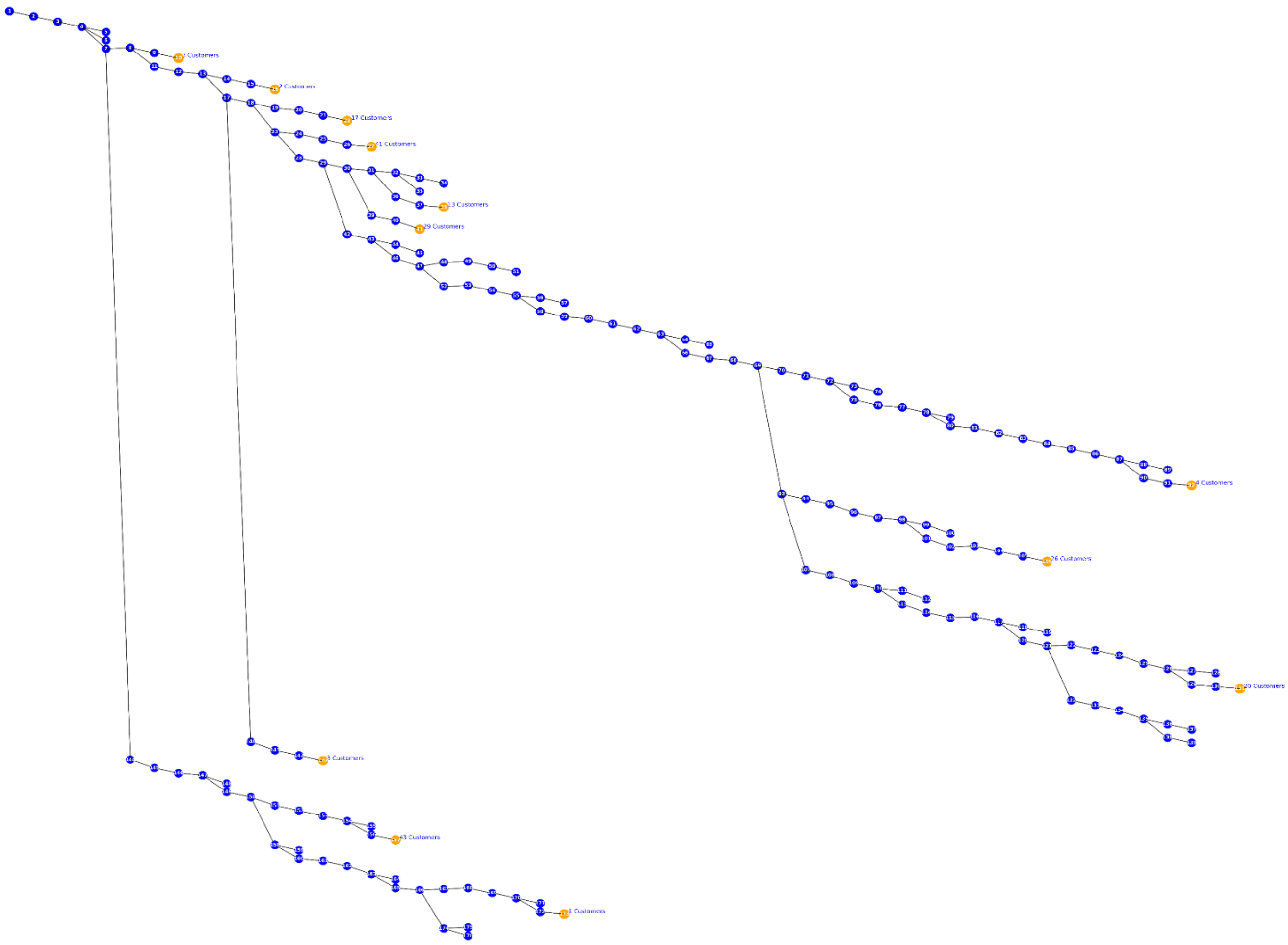

Figure 3. Single line diagram of 03_ Centrum

2.3 Data Sources and Methodology

This study uses a systematic and data-driven approach for modeling energy demand, battery storage allocation, heating optimization and demand response (DR) strategies across selected distribution networks. The methodology is structured around three major tasks and is informed by hourly-resolution consumption data spanning a one-year period. Smart meter data (hourly resolution), network maps, customer classifications, and line parameters are provided by Esse Elektro-Kraft Ab, while energy price data is sourced from ENTSO-E (ENTSO-E., 2025).

2.3.1 Data Sources and Preprocessing

All simulations are based on a comprehensive dataset containing one year (8,760 hours) of hourly electricity consumption data across different user categories within the selected networks. Data preprocessing involved filtering and segregating user and node-specific data for individual distribution areas, notably the 02_Porkholm and 03_Centrum networks. For node-level analysis (relevant to hosting capacity and battery allocation tasks), consumption data was matched to corresponding nodes within the network topology. For user-level analysis (relevant to demand response and heating optimization), customers were classified by consumer segment (e.g., households, commercial users), followed by profile clustering to generate aggregated load models that preserve representative demand patterns while reducing computational complexity.

2.3.2 Demand Response (DR) Modeling Methodology

The DR simulations were based on one year of hourly consumption data. Initially, users were segregated by network, then further grouped based on user type (e.g., residential, commercial). For each group, clustering algorithms were applied to identify similar usage profiles and aggregated load models were generated for representative clusters. The demand response model was then executed on these aggregated loads and the average DR impact was calculated to estimate the potential for load shifting.

To simulate realistic appliance behavior, a probabilistic appliance usage model was used in combination with a rule-based disaggregation technique. These models enabled estimation of the time-of-use patterns for key appliances which formed the basis for shifting peak demand to off-peak periods. DR shifting rules were designed for each customer segment, based on appliance flexibility, user behavior assumptions and observed consumption patterns. For instance, residential loads involving dishwashers or washing machines were assumed to be more deferrable compared to lighting or cooking-related loads.

2.3.3 HC and BESS Modeling

For the evaluation of Hosting Capacity (HC) and Battery Energy Storage Systems (BESS), one year of hourly electricity consumption data was utilized. The raw dataset was processed to derive node-wise load profiles for each selected distribution network, including 02_Porkholm and 03_Centrum.

To ensure robust and resilient planning, the analysis incorporated two distinct scenarios:

- Maximum Load Condition: This scenario considered the highest hourly demand recorded at each node throughout the year. It represents a worst-case stress test to determine the upper limits of the network's capacity to host additional distributed energy resources (DERs) or renewable generation without violating voltage or thermal limits.
- Average Load Condition: This was derived from the average hourly demand over the year for each node. It reflects typical operational conditions and is useful for gauging day-to-day flexibility.

Simulations were run under both scenarios to assess network performance, with a particular focus on identifying nodes most suitable for BESS deployment. For each node, the allocated peak demand (kWh) and the corresponding battery power capacity (kW) were calculated and ranked. Importantly, the best results for Hosting Capacity were observed under the maximum load condition, as it provided a more stringent and informative boundary for planning purposes. This condition allowed the identification of critical stress points in the network and helped optimize battery placement strategies to support grid stability and mitigate overload risks more effectively. By addressing the most demanding operating scenarios, the maximum load condition scenario ensured that the hosting capacity estimates were conservative yet realistic, providing valuable insights for grid planners and investment decision-makers.

2.3.4 Optimum Heating Demand Modeling

The optimization of heating demand was conducted using one year of hourly electricity consumption data. Similar to the DR methodology, users were first segregated by network and user type, followed by clustering of users with similar consumption patterns. Aggregated load models were then derived for each cluster and used as input for the heating optimization model.

This approach ensured that simulations reflected both diversity and commonalities in heating behavior across customer segments. Average results from the simulation were then extracted to represent the optimized heating load across each representative group, enabling evaluation of potential load reductions and improved thermal comfort levels through smarter control strategies.

2.4 Current State of Flexibility Infrastructure

An important part of the baseline analysis was understanding the current level of flexibility infrastructure already in place. Although both networks are equipped with smart metering infrastructure, there is limited active control of loads or centralized coordination of flexibility resources. However, several enablers exist: many homes and farms use electric heating systems with hot water tanks, which could support pre-heating or delayed operation; heat pumps are also common and can be programmed to operate flexibly; and some customer categories already respond informally to time-of-use tariffs (Carmichael et al., 2020). These characteristics indicate an underlying readiness for future demand response programs, though investment in automation and control systems will be necessary for full-scale implementation (Rahman et al., 2020a).

The hourly consumption data revealed that residential heating loads, especially in winter, dominate peak demand periods in both networks. In Porkholm, the spread-out nature of the network increases sensitivity to voltage drops and transformer loading. Centrum, while less vulnerable to such physical constraints due to its compactness, experiences localized congestion and peak demand clustering. These network-specific characteristics are critical in designing and locating flexibility resources such as battery storage and DR schemes.

Porkholm and Centrum offer two contrasting yet complementary cases for flexibility planning. Porkholm reflects the challenges of rural electrification, long radial feeders, and winter heating loads, while Centrum represents semi-urban load concentration and commercial usage patterns. Together, they provide valuable insights into how Finnish distribution networks can adapt to the energy transition through targeted, data-driven planning strategies. This baseline understanding sets the stage for the demand response analysis in Part 3 and the subsequent exploration of hosting capacity and grid reinforcement deferral in later sections.

3 Assessment of Customer Flexibility Potential

The integration of renewable energy sources into distribution networks introduces variability in both generation and consumption patterns, leading to increased challenges in maintaining grid stability, especially during peak demand periods (Rahman et al., 2020b). In this context, demand response (DR) emerges as a pivotal tool to enhance flexibility without requiring immediate infrastructure re-inforcement. This section presents a comprehensive analysis of the DR potential across various consumer segments within the 02_Porkholm and 03_Centrum networks, with the aim of identifying opportunities for peak load reduction, energy cost savings, and load shifting.

3.1 Concept and Approach

Demand response refers to the modification of electricity usage by end-users in response to supply conditions. This may involve reducing consumption during peak periods or shifting usage to times when renewable generation is more abundant or when grid capacity is underutilized. DR can be incentivized through mechanisms such as time-of-use (ToU) tariffs, real-time pricing, or automated load control systems that are integrated with smart meter infrastructure (Häseler & Wulf, 2024).

Table 1. Consumer type and number in 02_Porkholm and 03_Centrum networks

Consumer Type	Consumer Number
House, electric heating + hot water tank	289
House with heat pump	55
Apartment	43
Farming	27
Offices	7
Schools	1
Cottage	51
Retail store	2
Hotels	1
Industry	2
Garage	1
Total	**479**

To assess the DR potential in the selected networks, the analysis began with a classification of customers based on their load type and operational behavior. Consumers were divided into eleven categories: residential households (with and without heat pumps), cottages, farming, small offices, schools, hotels, retail stores, industry and garage (Esse Elektro-Kraft Ab, 2025). Consumer number according to consumer category is presented in table 1. Within these groups, consumption was further separated into two categories, appliance loads (irrigation pump, domestic equipment) and heating loads (Heating, ventilation and air conditioning - HVAC, electric heaters, hot water tanks, and heat pumps) (Table 2) (Carmichael et al., 2020; Pipattanasomporn et al., 2014; Wohlfarth et al., 2020). This categorization enables a nuanced analysis of flexibility, as heating systems typically offer more load-shifting potential due to thermal storage capacity.

Table 2. Demand Response participation between consumer groups

Consumer Type	**Demand Response Participation**	
	Appliances	**Heating**
House, electric heating + hot water tank	Washing, Dishwasher	Full Heating System
House with heat pump	Washing, Dishwasher	Full Heating System
Apartment	Do not participate in DR	Do not participate in DR
Farming	Irrigation Pumps	Full Heating System
Offices	Do not participate in DR	HVAC (Heating)
Schools	Do not participate in DR	HVAC (Heating)
Cottage	Washing, Dishwasher	Full Heating System
Retail store	Do not participate in DR	HVAC (Heating)
Hotels	Laundry	HVAC (Heating)
Industry	Do not participate in DR	HVAC (Heating)
Garage	Do not participate in DR	Do not participate in DR

The temporal aspect of the analysis was structured around a classification of the annual operation hours into peak and off-peak periods. For most residential and commercial consumers, peak hours were defined as the intervals between 07:00–10:00 and 16:00–21:00 on weekdays, aligning with high national demand and grid stress. Off-peak hours consisted of night-time periods, weekends, and daytime periods outside of peak times. Using hourly consumption data, simulation models estimated the amount of energy that could be shifted from peak to off-peak periods and calculated the associated cost savings using current electricity pricing structures. The analysis also accounted for pre-heating strategies, wherein heating is activated before the onset of peak periods, storing thermal energy for later use.

3.2 Segment Wise Results and Insights

The simulation results revealed diverse patterns of DR potential across customer types. Among residential consumers using electric heating and hot water tanks, peak shifting resulted in annual savings of approximately €23.43 per household and 5.8% reduction in overall energy cost. These savings are based on shifting around 4221 hours of annual peak usage to off-peak windows. In houses and cottages with the ability to pre-heat, cost savings were similar, around €23.23 annually, energy savings reached up to 196.27 kWh per year and 16.45% reduction in overall energy cost.

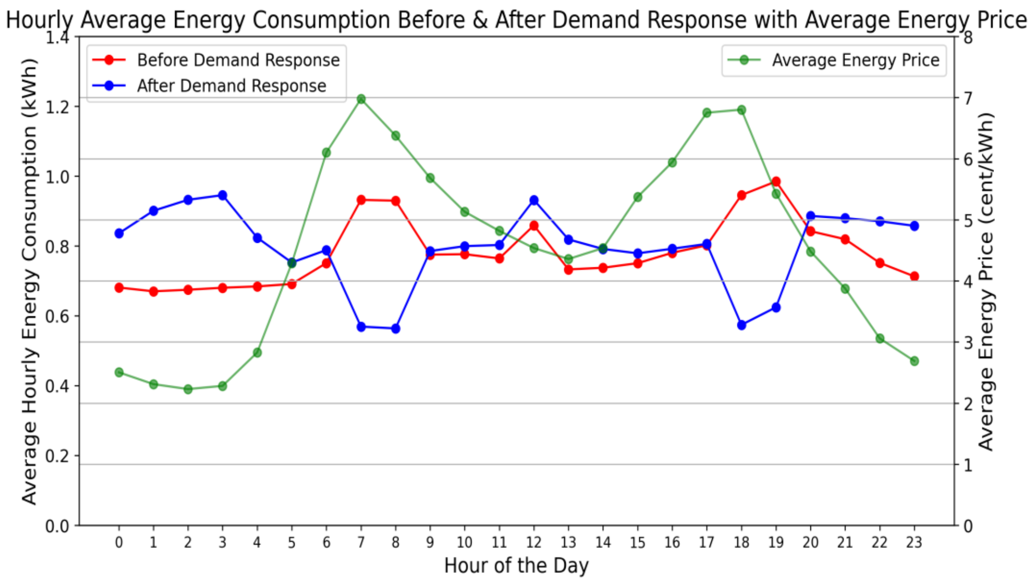

Figure 4. Hourly average energy consumption before and after appliance-based DR in residential buildings

These values demonstrate the latent potential in utilizing existing heating infrastructure in conjunction with simple automation strategies to achieve measurable financial and grid benefits. Figure 4 represents the hourly average energy consumption before and after appliance-based DR in residential buildings. When energy price is high, the load is shifted to off-peak time.

Consumers with heat pumps, increasingly common in modern Finnish households, showed a greater degree of flexibility due to their higher efficiency and programmability. For this group, DR simulations indicated savings of €38.49 on appliance loads (7.06% reduction) and €21.49 on heating (16.89% reduction), with a total energy shift of 185.11 kWh annually in heating alone. These findings suggest that heat pump users represent a high-potential group for future DR programs, especially when integrated with smart thermostats and demand-aware control systems. Figure 5 shows the hourly average heating power before and after a demand response (DR) strategy in residential buildings. The DR reduces heating power during peak price hours (7–8 AM and 5–7 PM) and shifts usage to lower-price periods. This helps lower energy costs while maintaining comfort. On the other hand, figure 6 presents monthly heating power consumption in residential buildings before and after demand response (DR) implementation. The DR strategy consistently reduces heating demand, especially during colder months.

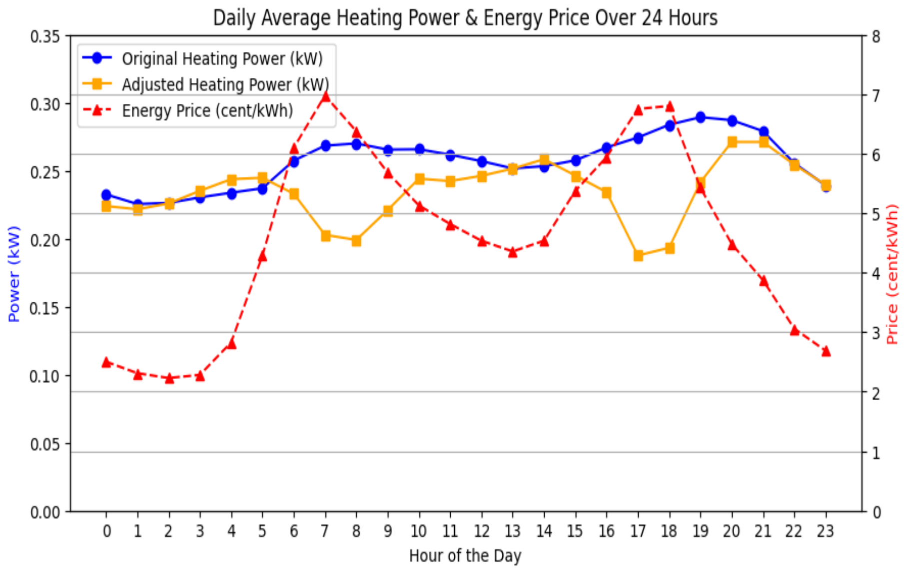

Figure 5. Hourly average energy consumption before and after heating-based DR in residential buildings.

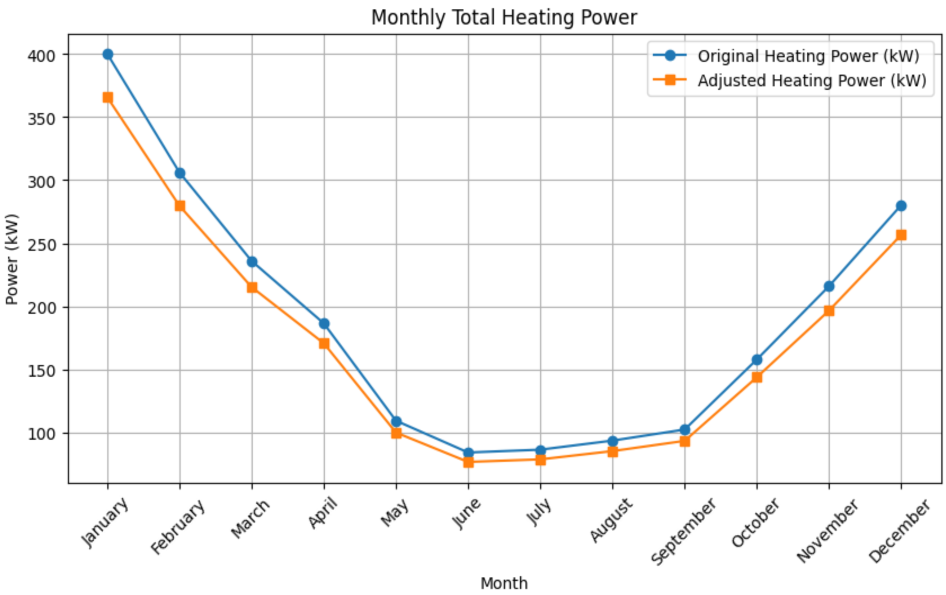

Figure 6. Monthly energy consumption before and after heating-based DR in residential buildings.

The agriculture sector, often overlooked in DR studies, emerged as a strong candidate for flexibility. Farming consumers saved €48.43 on appliance use (14.42% cost reduction) by shifting loads such as irrigation pump. For heating applications in the agriculture sector, cost savings reached €41.03. In total, over 707.46 kWh of appliance energy was shifted in this sector.

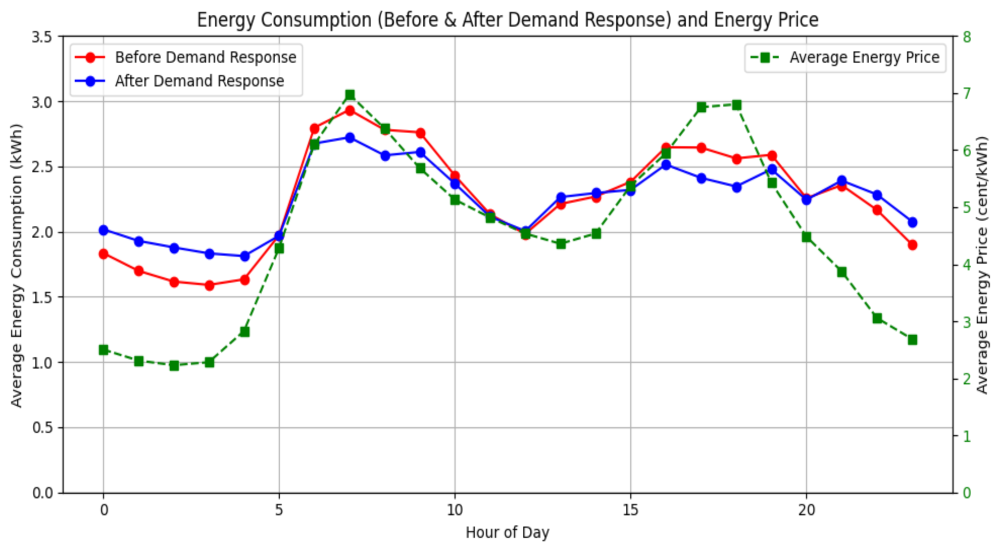

Figure 7. Hourly average energy consumption before and after appliance-based DR in farm

Given the repetitive and scheduled nature of agricultural processes, this sector offers substantial potential for automated DR solutions, particularly when supported by digital monitoring and control infrastructure. Figure 7 shows the hourly average energy consumption on a farm before and after applying appliance-based demand response (DR). The red line indicates higher consumption during peak price periods, while the blue line shows reduced usage after DR. The green dashed line represents average energy price, peaking around 7–8 AM and 5–6 PM. DR effectively shifts or reduces load during high-price hours to cut costs.

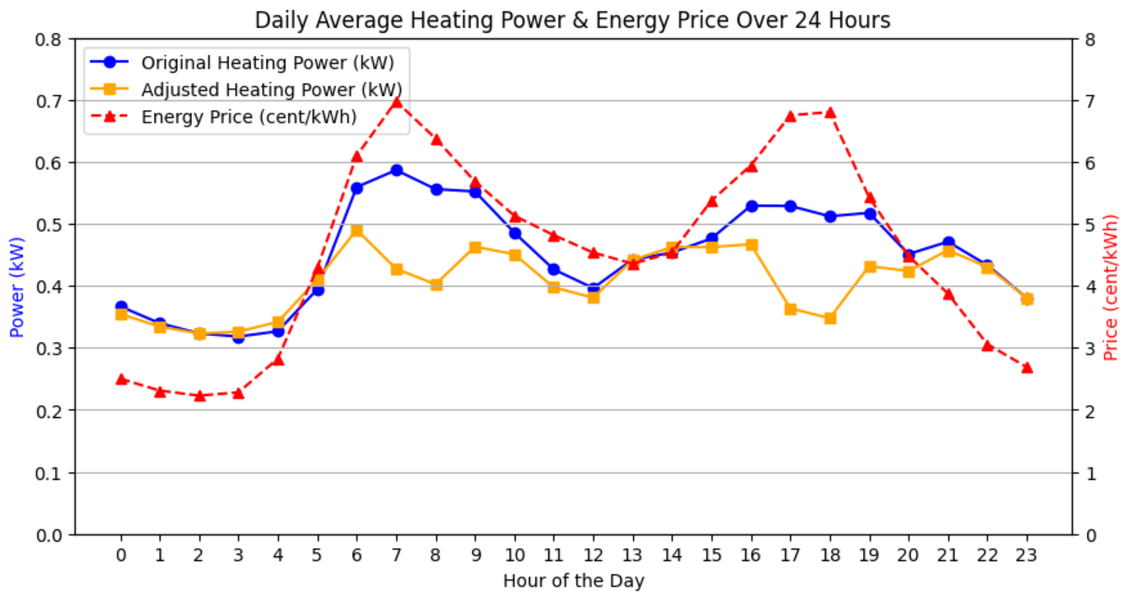

Figure 8. Hourly average energy consumption before and after heating-based DR in farm

Figure 8 shows the hourly average energy consumption in farm before and after implementing a heating-based demand response (DR) strategy. The blue line represents the original heating power consumption, while the orange line shows the adjusted heating power after applying the DR strategy. The red dashed line indicates the hourly energy price in cent/kWh. It is evident that the energy price peaks around 7–8 AM and again during the evening hours between 5–7 PM. In response, the DR strategy reduces heating power consumption during these high-price periods to minimize energy costs. Conversely, the heating load is slightly increased or maintained during hours with lower energy prices. This shift in heating demand helps to flatten peak load and align energy usage with more affordable pricing periods, ultimately promoting cost efficiency while maintaining indoor comfort.

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Commercial and public institutions also demonstrated valuable DR potential. For example, schools, with structured hours and substantial heating demands during winter, could save up to €51.56 annually (12.57% cost reduction) by adjusting heating schedules and implementing pre-heating. This corresponds to over 422.60 kWh (1.67% energy reduction) of energy savings, a notable contribution when scaled across multiple facilities. Figure 9 compares the original and adjusted heating power consumption with energy prices over 24 hours in school buildings. The adjusted heating power (orange) is reduced during peak price hours (around 7–8 AM and 5–6 PM), indicating a demand response strategy. This shift helps lower energy costs while maintaining overall heating levels.

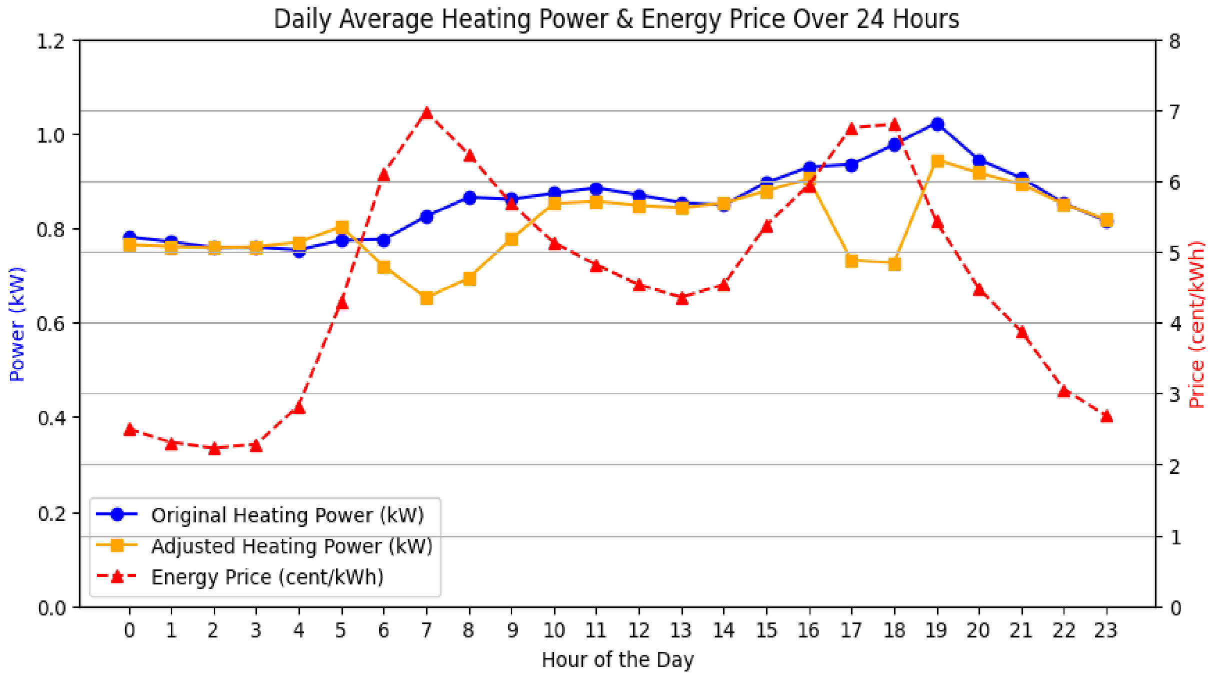

Figure 9. Hourly average energy consumption before and after heating-based DR in school buildings

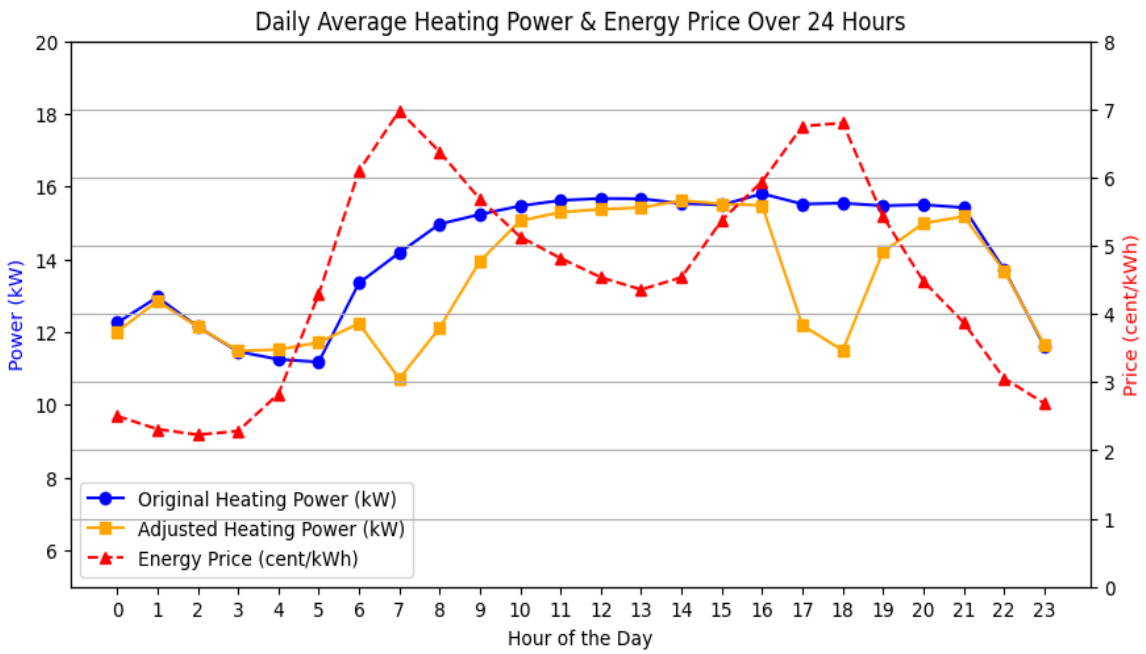

Figure 10. Hourly average energy consumption before and after heating-based DR in retail store

The most significant result was found in the retail sector, where heating loads were optimized to achieve €695.29 in cost savings with 13.33% cost reduction and a massive 7006.47 kWh of energy shifted from peak periods. These findings highlight the value of prioritizing energy efficiency and flexibility measures in commercial buildings, particularly through automated building energy management systems (BEMS). The figure 10 shows the hourly average heating power in a retail store before and after applying a heating-based demand response (DR) strategy. The original heating power remains steady throughout the day, while the adjusted power (orange) is reduced during peak price periods, especially around 6–8 AM and 5–6 PM. These reductions align with spikes in energy price (red dashed line), demonstrating cost-optimization behavior. The adjusted heating demand increases slightly during off-peak hours to compensate. This indicates a successful load-shifting strategy that preserves comfort while reducing energy costs. The figure 11 shows the monthly total heating power in a retail store before and after implementing a demand response (DR) strategy. The original heating power (blue) is consistently higher than the adjusted power (orange) throughout the year. The DR strategy achieves noticeable reductions, particularly in colder months like January, February, and December. The smallest difference occurs in summer months when heating demand is generally lower. Overall, the DR approach effectively reduces monthly heating energy consumption while aligning with seasonal variations.

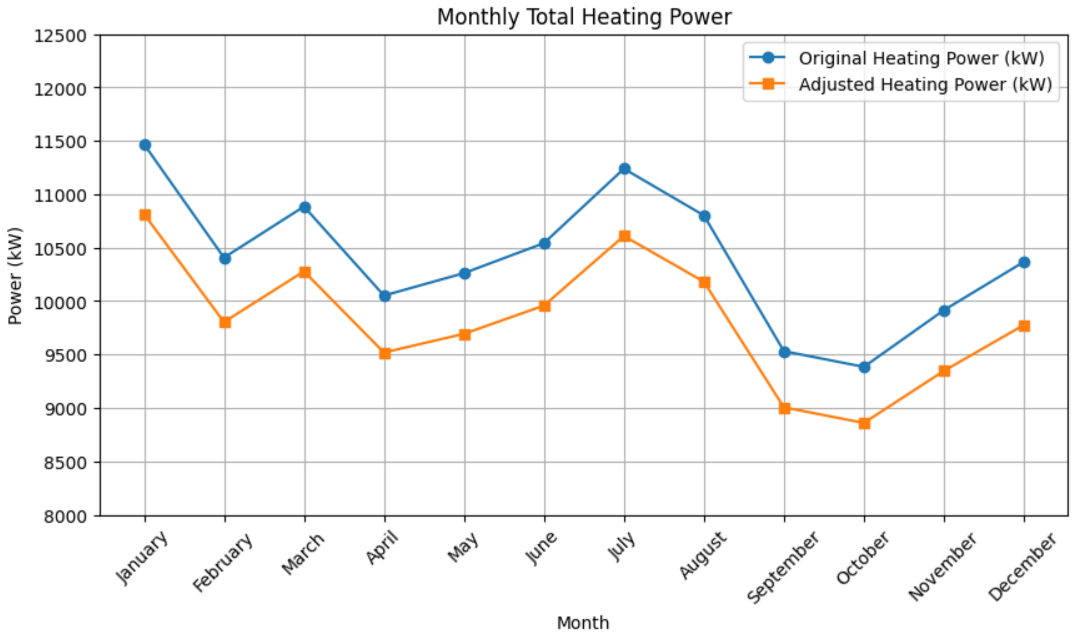

Figure 11. Monthly average energy consumption before and after heating-based DR in retail store

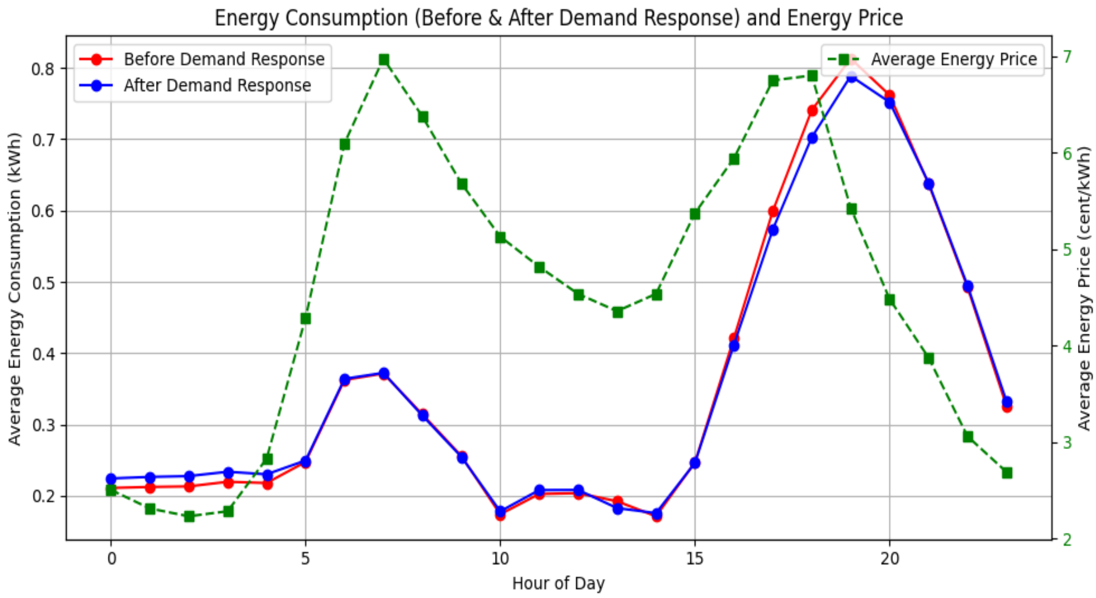

Figure 12. Hourly average energy consumption before and after appliance-based DR in hotel

Smaller segments such as cottages, hotels, and small offices also showed measurable benefits. Cottages achieved savings of €15.47 in appliance usage; hotels saved €2.96 on appliances and €13.87 on heating, for a total of 173.41 kWh shifted. Small offices, while consuming less energy overall, still contributed to the flexibility landscape with €1.19 saved and 9.32 kWh of energy shifted. While these numbers may appear modest individually, they become significant when aggregated over hundreds or thousands of consumers participating in a local flexibility program. The figure 12 shows hourly average energy consumption in a hotel before and after implementing appliance-based Demand Response (DR), along with average energy price. After DR, energy usage is reduced during peak price hours (17:00–21:00) and slightly shifted to lower-price periods. This indicates effective load shifting to optimize energy costs. Figure 13 illustrates hourly average heating power in a hotel before and after applying heating-based Demand Response (DR), along with energy price trends. Original heating power peaks during high-price hours (18:00–21:00), while the adjusted heating power shows a noticeable reduction during those peak-price periods. Heating loads are shifted to lower-price hours, especially around early morning and midday. The adjustment aligns energy consumption more closely with cheaper price periods. This shows effective load management and cost-saving through DR strategies.

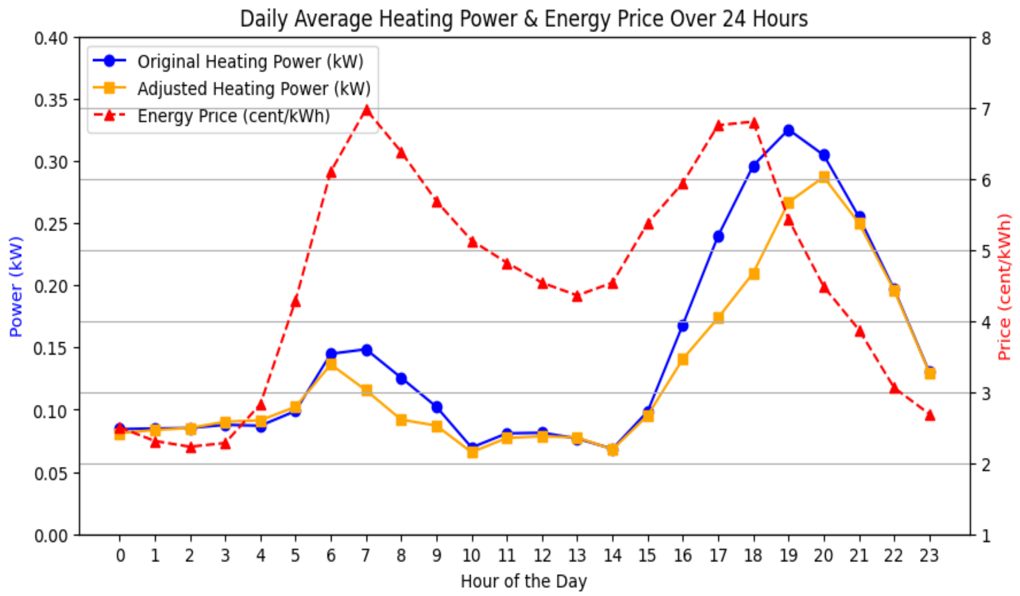

Figure 13. Hourly average energy consumption before and after heating-based DR in hotel

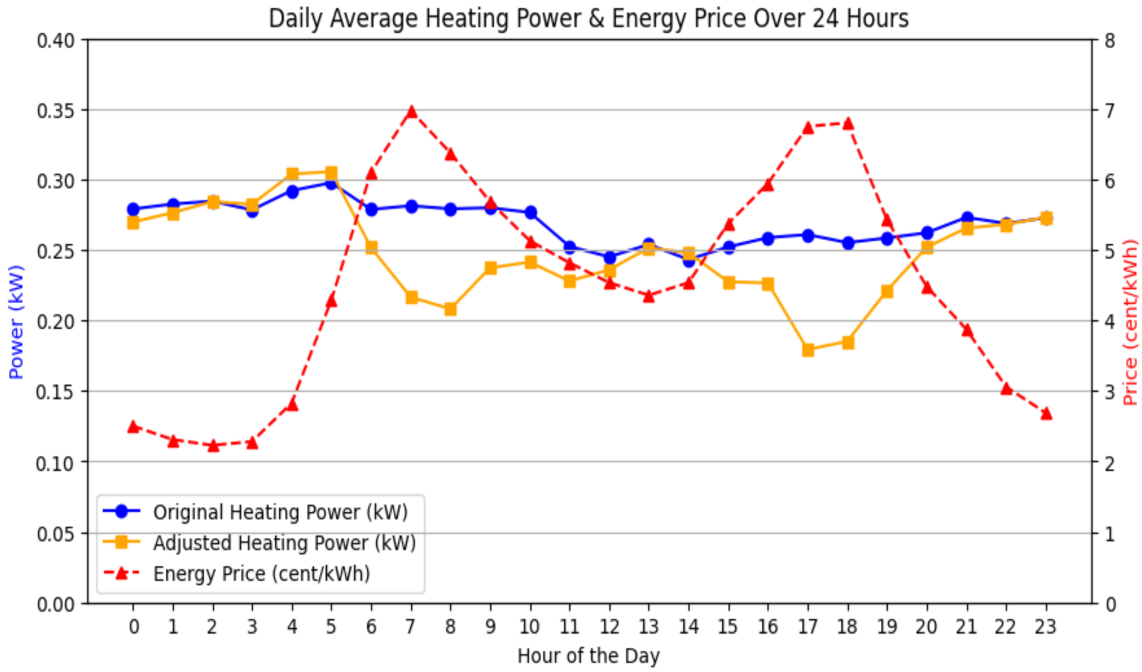

Figure 14. Hourly average energy consumption before and after heating-based DR in industry

Finally, industrial consumers participating in the analysis demonstrated €34.75 in annual heating savings (15.05% cost reduction) with approximately 193.33 kWh of peak-period energy avoidance. Given the continuous operation and process-driven nature of industry, the DR potential in this sector may require deeper technical integration and real-time control to be fully exploited. However, even small-scale interventions such as thermal energy storage or demand forecasting can yield considerable operational benefits. Figure 14 shows industrial heating power consumption before and after heating-based Demand Response (DR), alongside energy price trends. The adjusted heating power is significantly reduced during high-price hours (6:00–8:00 and 17:00–19:00). This load is shifted to lower-price periods, especially in early morning and evening. The DR strategy effectively reduces energy costs by aligning consumption with off-peak pricing.

3.3 Optimized Heating Power Demand

The figure presents a piecewise linear regression analysis between outdoor temperature and optimized heating power demand for a residential building, which is a critical component in demand response (DR) strategies. The data is seasonally segmented, with wintertime and summertime observations plotted in orange and blue, respectively (Figure 15). The objective of this analysis is to characterize how heating power demand responds to varying outdoor temperatures, enabling the development of intelligent DR mechanisms that can adapt to seasonal behavior.

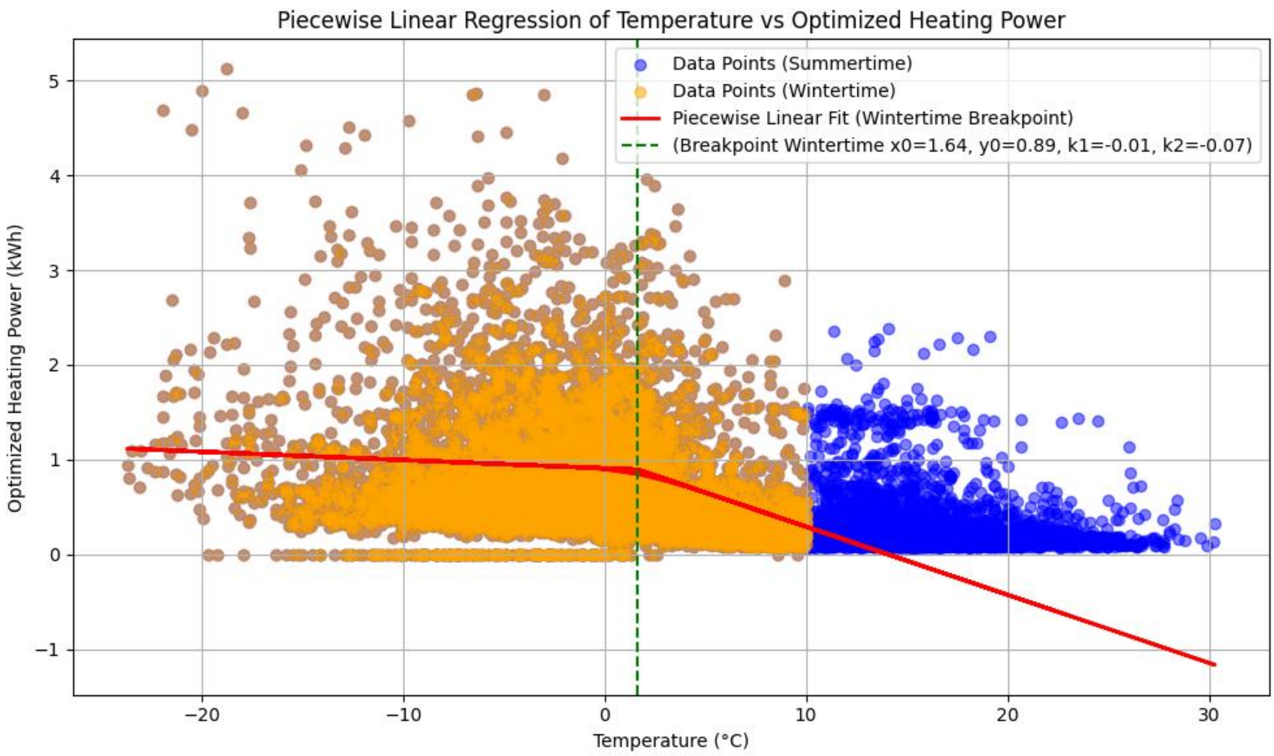

Figure 15. Optimized heating power demand for a residential building

In winter, the relationship between temperature and heating demand becomes more complex due to the thermal characteristics of buildings and occupant behavior (Delzendeh et al., 2017). A piecewise linear model has been fitted to the winter data to capture the non-linear pattern of heating power requirements. The model identifies a breakpoint at approximately 1.64 °C, with a corresponding heating demand of 0.89 kWh. The slopes before and after the breakpoint are -0.01 and -0.07, respectively. This indicates a relatively stable heating demand above the breakpoint and a steeper decrease in heating power with rising temperatures beyond that point. This breakpoint represents the transition threshold where heating systems begin to reduce operation more significantly as outdoor temperatures increase, thus offering a valuable control point for DR actions.

Understanding this relationship is vital for optimizing residential heating schedules and aligning them with grid-level objectives. For example, during peak demand periods or when renewable generation is high, heating systems can be adjusted dynamically without compromising indoor comfort, leveraging the thermal inertia of buildings. This enables load shifting and peak shaving in residential areas, contributing to grid stability and energy efficiency. Moreover, this kind of model-driven insight supports the deployment of automated DR systems that can predict and precondition residential loads based on weather forecasts. In essence, this regression model serves as a foundational step towards integrating smarter, seasonally-aware DR solutions in residential energy systems.

3.4 Implications and Aggregated Impact

The collective outcomes from the demand response analysis demonstrate that peak shaving and load shifting can be effectively implemented in diverse customer categories using existing infrastructure and simple control logic. Table-based summaries and visualizations developed in this task show that the retail, farming, and residential consumers represent the largest opportunity for grid support and cost optimization through DR. Residential consumers, especially those using heat pumps or electric heating, also contribute significantly, particularly during the winter months when peak loads are high and grid stability is critical.

While the absolute savings per user may be modest in many categories, the cumulative effect across a region-wide program involving hundreds of end-users can be substantial (Reeve et al., 2022). For example, shifting just 1 MWh of peak-period consumption to off-peak periods per day across a community can significantly reduce strain on substations and transformer capacity, while deferring costly network upgrades. The findings strongly support investment in DR-enabling technologies, including smart thermostats, programmable logic controllers (PLCs), and dynamic pricing models. Additionally, raising awareness among end-users about the financial and environmental benefits of participating in DR programs could further accelerate adoption. To fully realize the DR potential identified in this task, stakeholders such as DSOs, municipal energy agencies, and technology providers must collaborate to deploy scalable DR programs supported by data platforms, flexibility markets, and customer engagement strategies.

3.5 Conclusion

The analysis of the 02_Porkholm and 03_Centrum networks offers valuable insights into identifying target segments for implementing demand response (DR) strategies. By using one year of hourly energy consumption data and applying clustering techniques based on user profiles, the study revealed diverse consumption behaviors across user types, particularly residential and commercial sectors.

The findings indicate that residential buildings and retail stores are the most promising target groups for DR implementation. Residential consumers form the majority in both networks and exhibit considerable flexibility in their load patterns, especially during evening hours when peak demand typically occurs. This flexibility makes them suitable candidates for load shifting through DR strategies such as time-of-use pricing and smart appliance control. Additionally, residential users often use electric heating and other shiftable appliances, further enhancing their potential for participation in DR programs.

Retail stores, with only one identified in the analyzed networks, determine relatively high energy consumption with predictable operational hours, usually during the daytime. This makes them ideal candidates for targeted DR programs focused on peak shaving or scheduled load reductions. Implementing DR in such settings is more manageable due to one retail store in the network, which simplifies the coordination and monitoring of demand-side interventions. The 02_Porkholm network, being larger and more diverse, presents opportunities for more granular and segment-specific DR strategies. In contrast, the 03_Centrum network, with its smaller and more homogeneous load profiles, is well suited for broader, community-level behavioral DR initiatives.

In summary, the combination of high user volume and operational flexibility makes residential buildings a primary target for DR deployment, while the single retail store stands out as a high-impact, easy-to-manage DR candidate. Using DR strategies to these segments can significantly enhance network efficiency, reduce peak loads and support the overall goals of flexibility and sustainability in the energy system.

4 Impact of Renewable Energy and Electric Vehicles Adoption

The integration of renewable energy sources and the ongoing electrification of heating and transport systems are introducing new complexities to traditional distribution networks (Gallegos et al., 2024). These developments, while essential for a sustainable and decentralized energy future, pose operational challenges related to grid congestion, voltage deviations and thermal overloads; especially at the distribution level (Al-Amin et al., 2025; Fasbir et al., 2020). This section addresses the implications of increased electricity generation and consumption on the Porkholm and Centrum networks, with a focus on grid hosting capacity (HC), flexibility needs, and the role of demand response and battery storage.

4.1 Hosting Capacity of the Networks

Hosting capacity refers to the maximum amount of distributed energy resources (DERs), such as solar or wind power, that can be connected to the network without violating technical constraints (Islam et al., 2025). These constraints include voltage limits, thermal capacity of lines and transformers, and power quality thresholds. In this study, hosting capacity was calculated using simulations based on current network data and expected future usage patterns.

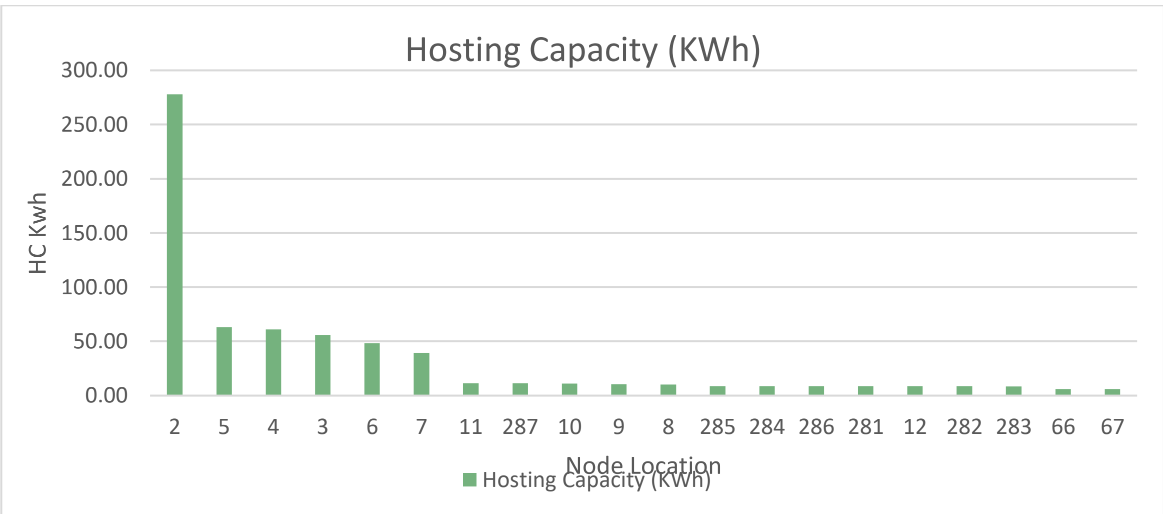

Figure 16. Top 20 hosting capacity and node location of 02_ Porkholm network

For the 02_Porkholm network, the total hosting capacity was estimated at 1675.46 kWh, while for the 03_Centrum network, the capacity stood at 1190.89 kWh. Figure 16 represents the top 20 hosting capacity and node location of 02_ Porkholm network, and Figure 17 shows the top 20 hosting capacity and node location of 02_ Centrum network. These values suggest that while there is still room for DER integration, it is limited. Particularly in winter months or under scenarios involving significant rooftop PV or small wind installations, there is a tangible risk of exceeding these limits, leading to technical violations and potential equipment damage.

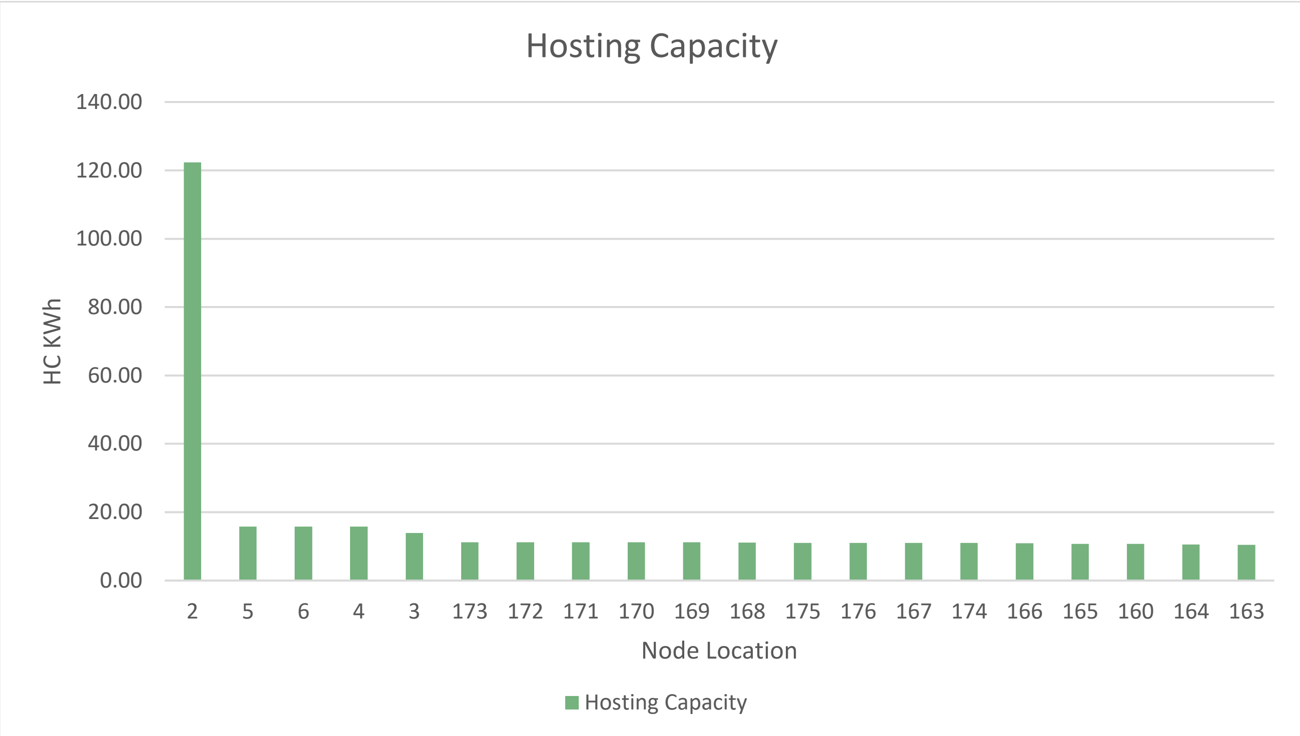

Figure 17. Top 20 hosting capacity and node location of 02_ Centrum network

Furthermore, the physical layout of these two networks affects their flexibility potential. Porkholm, with its long, radial feeders and dispersed load points, is more susceptible to voltage issues at the extremities. In contrast, Centrum, being more compact and urban in character, faces congestion risks but benefits from shorter feeder lengths and a more centralized load pattern.

4.2 Impacts of Electrification and Renewable Integration

Electrification especially of heating systems (heat pumps, electric boilers) and transportation (EVs) adds substantial new demand to the grid. If this new demand coincides with existing peaks, or if DER output is fed back into the grid during low-demand periods, network components may exceed their operational limits (Drude et al., 2014). The proliferation of EVs, in particular, introduces a new kind of peak load: short-duration, high-intensity charging events that may occur simultaneously across residential neighborhoods.

Coupled with the intermittent and location-specific nature of renewable generation (e.g., rooftop solar), these changes call for new operating strategies. Without intervention, such as reinforcement of transformers, cables, or voltage regulation systems, these networks could face service reliability issues. However, reinforcing physical infrastructure is costly, disruptive, and slow. This brings attention to non-wire alternatives, primarily demand-side flexibility and local energy storage, as practical and immediate solutions.

4.3 Flexibility Needs and Demand Trends

To better understand future flexibility needs, projected annual load and generation growth rates were incorporated into the analysis. According to Fingrid's national-level forecast, load growth is expected to be 5.9% per year, while distributed generation is projected to increase by 7.04% per year (Fingrid, 2024). These trends imply that not only will networks experience increased overall throughput, but the timing and direction of power flows will become more variable and harder to predict.

For both networks, this variability reinforces the need for real-time demand control and location-based load balancing. As shown in earlier sections, consumers equipped with smart heating systems or controllable appliances already offer some degree of flexibility. Scaling these capabilities through automation, tariff incentives, and user engagement will be critical for meeting future system demands without widespread infrastructure upgrades.

4.4 Conclusions

The capacity assessment of the Porkholm and Centrum networks reveals that grid hosting limits are already being approached under current consumption and generation trends. The anticipated growth in renewable energy integration and electrification will increase pressure on network components, especially during winter peaks and summer generation surges. Instead of relying solely on costly infrastructure expansion, this study highlights the strategic value of demand flexibility, battery storage, and smart control systems in meeting future grid challenges.

These flexibility resources can not only enhance grid reliability and resilience but also defer or eliminate the need for traditional reinforcements, saving both time and investment. To unlock this potential, coordinated planning across municipalities, DSOs, and technology providers will be essential. The findings of this section will directly support subsequent tasks in WP1 focused on long-term energy planning, reliability analysis, and policy recommendations for scalable and sustainable flexibility deployment.

5 Identification of Flexible Resources and Development Opportunities

As the need for grid flexibility becomes more urgent due to increased demand and distributed generation, the role of flexible resources particularly battery energy storage systems (BESS) is gaining prominence (Kleanthis et al., 2024). In distribution networks like Porkholm and Centrum, where traditional grid reinforcements are expensive and slow to deploy, battery storage can serve as a key enabler of operational flexibility. Batteries provide several services: they can mitigate peak demand, store excess renewable energy, support voltage stability, and enable time-shifting of loads through demand-side management (Maghami et al., 2024). This section explores the detailed sizing, operation, and economic implications of deploying battery storage in the two networks under study, considering both technical constraints and market-based opportunities for flexibility services.

5.1 Battery Storage as a Flexibility Solution

Battery storage can be deployed at various locations in the distribution network to address multiple challenges. At the grid edge, batteries can provide voltage support and reduce power flows on overloaded lines (Chidambaram & Paramasivam, 2013). Closer to substations, they can serve as a bulk energy reservoir that smoothens the net load profile and mitigates transformer stress. Moreover, BESS units integrated with smart meters and DR-ready devices can participate in advanced control schemes where both load and generation are dynamically optimized in response to real-time signals (Chakraborty et al., 2022).

In the context of the PEAK project, the emphasis is on using batteries not as backup power sources, but as active grid participants capable of enhancing reliability, reducing energy costs, and improving the efficiency of renewable integration. These batteries are envisioned to operate under hybrid control modes, including peak shaving, load shifting and frequency regulation. While ancillary services markets are not yet fully developed at the distribution level in Finland, the anticipated regulatory changes and market design reforms could soon allow distribution-connected assets to participate in multiple value streams.

5.2 Load Profiles and Battery Sizing Methodology

To size the battery systems for optimal operation, the first step involved modeling the hourly load profiles of both networks across typical peak days. Two primary scenarios were considered: a maximum load day (e.g., a cold winter weekday with high heating demand) and an average load day (e.g., moderate load conditions typical in spring or autumn).

For each scenario, the analysis includes the calculation of the following:

- Total energy required to be supplied during peak hours (kWh)
- Duration of peak periods (9 hours)
- Battery energy capacity (kWh) needed to fully cover peak load
- Battery power rating (kW) required for delivery over the peak window

The simulations accounted for typical round-trip battery efficiency (approximately 90%) and assumed full charging during off-peak hours using surplus renewable or low-cost grid energy. Batteries were assumed to be stationary lithium-ion systems with performance characteristics aligned with commercially available solutions in 2025 (Bubulinca et al., 2023).

5.3 Battery Sizing Results: 02_Porkholm Network

In the 02_Porkholm network, the maximum observed peak demand was 6181.10 kWh. To reduce this peak load effectively, the required battery supply over a 9-hour period was estimated at 1854.33 kWh, leading to a necessary power capacity of 2225.20 kW. Under the average load scenario, where peak demand was about 2104.09 kWh, the required battery energy during the same time window was 631.23 kWh, corresponding to a power capacity of 757.47 kW.

Thus, the optimum operating range for battery systems in Porkholm falls between 757.47 kW and 2225.20 kW. Deploying storage within this range would allow the network to meet flexibility needs during both typical and extreme load conditions without risking overloads or voltage instability.

Additionally, these batteries can be configured to charge during midday hours, when solar PV generation is at its peak and demand is relatively low.

5.4 Battery Sizing Results: 03_Centrum Network

In the 03_Centrum network, the maximum load reached 5045.37 kWh, requiring a battery discharge of 1513.61 kWh over the 9-hour peak period. The corresponding power capacity was 1816.33 kW. Under the average load profile, battery energy and power requirements dropped to 552.53 kWh and 663.03 kW, respectively.

This suggests that the Centrum network, although smaller in physical scale, still demands significant flexibility support due to its dense load clusters and lack of redundancy in feeder topology. As in Porkholm, the recommended battery capacity range (663.03 kW to 1816.33 kW) provides a scalable envelope within which storage deployment can be tailored based on evolving network needs and financial viability.

5.5 Economic Evaluation of Battery Operation

To assess the financial implications of battery deployment, a basic cost-benefit analysis was performed using a cut-off price for demand flexibility set at €0.06/kWh. This price reflects the estimated value of shifting consumption or injecting energy during critical hours based on current electricity tariffs and avoiding network losses. For the average load scenario, the total charging cost is €32.77, and the total discharging revenue is €56.72 (Table 3). This results in total cost savings of €23.95, indicating a moderate financial benefit from battery operation. In the maximum load scenario, the charging cost increases to €104.28 due to higher energy demand. However, the discharging revenue also rises significantly to €166.84, leading to cost savings of €62.55. The greater savings under maximum load highlight the potential for higher returns when the battery is used more intensively. Both cases show that battery operation is economically advantageous, with net gains in each scenario.
The data suggests that optimizing charging and discharging schedules can yield meaningful cost reductions. Figure 18 shows the cost of battery charging and revenue from discharging across 24 hours

for the average load in Porkholm. Charging mostly occurs during off-peak hours (blue zones) when energy prices (orange dashed line) are below the threshold (purple line). Discharging is concentrated during peak hours (red zones) when prices exceed the threshold, maximizing revenue. Charging costs (blue line) and discharging revenues (green line) fluctuate with energy prices. This strategy supports economic operation by exploiting price differences across the day. Figure 19 illustrates the charging cost and discharging revenue for the maximum load in Porkholm, with charging done during low-price off-peak hours and discharging during high-price peak hours. The cost and revenue trends follow the energy price curve, optimizing profit based on the price threshold.

Table 3. Cost Analysis of 02_ Porkholm

Topic	For Average Load	For Maximum Load
Total Charging Cost	€32.77	€104.28
Total Revenue from Discharging	€56.72	€166.84
Total Cost Savings	€23.95	€62.55

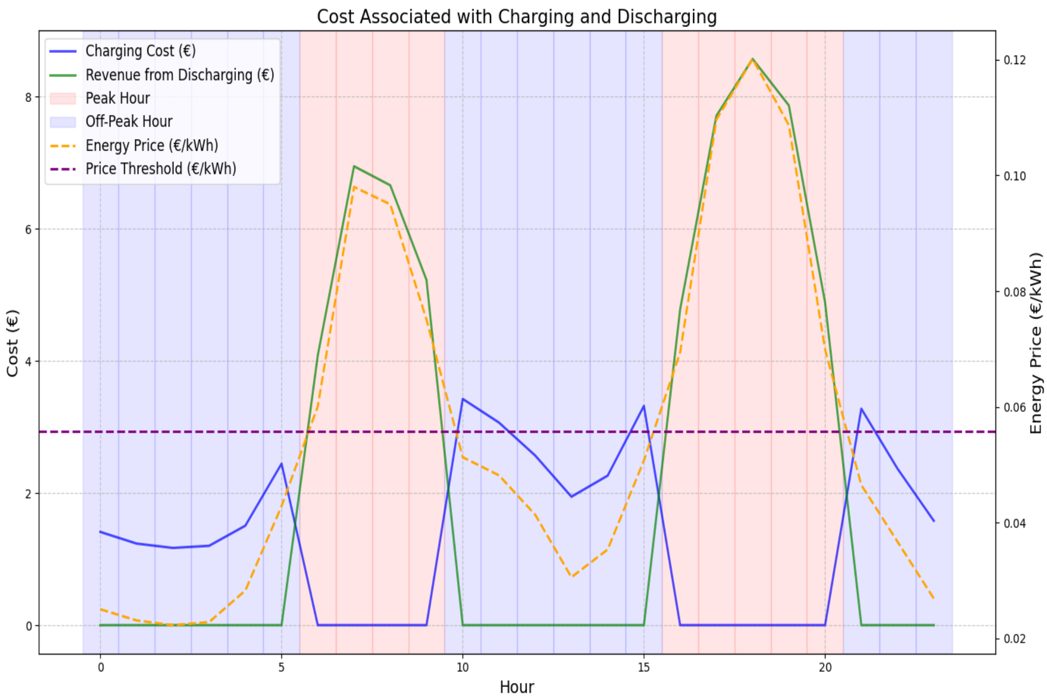

Figure 18. Cost associated with charging and discharging for average load in 02_ Porkholm

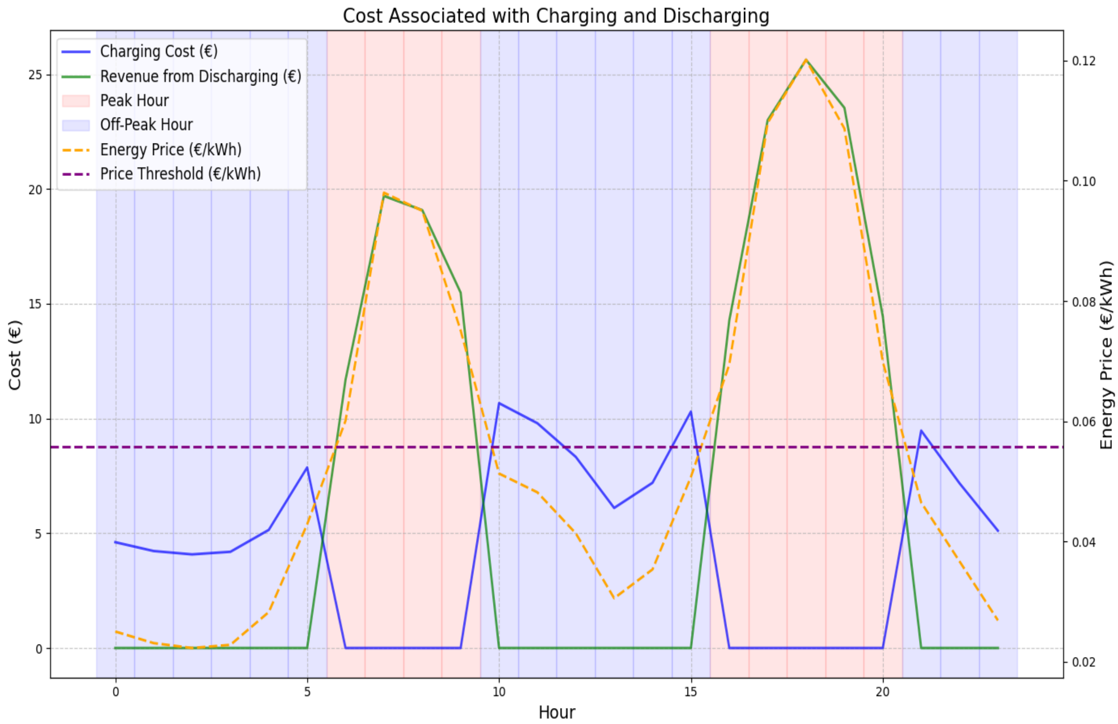

Figure 19. Cost associated with charging and discharging for maximum load in 02_ Porkholm

Table 4. Cost Analysis of 03_Centrum

Topic	For Average Load	For Maximum Load
Total Charging Cost	€29.95	€83.76
Total Revenue from Discharging	€49.86	€136.52
Total Cost Savings	€19.91	€52.76

Under average load conditions, savings were more modest (€23.95 in Porkholm and €19.91 in Centrum), but still economically justifiable, particularly when scaled over multiple peak events annually. These savings reflect only direct operational margins; the real economic value would be higher when considering deferred grid reinforcements, reduced outage risk and improved DER hosting capacity. The table 4 summarizes the economic evaluation of battery operation at 03_Centrum under average and maximum load conditions. Under average load, the battery incurs a charging cost of €29.95 but earns €49.86 from discharging, yielding €19.91 in cost savings. For maximum load, higher costs

(€83.76) and revenues (€136.52) result in greater savings of €52.76. This demonstrates that battery operation is financially beneficial, especially under higher load scenarios.

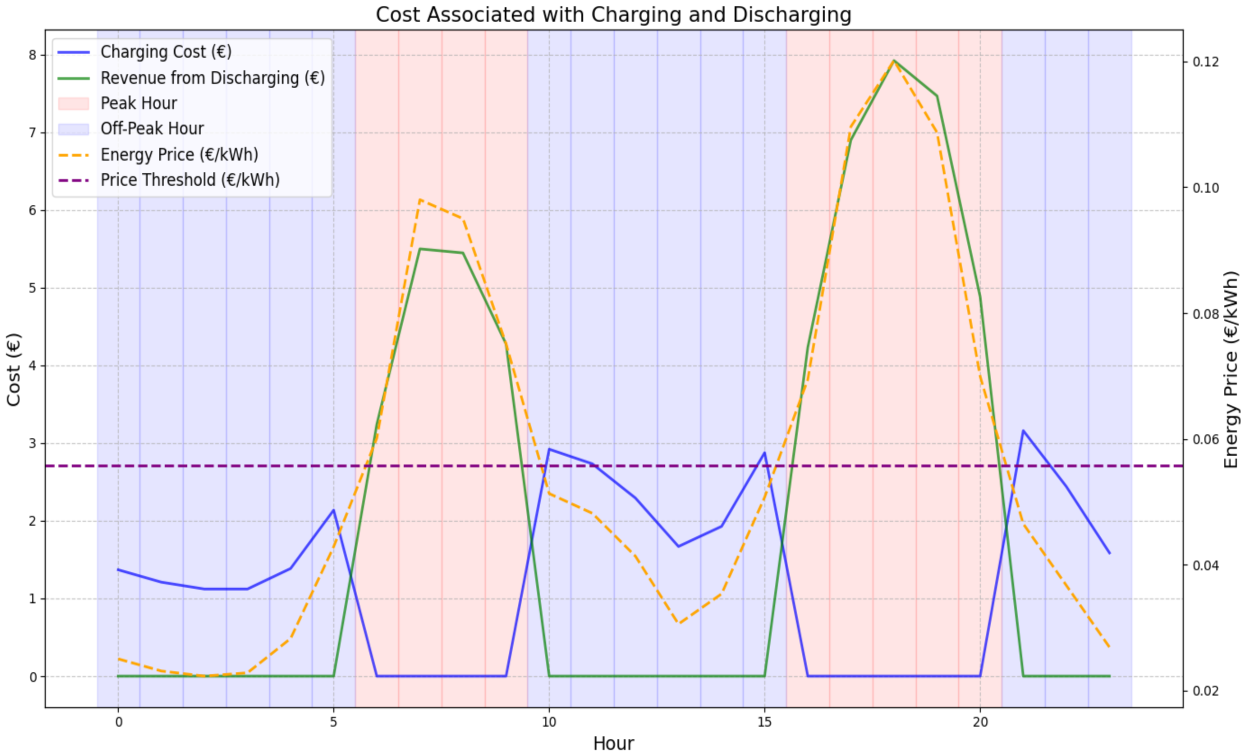

Figure 20. Cost associated with charging and discharging for average load in 03_Centrum

Furthermore, once regulatory pathways are in place, these batteries could be monetized in multiple value streams including participation in balancing services, congestion management programs, and energy arbitrage in local flexibility markets substantially improving their payback periods. Figure 20 presents the charging cost and discharging revenue for the average load in Centrum over 24 hours. Charging is primarily done during off-peak periods (blue zones) when energy prices are below the threshold, minimizing cost. Discharging occurs during peak hours (red zones) when prices are higher than the threshold, maximizing revenue. The strategy effectively leverages hourly price variations for economic operation. Figure 21 illustrates the cost associated with charging and the revenue from discharging for the maximum load in the Centrum area over a 24-hour period. Charging primarily takes place during off-peak hours (shaded blue), specifically between hours 0–6, 10–15, and 21–23, when the energy price falls below the set threshold of 0.06 €/kWh (indicated by the purple dashed line). The charging cost (blue line) reaches its highest points around hours 10 and 15, exceeding 10 €, due to higher energy demand during these periods. Discharging occurs strategically during peak hours (shaded red), particularly between hours 7–9 and 17–20, when energy prices rise above the threshold. The discharging revenue (green line) peaks at over 22 € during hour 18, which corresponds with the day's maximum energy price of approximately 0.12 €/kWh. The orange dashed line representing energy price closely follows the discharging pattern, indicating that the control strategy is effectively price-driven. Overall, this approach ensures that energy is stored when prices are low and sold when prices are high, maximizing economic benefit from storage operations.

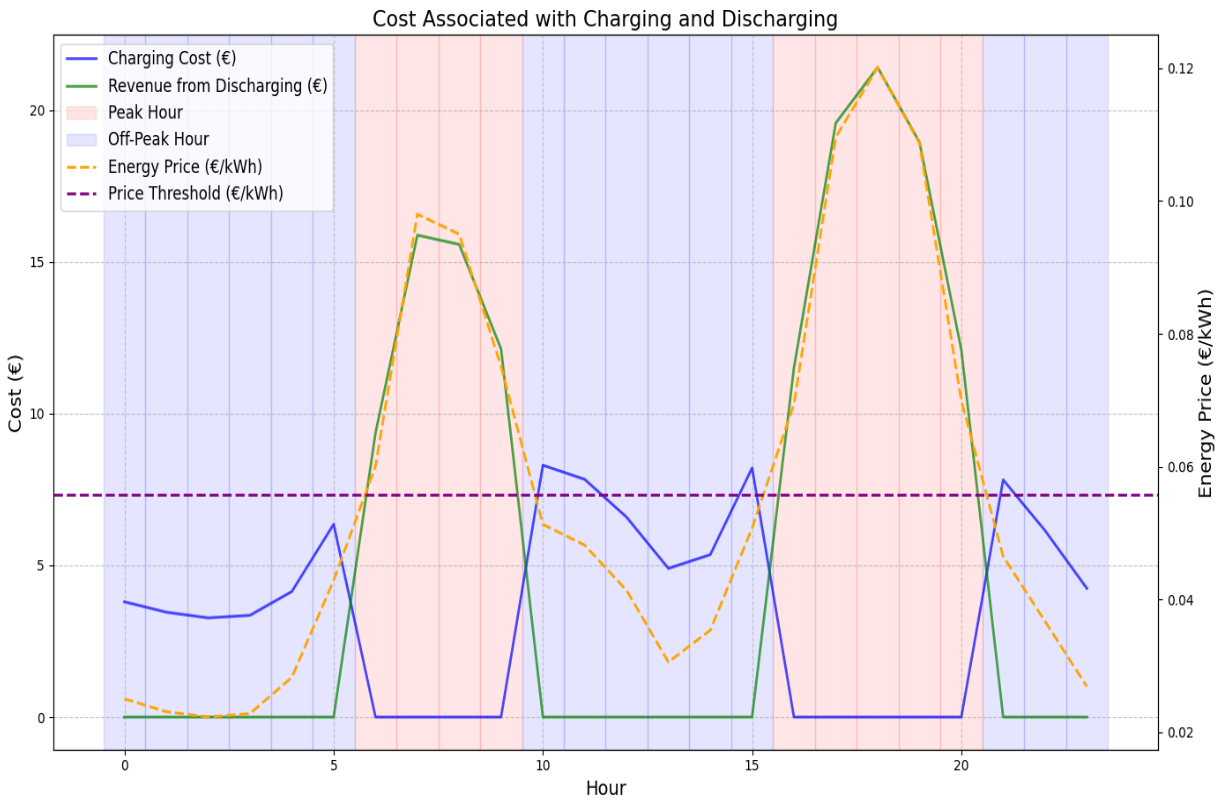

Figure 21. Cost associated with charging and discharging for maximum load in 03_Centrum

5.6 Strategic Deployment and Locational Optimization

The effectiveness of battery energy storage systems (BESS) in supporting distribution network operations is highly dependent on their placement within the network topology. Locational optimization is essential to maximize technical benefits such as peak load reduction, voltage support, and loss minimization (Nottrott et al., 2013). In Task T1.2, a node-level allocation analysis was conducted to identify the top candidate locations for BESS deployment under both average and maximum load conditions for the 02_Porkholm and 03_Centrum networks. These results, based on allocated peak demand and associated battery power capacities at each node, reveal clear patterns that inform strategic deployment strategies.

Top Nodes for Battery Allocation:

	Node	Allocated Peak Demand (kWh)	Allocated Battery Power Capacity (kW)
0	50.0	68.941601	82.729921
1	76.0	51.340788	61.608945
2	79.0	51.340788	61.608945
3	252.0	45.575801	54.690961
4	203.0	40.681948	48.818337
5	32.0	35.598054	42.717665
6	257.0	30.203491	36.244189
7	129.0	29.932119	35.918543
8	58.0	20.192393	24.230871
9	231.0	20.078329	24.093994
10	277.0	17.931010	21.517212
11	269.0	17.289553	20.747464
12	184.0	16.869504	20.243405
13	280.0	16.560413	19.872496
14	23.0	16.069972	19.283967
15	37.0	16.069972	19.283967
16	45.0	15.043168	18.051802

Figure 22. Battery capacity associated with node location for average load in 02_ Porkholm

In the 02_Porkholm network, which spans 55.39 km and includes 287 nodes, battery allocation is naturally more dispersed. The top-performing nodes under average load conditions include Node 50, Node 76 and Node 79, each with peak demands exceeding 50 kWh and requiring battery capacities in the range of 61–83 kW (Figure 22). These nodes are likely to be situated toward the middle or end of feeder branches, where voltage drops are more pronounced, and peak demand is not easily absorbed by upstream assets. Under maximum load conditions, nodes such as 203, 50 and 76 exhibit the highest allocated peak demand up to 137.4 kWh, requiring battery capacities of 164.84

kW (Figure 23). These values suggest that these locations are critical in managing winter peak loads and should be prioritized for first-phase storage deployments.

Interestingly, nodes that appear in both the average and maximum load top rankings (e.g., Node 50, 76, 129 and 203) represent strategically vital points where battery systems can provide flexibility under a variety of load conditions. These nodes likely correspond to residential clusters or small commercial users located further from substations, where storage can mitigate both thermal and voltage constraints.

Top Nodes for Battery Allocation:

	Node	Allocated Peak Demand (kWh)	Allocated Battery Power Capacity (kW)
0	203.0	137.3733	164.84796
1	50.0	113.0922	135.71064
2	76.0	113.0922	135.71064
3	129.0	100.1646	120.19752
4	58.0	94.8024	113.76288
5	252.0	93.7116	112.45392
6	32.0	93.2094	111.85128
7	257.0	89.9235	107.90820
8	280.0	75.1842	90.22104
9	37.0	70.4106	84.49272
10	184.0	69.3144	83.17728
11	277.0	65.3940	78.47280
12	231.0	63.5175	76.22100
13	54.0	57.0780	68.49360
14	269.0	49.5180	59.42160
15	45.0	48.8511	58.62132
16	283.0	47.9682	57.56184

Figure 23. Battery capacity associated with node location for maximum load in 02_ Porkholm

In contrast, the 03_Centrum network which is more compact and includes only 176 nodes shows a more centralized battery allocation. Under average load conditions, Node 143, 27 and 157 are the top candidates, with peak demands ranging from 104 to 132 kWh and required battery capacities of up to 159 kW (Figure 24). Under maximum load scenarios, Node 27 and 157 dominate the allocation with peak demands exceeding 310 kWh and battery capacities above 370 kW (Figure 25). These values point to heavily loaded segments of the network potentially serving commercial buildings,

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schools or public facilities with significant daytime consumption. The presence of nodes such as 22, 92 and 131 in both load conditions suggests that these areas consistently experience stress and should also be considered for storage investment.

Top Nodes for Battery Allocation:

	Node	Allocated Peak Demand (kWh)	Allocated Battery Power Capacity (kW)
0	143.0	132.781965	159.338358
1	27.0	106.625029	127.950034
2	157.0	104.468887	125.362664
3	22.0	40.484951	48.581941
4	92.0	36.138209	43.365851
5	131.0	32.476957	38.972349
6	106.0	31.135515	37.362618
7	41.0	27.209493	32.651392
8	38.0	18.642740	22.371288
9	10.0	13.617162	16.340595
10	16.0	8.878559	10.654271
11	173.0	0.066961	0.080354

Figure 24. Battery capacity associated with node location for average load in 03_Centrum

Top Nodes for Battery Allocation:

	Node	Allocated Peak Demand (kWh)	Allocated Battery Power Capacity (kW)
0	27.0	310.7727	372.92724
1	157.0	310.7673	372.92076
2	143.0	172.0548	206.46576
3	22.0	163.0341	195.64092
4	92.0	113.1516	135.78192
5	106.0	110.3112	132.37344
6	131.0	105.6024	126.72288
7	41.0	78.4944	94.19328
8	38.0	68.0076	81.60912
9	10.0	52.0587	62.47044
10	16.0	28.8063	34.56756
11	173.0	0.5508	0.66096

Figure 25. Battery capacity associated with node location for maximum load in 03_Centrum

The Centrum network's limited geographic spread and higher node density allow for fewer but more powerful BESS installations, focusing on areas of concentrated demand and minimal voltage headroom. This contrasts with Porkholm, where a more distributed deployment may be required to cover wider spatial variability and longer feeder lengths. In both networks, it is advisable to prioritize nodes that appear in the top rankings for both load conditions, as these locations are most likely to experience persistent stress across seasons and daily cycles.

From a practical planning perspective, these findings can guide DSO investment strategies by identifying high-impact locations where battery storage can offer immediate operational relief and long-term flexibility value. They also support the development of locational pricing models or incentive structures for flexibility, where customers or community groups near critical nodes could be encouraged to host BESS or participate in demand response schemes. Future analysis in WP1 will build on this work by applying geospatial analytics and power flow modeling to create a node-level flexibility heat map. This will guide DSOs and municipalities in determining where battery investments will be most impactful and cost-efficient.

5.7 Conclusion

Battery storage represents a transformative solution for enabling grid flexibility and supporting the transition to a more sustainable and decentralized energy system. The analysis conducted in this task confirms that both Porkholm and Centrum networks can benefit significantly from BESS deployment, with technically viable and economically attractive sizing options already available. Strategic deployment of these assets coupled with demand-side flexibility and smart grid technologies can mitigate peak loads, defer capital investments and support higher levels of renewable energy integration.

As the country continues in process of transforming its energy policy and market structure according to the current needs, the integration of flexible resources like BESS will become a central pillar of distribution system planning. This task lays the foundation for a scalable, data-driven approach to storage deployment and underscores the importance of aligning technical analysis with long-term planning goals. The insights provided here will add the final phases of WP1, especially in evaluating system reliability, long-term scenario planning, and policy recommendations for flexible grid development.

6 Potential for The Reliability of The Region's Energy System: Future Planning and Grid Development

The transition towards a carbon-neutral and decentralized energy system is not only about deploying renewable energy technologies and flexibility resources, but also about reimagining the way distribution networks are planned, operated and managed (Shafiei et al., 2024). As demonstrated in the preceding sections, both Porkholm and Centrum networks already face technical and economic constraints that challenge their ability to absorb growing energy demand and distributed energy resource (DER) integration. This section focuses on the forward-looking dimension of WP1 by analyzing projected growth trends in load and generation, identifying potential stress points in the grid and proposing strategies for long-term planning that align with national energy goals and local development needs.

6.1 Load and Generation Forecasts

Accurate forecasting of electricity demand and generation is fundamental to proactive grid planning. According to Fingrid's national energy outlook, Finland is expected to experience an annual load growth rate of 5.9% and a distributed generation growth rate of 7.04%, driven by electrification of heating and transport, energy efficiency improvements and the rapid adoption of rooftop solar and community energy systems (Fingrid, 2024).

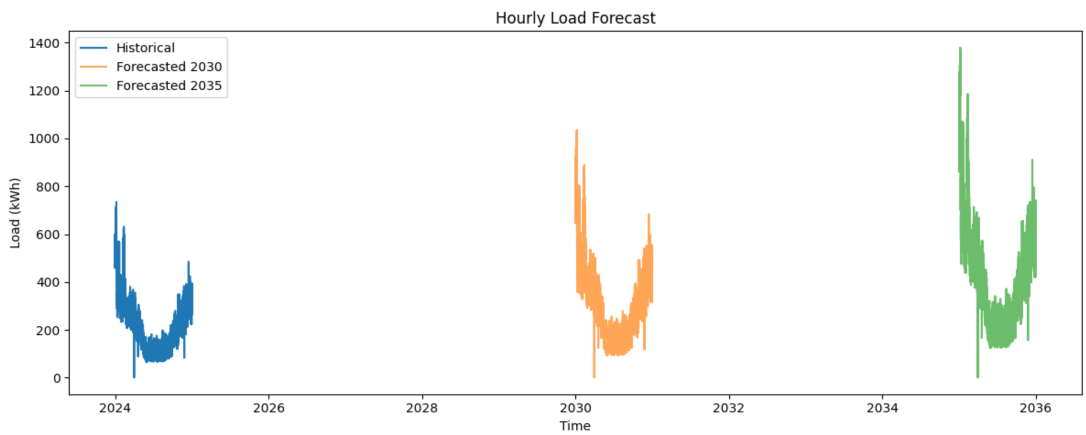

Figure 26. Hourly load forecast of 02_Porkholm network in 2030 and 2035

The figure 26 illustrates the historical and forecasted electricity demand for the 02_Porkholm network, covering three time periods: historical data around the year 2024, and forecasted data for the years 2030 and 2035. The vertical axis represents the load in kilowatt-hours (kWh), ranging from 0 to approximately 1400 kWh, while the horizontal axis spans the years from 2023 to 2036. The historical load, shown in blue, reflects a demand pattern in 2024 that fluctuates between about 100 kWh and 750 kWh, indicating moderate consumption with periodic peaks. The orange curve represents the forecast for 2030, where the load rises more sharply, reaching a peak close to 1050 kWh. This increase suggests a significant growth in electricity demand over the six-year period. The green line depicts the 2035 forecast, which shows even higher and more variable demand, peaking at around 1350 kWh. This represents roughly an 80% increase in peak load compared to 2024. The progression from 2024 to 2035 highlights a steady and substantial rise in electricity consumption, likely driven by factors such as population growth, increased electrification, and changing energy usage patterns.

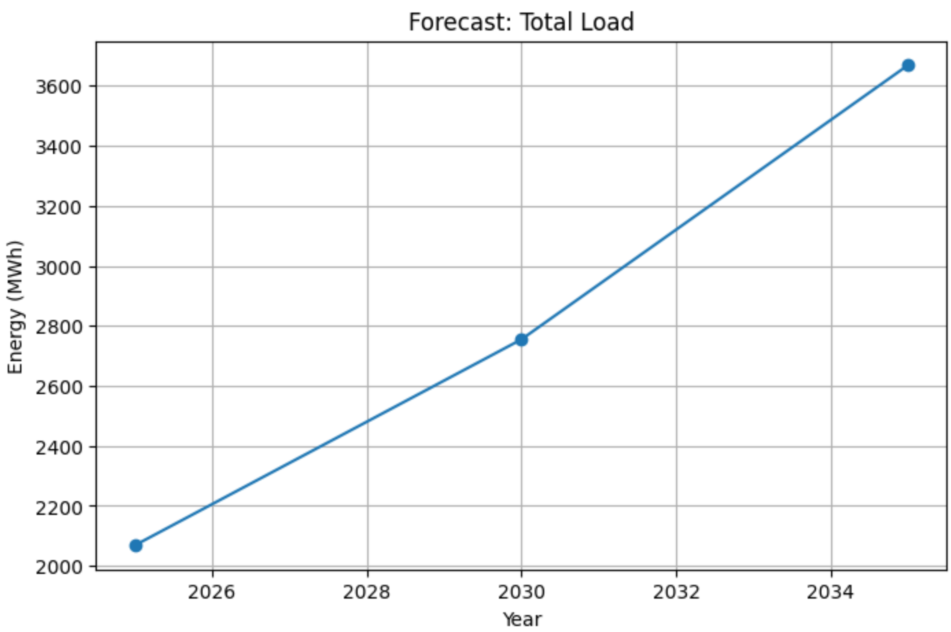

Figure 27. Forecasted yearly load consumption of 02_ Porkholm

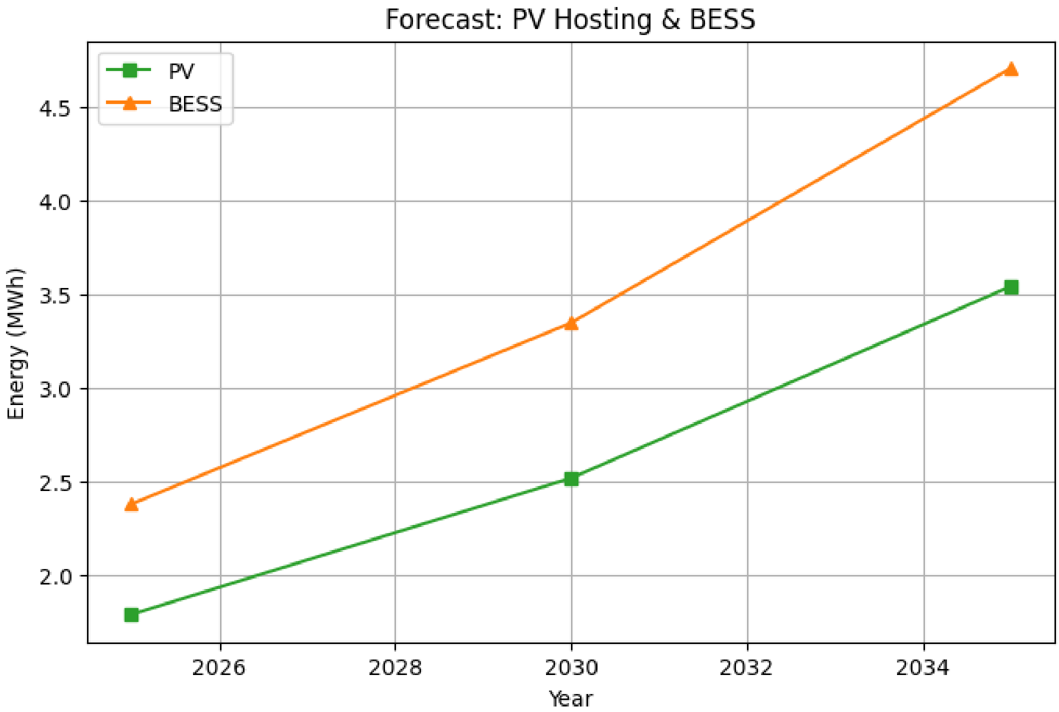

Figure 28. Forecasted yearly load PV generation and battery energy storage system of 02_ Porkholm

If these national trends are extrapolated to the Porkholm and Centrum networks, the implications are significant. For example, assuming a 5.9% compound annual growth rate, the 1953.11 MWh annual consumption in Porkholm could rise to over 3000 MWh within a decade, even without major industrial developments (Figure 27). Similarly, Centrum's load could surpass 2800 MWh annually, up from the current 1800.56 MWh (Figure 30). On the generation side, increased adoption of solar PV, biogas-fed microgrids, and possible small-scale wind installations will contribute to reverse power flows and greater volatility in net load profiles. These trends underscore the need for dynamic grid planning methodologies that can accommodate spatial and temporal variability in both load and generation. Figure 28 presents the forecasted yearly energy from PV generation and Battery Energy Storage System (BESS) for the 02_Porkholm network. In 2025, PV generation starts at approximately 1.8 MWh, while BESS capacity is around 2.4 MWh. By 2030, PV rises to about 2.5 MWh and BESS reaches 3.4 MWh. In 2035, PV is projected to grow to 3.55 MWh, and BESS to 4.7 MWh. This indicates steady growth in both solar generation and storage capacity, with BESS consistently leading in capacity.

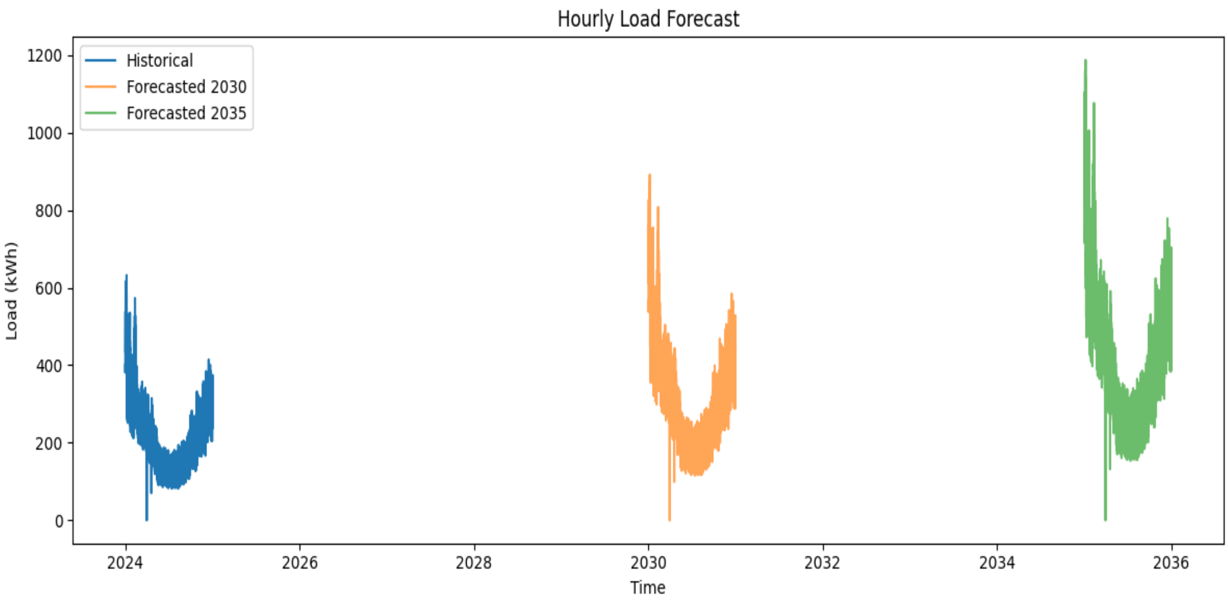

Figure 29. Hourly load forecast of 03_ Centrum network in 2030 and 2035

Figure 29 shows the hourly electricity load forecast for the 03_Centrum network in the years 2030 and 2035, along with historical data from 2024. The historical load (blue) in 2024 ranges between approximately 50 kWh and 650 kWh. In 2030 (orange), the load increases, reaching up to 900 kWh. By 2035 (green), the forecasted load further rises with peaks nearing 1200 kWh, showing significant growth. Overall, the data reveals a rising trend in both average and peak electricity demand over time. Figure 31 illustrates the forecasted yearly total load, PV hosting capacity, and BESS capacity for the 03_Centrum network. In 2025, the total load is approximately 1906.8 MWh, with 1262.9 kWh of PV hosting and 1944.2 kWh of BESS capacity. By 2030, the load increases to 2539.7 MWh, PV hosting reaches 1774.6 kWh, and BESS capacity rises to 2731.9 kWh. In 2035, all values continue to grow, with the total load at 3382.7 MWh, PV hosting at 2493.6 kWh, and BESS capacity at 3838.9 kWh. This shows a consistent and significant increase in energy demand and renewable infrastructure. Over the decade, the total load increases by 77%, PV hosting by 97%, and BESS capacity by nearly 98%. The data reflects a strong push towards integrating more solar generation and storage.

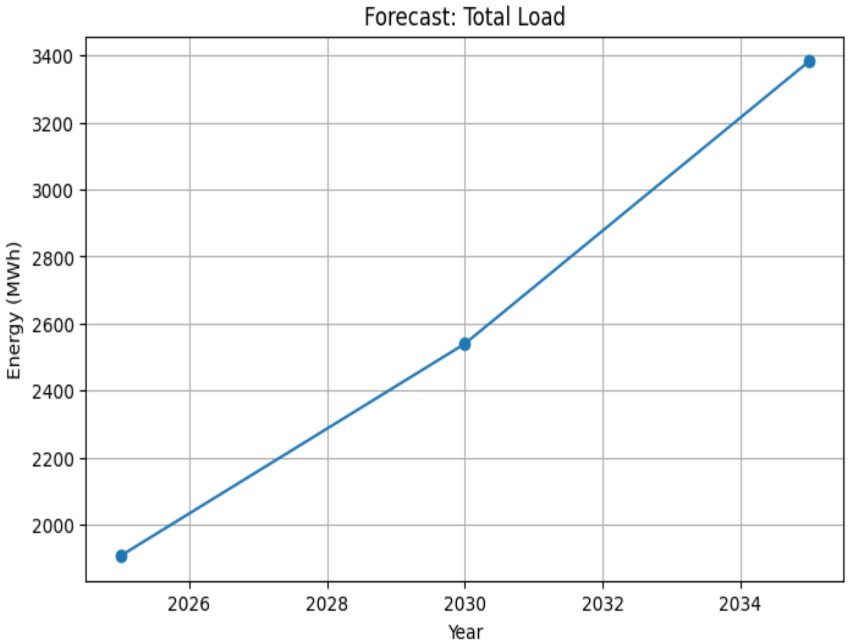

Figure 30. Forecasted yearly load consumption of 03_ Centrum

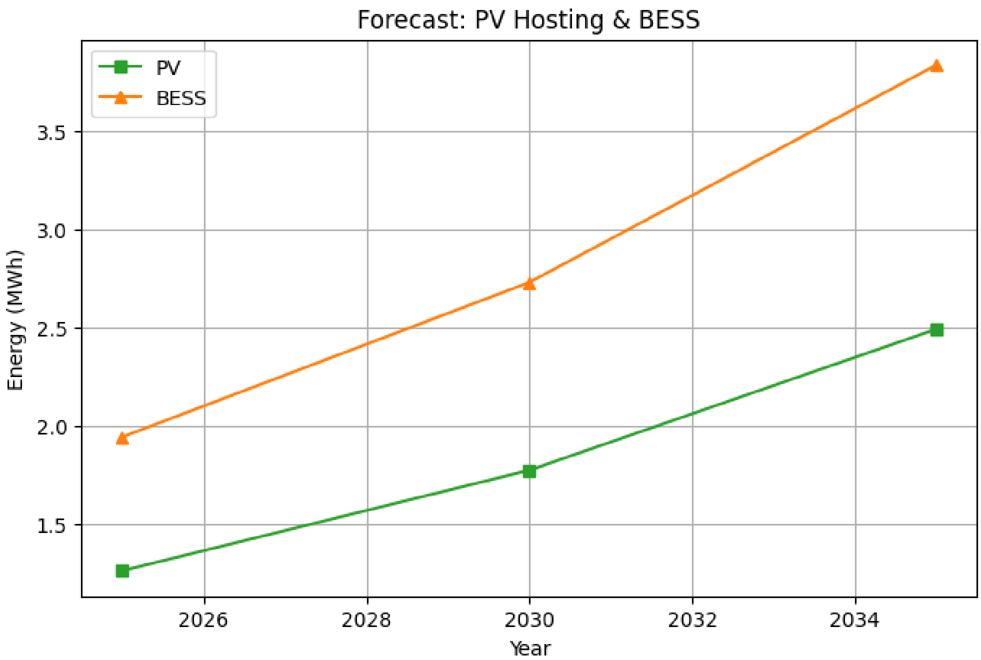

Figure 31. Forecasted yearly load PV generation and battery energy storage system of 03_ Centrum

6.2 Challenges and Constraints in Future Scenarios

Several technical and operational constraints will become more prominent as these projections materialize. Firstly, voltage regulation challenges will intensify, especially in the rural Porkholm network where long feeder lines are more sensitive to voltage fluctuations due to DER injections or sudden load changes. Secondly, transformer overloading and thermal constraints on feeders will be more frequent during winter months when heating demand peaks coincide with low solar generation. Without timely upgrades or flexible countermeasures, this could lead to increased occurrences of voltage violations, increased line losses and in extreme cases, forced curtailments of renewable generation.

Another critical concern is the temporal alignment between renewable generation and consumption. For instance, solar generation peaks during midday in summer, while peak consumption, especially from heating and EV charging typically occurs in early morning and late evening, particularly in winter. This mismatch needs energy storage integration and demand-side management, not just at the consumer level but also as part of the distribution operator’s long-term asset planning strategy.

6.3 Strategies for Resilient Grid Development

To effectively manage the anticipated growth and associated challenges, a multidimensional strategy must be adopted. This includes not only technical upgrades but also policy, market and stakeholder engagement components.

1. Flexible Grid Planning: Distribution System Operators (DSOs) should shift from traditional deterministic planning to scenario-based and probabilistic models that incorporate uncertainty in load, DER uptake and technology costs (G. & Edward J., 2024). Tools like hosting capacity maps, power flow simulations and Monte Carlo methods should be routinely used to guide decisions.

2. Digitalization and Smart Grid Deployment: Future-ready grids require real-time data, which demands investments in smart meters, grid automation and advanced data analytics platforms (Ishrat et al., 2025). These systems enable predictive maintenance, remote fault detection and better integration of DERs.

3. Energy Communities and Local Flexibility Markets: The establishment of energy communities, where groups of consumers and prosumers manage energy production and consumption collectively, could play a significant role in balancing local grids (de Jesus, 2024). Similarly, local flexibility markets can create financial incentives for consumers to adjust their behavior in ways that support the grid.

4. Strategic Storage Deployment: As detailed in Part 5, battery storage systems should be strategically sited to maximize their technical and economic value. They can serve as both grid deferral tools and market-enabling technologies, enabling participation in balancing services and energy arbitrage (McNamara et al., 2022).

5. Policy and Regulatory Alignment: National and regional energy policies must evolve to recognize and reward distribution-level flexibility. This includes tariff structures that reflect temporal and locational values, incentives for flexibility-enabling technologies, and regulatory sandboxes to pilot new business models (OECD, 2024).

6.4 Integration with Other Work Packages and Stakeholders

This work aligns directly with other work packages (WPs) of the PEAK project. WP1's results on hosting capacity, demand response, and optimal heating provide a foundational assessment for WP2, which focuses on modeling the impact of local energy systems, including microgrids and hybrid configurations. The identification of flexibility potentials and load shifting behaviors supports WP3, which develops business models and market mechanisms for activating demand-side resources.

Stakeholder collaboration is vital for implementation. The identified DR strategies for residential and retail segments, for instance, can be piloted in partnership with local DSOs, energy communities, and municipalities. The integration of smart grid solutions also aligns with Finland's national Smart Energy Programme and regional initiatives under the Vaasa Energy Cluster, strengthening the practical impact of the project. Furthermore, the European Commission's Clean Energy Package and the EU Strategy for Energy System Integration (2020) provide guiding principles that this study contributes to, particularly in promoting decentralized energy, sector coupling, and active consumer participation.

6.5 Future Research and Development Needs

Future research should focus on scaling up DR modeling, integrating real-time data, and simulating multi-vector energy systems (electricity, heating, mobility). This includes exploring machine learning for more adaptive demand forecasting and behavioral analytics, which can improve the granularity and accuracy of DR targeting (Chen, 2022). A critical research gap lies in the co-simulation of electricity and thermal networks, especially in regions like Ostrobothnia where electric heating dominates. Integrating heating flexibility with DR platforms can unlock further demand-side capacity (Carmichael et al., 2020).

In terms of technological needs, more field studies and pilots are required to evaluate grid-edge intelligence, such as decentralized control algorithms, home energy management systems (HEMS), and peer-to-peer flexibility trading (Chen, 2022). These tools align with international smart grid development frameworks such as those outlined by the IEA's Net Zero by 2050 Roadmap (IEA, 2021). Finally, close coordination with regulators and DSOs is needed to ensure that regulatory frameworks evolve to support dynamic tariffs, aggregators, and local energy markets (Papalexopoulos et al., 2020). The insights from this project provide a strong base to propose pilot schemes and regulatory sandboxes in the Ostrobothnia region.

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6.6 Conclusion

In conclusion, strengthening the resilience of the regional electricity network requires an integrated approach that combines renewable energy sources, flexible demand-side resources and advanced monitoring and management solutions. The distributed energy resources (DERs), such as rooftop solar PV and battery energy storage systems (BESS), can play a vital role in decentralizing energy supply and reducing dependency on centralized infrastructure, especially during peak load conditions or grid disturbances. The study of Porkholm and Centrum networks highlighted several critical nodes that can serve as optimal locations for renewable integration and localized storage, thereby improving voltage profiles and reducing losses.

Furthermore, demand response (DR) programs, particularly when tailored to residential and small commercial segments, can provide fast and cost-effective flexibility. These DR strategies not only help balance supply and demand in real time but also increase the grid's adaptive capacity during high-stress periods such as winter peaks. Probabilistic and rule-based disaggregation models used in this study enable targeted DR deployment by understanding appliance-level usage behavior.

Advanced monitoring and management systems, such as smart meters, grid edge controllers and distribution automation platforms are essential to enable two-way communication, real-time data acquisition and decentralized decision-making. These technologies allow dynamic adaptation to changing grid conditions and facilitate the integration of intermittent renewable energy. In the context of Ostrobothnia's regional network, these smart grid technologies can serve as enablers for transitioning from passive infrastructure to an active, flexible and resilient energy system aligned with national and EU-level carbon neutrality goals (European Commission, 2019; IEA, 2022). The collective implementation of these solutions (renewables, flexibility, and intelligent control) will ensure a more secure, sustainable and future-ready regional electricity network.

7 Overarching Conclusions

The findings of this report underline the urgent need for a proactive, integrated approach to grid planning and energy flexibility. First and foremost, demand response (DR) programs should be prioritized, especially in sectors such as agriculture, residential heating, public buildings and commercial retail, where the simulation results revealed significant potential for peak load reduction and cost savings. DR measures can be effectively implemented through time-of-use pricing, smart thermostats, and automated heating systems, particularly for customers with electric water tanks or heat pumps. Utilities and municipalities should consider launching targeted DR pilots in collaboration with local communities and aggregators to build trust, demonstrate effectiveness and scale up adoption.

Alongside DR, there is a strong case for investing in battery energy storage systems (BESS) as a physical flexibility resource. The sizing analysis shows that mid-sized systems ranging between 600 kW and 2200 kW depending on network characteristics can provide substantial benefits in terms of peak shaving, voltage regulation and deferral of costly grid reinforcements. These storage assets should be strategically deployed near substations or at the end of feeders where voltage support and congestion relief are most critical. Shared ownership models involving DSOs, municipalities or even community energy cooperatives could be explored to make these investments more feasible.

A fundamental shift towards data-driven and scenario-based grid planning is also necessary. This means embedding forecasting tools, load flow simulations and hosting capacity models into routine distribution network planning. Planners should not rely solely on historical averages but prepare for a range of future scenarios that reflect uncertainties in DER adoption, energy prices, weather patterns and policy changes. This approach will allow grid operators to remain agile and avoid both under- and over-investment in infrastructure.

As DER penetration increases, it is also essential to encourage grid-aware integration of renewable systems. New solar PV or biogas installations should ideally be accompanied by local flexibility assets such as batteries or controllable loads to prevent adverse impacts on voltage and power quality. Grid operators should provide clear guidelines and technical support to enable smooth integration, and smart meter data should be used to monitor the real-time impact of DERs on the system.

Long-term planning must address not only current operational bottlenecks but also the future increase in energy demand and local generation. Without proactive planning, the network risks fall short of the flexibility needed to meet future energy demands and decarbonization goals. Furthermore, there is a growing need to enable and support local flexibility markets where end-users, aggregators, and storage operators can be financially compensated for grid-supporting actions. While Finland's national regulatory framework is still evolving in this regard, pilot projects can be initiated to explore market design, participation rules and digital platforms that allow seamless communication between grid needs and available flexibility. These markets would not only enhance system efficiency but also empower consumers to play a more active role in the energy transition.

Interdisciplinary stakeholder collaboration must also be strengthened. The work of Task T1.2 links directly with other parts of the PEAK project, including system optimization (WP2), community engagement (WP3), and policy support (WP4). Municipalities, local utilities, technology providers, and research institutions should work together to co-create energy strategies that reflect both technical realities and social aspirations. Community workshops, digital dashboards and participatory planning tools should be used to adopt inclusive and transparent decision-making processes.

Lastly, as the distribution grid becomes increasingly digitalized, it is critical to invest in cybersecurity and system resilience. The deployment of smart meters, remote controls and cloud-based analytics platforms opens new vulnerabilities that must be addressed through robust security protocols, access controls and staff training. At the same time, resilience planning should include measures to deal with extreme weather events and grid disturbances, especially in rural and exposed networks like Porkholm. By building on these insights and actively implementing the proposed measures, the region can move toward a smart, decentralized, and participatory energy system that supports local goals while contributing to Finland's national climate targets. The methodologies developed and applied here also offer a replicable model for other regions facing similar challenges, highlighting the importance of interdisciplinary, data-informed planning in the era of distributed energy systems.

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