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Roles of flexibility measures in a regional electricity power system: Stationary batteries, V2G, and flexible hydrogen

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ABSTRACT

Flexibility in energy systems entails measures that support the efficient integration of weather-dependent electricity generation (e.g., wind and solar). This paper investigates the roles of flexibility measures, such as stationary batteries, vehicle-to-grid (V2G), electricity trade, and flexible production of hydrogen in a future regional electricity grid. The study employs the RESYST techno-economic model, which co-optimises investment in and dispatch of generation, storage, and conversion technologies such as electrolysis and heat pumps, with high spatial and temporal resolutions, with test case a region of western Sweden in Year 2050. The results reveal that it is cost-efficient to meet most of the demand using local generation together with storage units as flexibility measures. Stationary batteries and V2G compete in serving similar roles in a regional electricity system, where the deployment of batteries diminishes as diffusion of V2G increases, yet batteries prevail in areas with large deployments of local generation (wind and solar) and access to transfer electricity towards other areas. Batteries and V2G alleviates local congestion points and manage local variations within the region, as they can be discharged during times of low local generation, then to deliver electricity to other parts of the region. With high-level deployment of wind and solar power and the possibility to trade with other parts of the region, flexible hydrogen production is cost-effective, despite the additional costs for overcapacity and storage that it entails.

1. Introduction

To comply with the targets described in the Paris Agreement [1] and to achieve energy systems with net-zero carbon dioxide emissions, substantial efforts are required from various sectors. Such efforts include increasing the penetration of the renewable electricity supply (RES) and industrial decarbonisation through electrification [2,3]. The European Union has approved a set of initiatives to achieve climate neutrality in 2050 [3]. In Sweden, a climate law was enacted in 2018 that contained a national strategy to combat climate change and achieve net-zero emissions by Year 2045. The law and the targets act at different administrative levels, such as counties and municipalities [4,5]. With this in mind, it is imperative to align the need for future RES and decarbonisation with the current energy system conditions and to investigate the cost-efficient composition of the future energy system.

In Europe, specifically in Sweden, regions are positioned between national and local levels, allowing regions to assume the role of “intermediary”. Regions typically encompass several distinct areas such as industrial activities, populated areas, and rural areas. This emphasises their significant role in the energy transition, especially in cases involving the implementation of climate and energy transition policies such as electrification and decarbonization of power sector [6,7]. Realising the energy transition requires appropriate energy system planning, as the future increases in RES and electrification will impact electricity system in regions, which is represented by sub-transmission electricity system. Using a proper energy system planning tool, challenges connected to regional electricity system can be evaluated. These challenges include weather-dependent variations in generation and congestion within the regional electricity system. They can be tackled using flexibility measures, which include technologies such as energy storage, electric vehicles (EVs), flexible electricity generation, and flexible hydrogen or heat production which is commonly termed as Power-to-X (PtX).

Energy system modelling (ESM) is a tool used in energy systems planning to generate insights into the supply and demand of energy within a certain geographical scope over a selected period of time [8]. Previous work [9] employed PyPSA-Eur to highlight the benefit of utilising both transmission lines and hydrogen networks to achieve future

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European net-zero energy systems. Bødal et al [10] investigated the feasibility of off-shore hydrogen production through electrolysis in the North Sea using a multi-carrier ESM framework, EnergyModelsX, and found that off-shore hydrogen production is cost-efficient under conditions of high electricity price. Brandes et al [11] utilised REMod to study a transformation of the German energy system from the perspective of the federal states, i.e. modelling the local production within the states and electricity connection between states through transmission network, where they found that heat pumps, gas turbines, and transmission network are essential for balancing the electricity demand and supply from RES. Nagel et al [12] used the Balmorel model to compare the impacts of V2G as a flexibility measure to price volatility and the costs of operation in the system for nations with high penetration of variable renewable energy (VRE), such as Denmark, and for countries with high levels of flexible electricity generation, such as Norway. They concluded that V2G could play a role in reducing price differences between different power regions, moreover, increasing penetration of RES. A regional integrated ESM, OPERA, was employed by Sahoo et al [13] to study the northern Netherlands; the model results showcased the importance of regional modelling to complement regional policy making. Gupta et al [14] employed city energy modelling with the TIMES framework to model long-term energy system development in the city of Gothenburg; they highlighted the competition between electricity and biomass in realising future city energy systems. These studies underline the importance of tailoring ESM to a specific geographical scope, suggesting that this would also be the case when investigating the roles of flexibility measures in regional electricity grids. However, regional energy system studies typically do not include a representation of the regional, sub-transmission electricity system.

Studies have investigated the impact of flexibility measures on the different levels of energy systems. Schöninger et al [15] demonstrated the potential of heat pumps in Austria to provide short-term flexibility, such as shifting the electricity demand and reducing the curtailment of wind and solar power generation. Ghaemi et al [16] investigated the possibility of using electrolysis as a PtX measure in the case of green hydrogen for reducing congestion in distribution grids, given the high penetration of RES, as applied to the northern region of The Netherlands. They found that investment in electrolysis was profitable when high levels of RES were present in conjunction with incentives from grid operators. A study conducted by Holweger et al [17] of a low-voltage distribution system demonstrated that distributed flexibility was more profitable than grid reinforcement, where battery usage was included as one of the means of distributed flexibility. Venegas et al [18] noted that EVs had the capability to provide services to Distribution System Operators (DSOs) in terms of congestion management or voltage regulation, although challenges remained with EV adoption, such as the lack of regulatory frameworks and the uncertainty linked to the value of flexibility services provided by EVs.

Another instance, a study in [19] investigated the role of small and medium enterprises to provide demand-side flexibility in nation-wide German energy system, where the flexibility provision yields different impact to cost and CO_2 emissions reduction, while also promote renewable energy integration. Franken et al [20] found that there is a prominent interplay between flexibility provided by vehicle-to-grid (V2G) and electric heating with thermal storage in the Great Britain power system, where activation of flexibility in V2G counteracts the benefits provided by flexibility by electric heating and thermal storage. A work in [21] took the Norwegian system as an example and explored the role and value of end-use flexibility, concluding that end-use flexibility accelerates and increases local photovoltaic (PV) investments, although reduces the need for energy storages such as hydrogen and thermal. In a local scale, Song et al [22] showcased that EVs with V2G and Dynamic Line Rating (DLR) enhance wind power utilization in microgrids, despite the limited implementation of V2G due to EV idle time and owners' willingness to participate, while DLR requires upgrading existing infrastructures.

There have been studies and works that analysed regional electricity systems and included relevant flexibility measures, yet notable research gaps remain. Studies focusing on energy systems in a region have shown to employ simplified power systems physics, i.e. simplified power flow model [23–27] and to lack an accurate grid representation [28–31]. The power flows in energy system models are typically formulated as pipe flow or direct current (DC) power flow models and hence fail to capture the physical limits in regional grids due to lack of active and reactive power flows representation. Conversely, studies in regional power systems which represent detailed power flow physics oftentimes investigate solely dispatch problems [32,33]. Thus, there is a lacking body of research that accounts for both detailed energy infrastructure and detailed power system physics in investment planning and operation of a regional energy system model. Existing literatures have focused on planning and operation of integrated energy systems in regions but rely on simplified assumptions of the sub-transmission grid and thus fail to capture energy infrastructure barriers to a regional energy transition.

This study aims to close the research gap in investigating the roles that flexibility measures play in a regional electricity system using an energy system investment model with a detailed representation of the regional power grid. We develop and apply a Regional Electricity SYSTem model (RESYST), with the emphasis on the electricity infrastructure, encompassing regional grid sub-stations and power lines, accounting for both active and reactive power flows in the power system. The model is formulated as a total system cost-minimisation problem, i.e., the model endogenously determines whether it is more cost-effective to meet the demand through local production or to rely on imports from the national grid. Therefore, the roles of flexibility measures can be investigated through conditions that motivate cost-effective investments and operation of the flexibility measures. These conditions include access to local generation and imports from the national grid, the strength of the local electricity grid, and the possibility to meet sectoral demands in a flexible manner.

To summarize, the contribution of the paper is as follows:

- The paper presents a regional energy system model that is highly adaptable to other sub-national regions for broader applications.
- Conducts a realistic case study which takes of Western Sweden region as a case study, considering real-world regional electricity infrastructure.
- Depicts both active and reactive power to better represent the power system physics.
- Providing new insights into conditions in regional energy system that yield investment in stationary batteries cost-efficient.

The remainder of the paper is structured as follows. Section 2 provides the *Methods* that are used in the paper, including a description of the model and defined case studies. Results from RESYST are presented in Section 3, followed by a brief discussion in Section 4. Lastly, the findings and conclusions of the study are summarised in Section 5.

2. Methods

2.1. Model description

The RESYST model is formulated as a linear optimisation problem that co-optimises investment and operation decisions regarding generation, storage, and conversion technologies, with the objective of minimising the total system cost. We consider electricity sub-stations as nodes and power lines as a medium to deliver electricity between nodes in RESYST, while also accounting for the possibility to import electricity from the national grid. Each node has the obligation to fulfil electricity, heat and hydrogen demand in every time-step, with possibility to invest in generation and storage technologies, which will be detailed later. Among the included generation and storage technologies, several are considered as flexibility measures. Flexibility measures in the model encompass flexible generation (e.g., gas turbines) and storage (in this case batteries), as well as flexible operation of electrolysers and large-scale heat pumps. RESYST quantifies the cost-efficient deployment of selected technologies to fulfil the demands of the regional energy system. The dispatch levels of the generation technologies, storage technologies, and flexibility measures in every time-step are acquired, which can be used to investigate the role of flexibility. In addition, the spatial distribution of the deployment of technologies in the region can be assessed, to investigate how certain flexibility measures match certain nodal conditions in the region.

The RESYST model set-up is illustrated in Fig. 1, which also presents the model inputs and outputs. The regional scope is in the form of a regional electricity grid, with several sub-stations connecting the regional grid to the national grid. The sub-stations are treated as energy nodes, i.e., generation and demand from the surrounding areas are aggregated to the closest sub-station. Therefore, investment and operational decisions consider the amount of generation and demand in each node, with the possibility to transport electricity through power lines. Regarding the heating and hydrogen sectors, the nodal demand needs to be fulfilled locally, i.e., infrastructure such as pipelines is not represented. Importing from the national grid incurs additional costs that are dependent upon the electricity price during the corresponding period.

The objective of the model to minimise the system cost incurred due to the annualised costs of investments, operations, and electricity imports, as given in Eq. (1):

$$\min \sum_{i\in I}\Bigg[\sum_{x\in X}\left(C_x^{inv}+C_x^{fixom}\right)\cdot G_{i,x}+\sum_{o\in O}\left(C_o^{inv}+C_o^{fixom}\right)\cdot Y_{i,o} + \sum_{s\in S}\left(C_s^{inv}+C_s^{fixom}\right)\cdot E_{i,s}+\sum_{x\in X,t\in T}C_x^{op}\cdot g_{i,x,t}+\sum_{o\in O,t\in T}C_o^{op}\cdot y_{i,o,t} + \sum_{t\in T}\lambda_{i,t}\cdot\chi_{i,t}\Bigg] \quad (1)$$

The first term describes the total annualised cost of investments, which is dependent upon the investment cost (C^{inv}) and fixed operational and maintenance costs (C^{fixom}) of the: generation (G), conversion (O), and storage (E) technologies capacities. Generation technologies G comprise electricity technologies and heat-only boilers, whereas conversion technologies Y include large-scale heat pumps for heat production and electrolysers for hydrogen production. The second term describes the operational cost of the different technologies that are associated with fuel and variable operational costs (C^{op}). These cost components are multiplied by the dispatch of generation (g) and conversion (y). The final term provides the cost for electricity imports from the national grid, which is determined by the electricity price (λ) and the amount of electricity imported (χ).

The model includes more-detailed technical constraints, such as generation limits, storage levels, energy nodal balance, and power flow constraints. The complete model formulation can be found in the Appendix . The model is written in the Julia programming language [34] utilising the JuMP modelling framework [35], which is then solved using the Cardinal Optimizer (COPT) solver [36].

2.2. Region Västra Götaland

We apply the model to Region Västra Götaland (VGR), which is located in south-western Sweden, to investigate the roles of flexibility measures in the regional electricity system. The region includes many industries, including automotive, refineries, and chemical plants, which are all energy-intensive. The region, therefore, expects a strong increase in electricity demand in the future due to the electrification of these industries, as well as the up-coming battery-making factories. The electricity demand in Year 2045 may, therefore, be increased almost three-fold compared to the demand in Year 2023 [37]. Ackeby et al [38] have concluded that wind power (both on- and off-shore) and solar photovoltaic power can meet the increased demand, contributing annually with up to 45 TWh/a and 27 TWh/a, respectively. This implies that flexibility measures, such as energy storage units, flexible thermal generation plants, and demand-side flexibility will become increasingly important for balancing the electricity system.

In Sweden, a regional electricity system is referred to as a 'sub-transmission' system, which operates at a nominal voltage of 130 kV and is owned by one of the DSOs. Regional grids are typically connected to a much larger national grid, which operates at a higher voltage (≥220 kV) and is owned by the national Transmission System Operator (TSO). In practice, there are inter-changing electricity flows between the national and regional grids, so from the regional grid perspective, import of electricity is when the regional grid obtains electricity from national grid and export of electricity is vice versa.

The description of the regional grid relies on data for the topology and geographical distribution of the grid. However, obtaining actual regional grid data has proven to be difficult for various reasons, and this significantly hinders the accuracy of the model in accounting for a realistic power flow. To address this, we apply a method developed previously [39], which is based on the collection of regional grid data from an open source database. OpenStreetMap (OSM) [40] is the open geospatial database that was chosen for this work, from which we retrieved the regional electricity grid shown in Fig. 2

The left-hand side of Fig. 2 shows that there are 122 power lines in the regional grid, depicted as blue lines that represent the electricity connections between the nodes. Furthermore, there are 104 regional electricity sub-stations, indicated with coloured dots; in RESYST, these

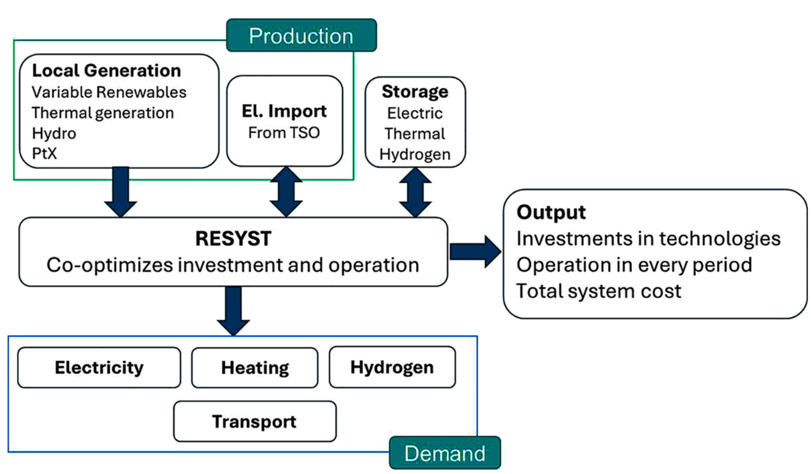


Fig. 1. Illustration of the model.

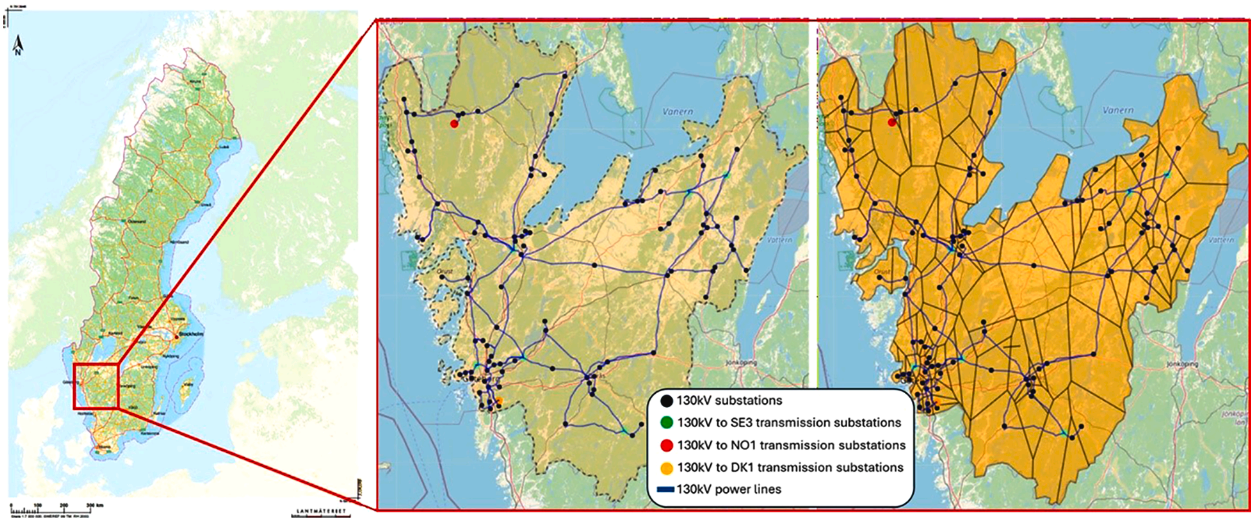


Fig. 2. (left) Map of Sweden, taken from Lantmäteriet [41], (middle) Region Västra Götaland, with electricity infrastructure from OpenStreetMap, and (right) polygons representing the Voronoi cells in the studied region.

sub-stations are considered as nodes. These nodes act as energy nodes, i.e., the generation, storage, and demand side are connected here. Among these 104 nodes, there are 8 import nodes, i.e., connection points to the national grid, presented as green, red or orange dots depending in which electricity price area the national grid resides. The region considered connects to three electricity price areas, namely SE3 (green) which is part of Sweden, NO1 (red) which is part of Norway, and DK1 (orange) which is part of Denmark.

In RESYST, each node covers an energy demand and generation capacity for a specific area in the region, defined using Voronoi cells. These Voronoi cells are used for the following purposes: (1) accounting the potential capacities for wind and solar power as defined below; and (2) providing the distribution of technology investments, demand, and generation in the region.

2.3. Model inputs and assumptions

2.3.1. Weather year

In this work, the RESYST model employs a single weather year of 2019 for hourly VRE generation and demand profiles. Although relying on single weather year may reduce the robustness of the model, the demand profile used in this work is derived from actual electricity and heat demand measurements for Gothenburg in Year 2019. Given the advantage of employing real measured demand data for a specific year, we use the same weather year for VRE generation to maintain consistency.

2.3.2. Exogenous electricity prices

The profiles for the different price areas determine the costs of importing electricity to the VGR. These electricity price profiles are based on the marginal cost of electricity from a north European capacity expansion model, as applied previously [42]. The north European capacity expansion model uses information such as wind speed, solar irradiance levels, and demand profile from Year 2019, with costs assumptions depicting a future Northern European energy system in Year 2050.

2.3.3. Generation and storage technologies

The techno-economic data for electricity generation, conversion, and storage technologies applied in this work are taken from [43–45], where cost approximations for Year 2050 are used. Furthermore, a discount rate of 5% is used to compute the annualised investment costs. The following technologies are considered in the model:

Electricity generation: OCGT, CCGT, biomass CHP, waste CHP, on-shore wind power, far off-shore wind power (floating), near off-shore wind power (anchored), photovoltaic (PV) roof-top, ground-mounted (utility) tracking PV, and hydropower. Hydropower is not allowed for further investment and is limited to its current annual electricity generation output of 2 TWh.

Energy storage: Stationary batteries, EV batteries (V2G), pit thermal heat storage (PTES), tank thermal heat storage (TTES), hydrogen tank storage (HTS), and hydrogen lined-rock cavern storage (LRC). Specifically in the case of stationary batteries, the technology is split into power and energy components, with different cost structures.

Hydrogen production: Proton Exchange Membrane (PEM) electrolysis.

Heat generation: Electric boilers (EB), gas boilers (HOB), heat pumps (HP), and biomass heat-only boilers (Bio HOB).

It is worth noting that in this study, PEM electrolysis and HP are considered as PtX, as they allow flexible production of hydrogen and heat from electricity. Moreover, bioenergy is used as fuel in OCGT, CCGT, CHP, and gas boilers.

The maximum potential of the installed capacity in each node for VRE generation (on-shore wind power, off-shore wind power, photovoltaic roof-top, and ground-mounted tracking photovoltaic) is derived using a tool developed by [46], and then applied to the corresponding Voronoi cell indicated in Fig. 2. It is noteworthy that Far and Near Off-shore Wind have different eligible nodes with different potentials, i.e., Far Off-shore Wind has higher potential in the region compared to Near Off-shore Wind. The potential for Near Off-shore Wind is obtained from [46], whereas that of Far Off-shore Wind is from [47]. It is assumed that Far Off-shore Wind can only be deployed along the west coast and in the two large lakes to the north and east (see Fig. 2).

The hourly electricity generation profiles for the wind and solar generation technologies are retrieved from Renewables Ninja (https://www.renewables.ninja) [48,49]. The VRE generation capacity potentials and profiles are dependent upon the locations of the nodes described in the previous sub-section.

2.4. Demand

The RESYST model represents the electricity, heating, and hydrogen demands. The electricity demand for Year 2050 is derived from the expected future electricity demand for Year 2045 in [37,38], with the demand distribution for each municipality obtained from the Statistics Sweden [50]. The heating demand for each municipality in Västra Götaland assumes a level similar to today's demand, and is retrieved from Statistics Sweden [50], whereas the future hydrogen demand is based on a previous work [51]. The demand for each municipality is then distributed equally according to the number of nodes within the municipality, yielding an annual nodal demand. For municipalities that do not have nodes, the demand is aggregated to the geometrically closest node. The hourly demand profiles for electricity and heating are derived from actual electricity and heating demand measurements for Gothenburg in Year 2019. Due to the limitations associated with the demand profiles in other municipalities, the profile of Gothenburg is applied uniformly to the entire region, i.e., all nodes have a similar hourly load profile but differ in terms of the amplitude of the demand.

The future hydrogen demand described in [51] originates from industries that are expected to undergo electrification. Thus, the hydrogen demand is assumed to have a flat hourly demand profile. Despite this, the electricity demand for hydrogen production through electrolysers will vary depending on the extent to which it is cost-efficient for the model to invest in hydrogen storage and over-capacity in electrolysers. The annual electricity, heat, and hydrogen demand in each Voronoi cell are given in Fig. 3, which shows that the electricity demand in the region is highest along the coast. In contrast to the electricity sector, the infrastructures for the heat and hydrogen sectors are not represented, so the demand for heat and hydrogen in the model is met through local heat and hydrogen generation.

2.5. Regional grid

In the current work, regional grid expansion and reinforcement is not considered, i.e. regional grid maintains its existing topology with the assumed power line capacities. Under this assumption, the model will find cost-efficient way to meet the demand even under congestion, by utilizing local generation and flexibility measures, therefore highlighting the roles that different measures will take. Due to the limited knowledge of the actual grid capacity, it is assumed that each power line has current carrying capacity of 1,500 A.

Eight import nodes are considered in the model. Six of these are connected to the Swedish national grid, one to the Norwegian national grid, and one to the Danish national grid. The import nodes have an inherent capacity that limits the hourly import or export level between the regional and national grid. This total inherent capacity is based on [37], and currently the limit corresponds to 3,200 MW of import/export for all import nodes. Since the actual import capacity of each import node is unknown, it is assumed that the total import limit is the same for all the import nodes, yielding 400 MW of capacity for every hour in each import node. There is a plan to increase the regional import/export limit to 5,600 MW [37].

For readability, the key modelling assumptions are summarized in Table 1.

Table 1
Summary of key modelling assumptions.

Model parameters	Assumptions	Remark/taken from
Weather Year	VRE generation profile and demand profile use 2019 data	
Techno-economic cost data	Assumes 2050 costs from Danish Energy Agency catalogues	[43–45]
Discount rate	5%	
Electricity demand	Assumes Year 2045 demand, amounting to approximately 60 TWh/yr	Demand level from [37,38], with municipal distribution from [50]
Heat demand	Similar level as today	[50]
Hydrogen demand	Approximately 14 TWh/yr, with hourly flat profile	[51]
Hourly demand profile	Gothenburg 2019 profile applied uniformly across nodes	Actual electricity and heat demand measurement
VRE potential	Maximum potential in each Voronoi cells that can connect to nodes	[46]
VRE profile	Hourly generation profile	Renewables Ninja (https://www.renewables.ninja) [48,49]
Regional grid	No expansion and reinforcement, 1,500 A of current carrying capacity for power lines	Topology from OSM, with assumed current carrying capacity
Import nodes	8 nodes; 6 from Swedish national grid, 1 from Danish and Norwegian national grid each	OSM
Import capacity	3,200 MW total, split uniformly to 400 MW per import node, with planned increase to 5,600 MW	[37]

2.6. Investigated cases

2.6.1. Main cases

Table 2 summarises the four cases investigated in this study. The cases investigated are linked to various uncertainty factors that may impact the development of the future regional electricity grid. These factors include the future projected electricity demand, regional subscription limit, and possibility of V2G.

Currently, around 70% of the 18 TWh/a electricity demand of the region investigated are linked to imports from the transmission grid. The future electricity demand amounts to approximately 60 TWh/a, according to the future demand projections described in [37,38]. With an existing import capacity from the transmission grid of 3,200 MW, this gives a self-sufficiency level for the region of 46% (28 of 60 TWh/a). Grid reinforcements resulting in an increase in the import capacity to 5, 600 MW are considered [37], since the possibility to import electricity may have a substantial impact on the results.

In order to investigate the roles of flexibility measures in regional

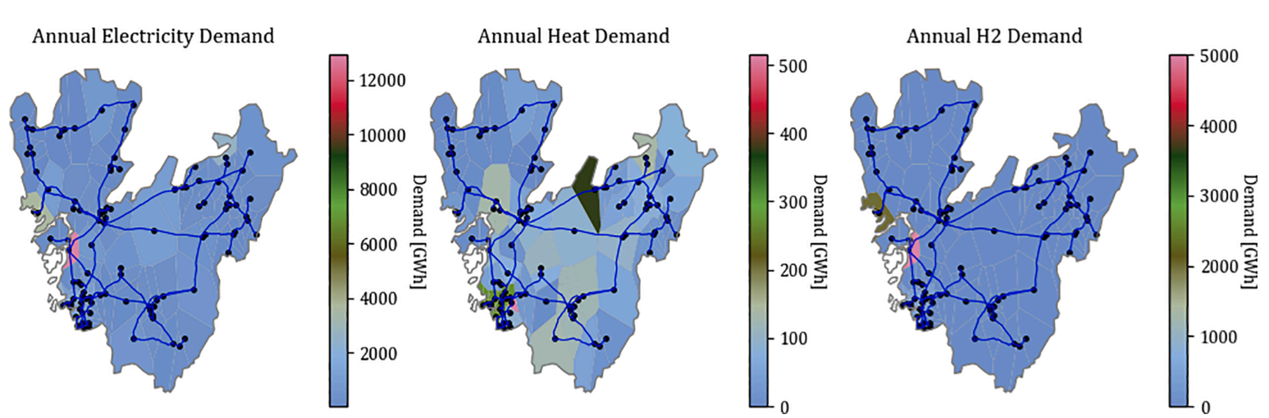


Fig. 3. Annual demand distributions in Year 2050 for: (left) electricity; (middle) heat; and (right) hydrogen.

Table 2
List of cases investigated.

Case name	Import limit [MW]	Possibility of V2G	Rationale
DIR-LIM	3,200	No	Low diffusion of V2G TSO faces a delay in increasing import capacity
DIR-HIM	5,600	No	Low diffusion of V2G TSO fulfils the increased import commitment
V2G-LIM	3,200	Yes	Considerable diffusion of V2G TSO faces a delay in increasing import capacity
V2G-HIM	5,600	Yes	Considerable diffusion of V2G TSO fulfils the increased import commitment

electricity grids in a specific node, we sub-divide the nodes in the regional grid into demand, generation, and transfer nodes. Generation nodes refer to nodes with substantial generation, which means that they are net exporter of electricity in annual basis, whereas demand nodes are net importer annually. Transfer nodes refer to nodes that have similar levels of net export and import.

We evaluate the roles that storage measures will play in the future energy system, based on the average hourly demand coverage. The hourly coverage is computed according to Eq. (2), which expresses the ratio of storage deployment to the hourly average demand in each node, corresponding to its sector.

$$\xi_{i,s} = \frac{E_s}{\frac{1}{T}\sum_{t=1}^{T} D_{i,t}^{act\ or\ H2\ or\ Heat}},\ \forall i \in I\ \forall s \in S \tag{2}$$

2.6.2. Sensitivity analysis

V2G provides an additional measure of demand-side flexibility. However, this measure is uncertain as it relies on the willingness of the users to apply V2G which will depend on electricity contracts as well as to what extent it is implemented as a usable option by the vehicle manufacturers. Nevertheless, in the modelling it is assumed that by Year 2050, the entire private vehicle fleet will be electrified, with the possibility of a share of the fleet being available for V2G. The number of private vehicles in each municipality is based on Statistics Sweden [50], whereas the representation of private EVs in the model is taken from previous work [52]. Moreover, to investigate the impact of different levels of V2G diffusion to the other forms of flexibility measures in the systemic level, a sensitivity analysis has been undertaken by varying the share of EV fleet that is available for V2G as given in Table 3 with 20% chosen as the reference case in this work.

3. Results

This section starts with an overview of the results on an aggregated level, in terms of the annual electricity generation per technology and the total annual imports and exports of the region given the different levels of import capacity. Thereafter, the spatial deployments of selected technologies are presented, to show where the measures are most cost-efficiently located in the regional grid. Lastly, the role of flexibility in the future regional electricity system is investigated by examining specific time periods, to understand how flexibility interacts with generation and load levels in the system. It should be noted that unless otherwise stated, cases V2G-LIM and V2G-HIM in the figures refer to 20% V2G diffusion.

Table 3
Levels of V2G diffusion for sensitivity analysis, bolded shows reference value.

The share of EVs available for V2G				
10%	**20%**	30%	40%	50%

3.1. Annualised electricity generation and import levels

The electricity generation mix in Year 2050 for VGR, as obtained from the modelling of the four investigated cases, is depicted in Fig. 4, which shows the annual electricity generation mix, including the annual net electricity import levels from the national grid (TSO).

It is evident that there are only small differences in the electricity generation mix between the four cases, and that in all cases, it is cost-efficient to meet the annual demand from local generation, although some imports from the national grid are still required. This highlights the capabilities of the region in terms of self-sufficiency in the different investigated cases. The annual electricity generation is mainly supported by wind power plants, which comprise on-shore, far off-shore, and near off-shore wind generation. Among these wind power technologies, on-shore wind generates 21.7–22.0 TWh of electricity, followed by far off-shore wind, which provides 15.8–17.1 TWh of the annual electricity generation. Near off-shore wind has the lowest level of electricity generation among the included wind power technologies, amounting to 4.5–4.7 TWh. This is in accordance with the potentials of the different wind power plants in the region, whereby on-shore wind has the highest potential.

Photovoltaics provide annual electricity generation of 3.7–3.9 TWh for utility PV and 2.7–2.9 TWh for roof-top PV. Solar PV generation is substantially lower than wind power generation, which highlights the unique condition of VGR, in that the region has particularly good wind conditions but more-modest solar insolation. Although hydropower is available in the region, the annual electricity generation is limited to 2 TWh annually, which explains the constant level of annual generation in all the studied cases.

Thermal power plants, such as GTs and CHPs, contribute less to the annual electricity generation than renewables or imports from the national grid. Among the thermal power plants, Biogas OCGT provides the smallest contribution at less than 0.01 TWh of annual electricity, while Waste CHP generates 0.1 TWh. Biogas CCGT contributes with an annual electricity generation of 0.5–0.9 TWh. Lastly, Biomass CHP provides the highest share of thermal generation with 1.3–1.6 TWh of annual electricity. Based on the annual generation levels of the thermal power plants, it is clear that the higher generation from CHPs is because CHPs act as the base load, which stems from the low cost for the fuel, i.e., biomass. In contrast, GTs serve as peak power plants, due to their high fuel cost. Moreover, CHPs have a dual use, since they can generate both electricity and heat, whereas GTs can only generate electricity.

Fig. 5 (left-hand side) depicts the region's annual exports and imports from the national grid, whereas the right-hand side illustrates the amounts of annual imports at all the import nodes. The annual net imports are in the range of 4.9–7.0 TWh, i.e., the net import of electricity is approximately 8%–12% of the annual electricity demand. The model assumes that in low import cases (DIR-LIM and V2G-LIM), imports from the national grid are limited to 3,200 MW, amounting to 28 TWh of the maximum possible import level for the region in 1 year. As for the high import cases (DIR-HIM and V2G-HIM), the maximum possible import level is 49 TWh annually. Therefore, the region utilises between 47.8% (13.4 of 28 TWh) and 35.9% (17.6 of 49 TWh) of the maximum annual import capacity in the low and high import cases, respectively. The annual net import distribution indicates that net importing nodes are located in proximity to demand centres (see Fig. 3), i.e., in the south-western and north-eastern parts of the region.

Despite the possibility to meet a large share of the annual electricity demand with imports, it is found to be cost-efficient to invest in local generation for a large share of the electricity demand. The model results also show a reduction in electricity imports with the introduction of V2G as a demand-side flexibility measure; the electricity imports for the DIR-HIM and V2G-HIM cases are 7.1 TWh and 6.5 TWh, respectively. The reduction in imported electricity when including V2G suggests that, with available low-cost flexibility, it is more cost-effective to invest in or dispatch more local generation.

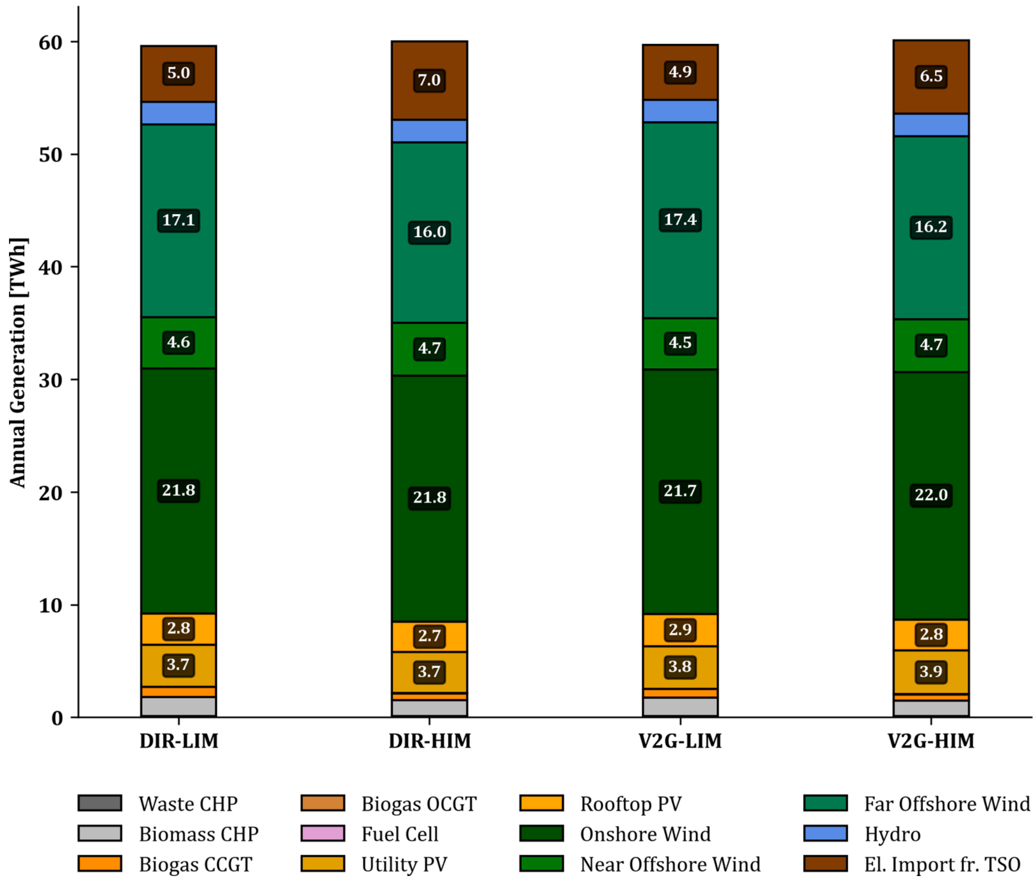


Fig. 4. Electricity Generation Mix in Region Västra Götaland in Year 2050, as obtained from the modelling of the four cases listed in Table 2.

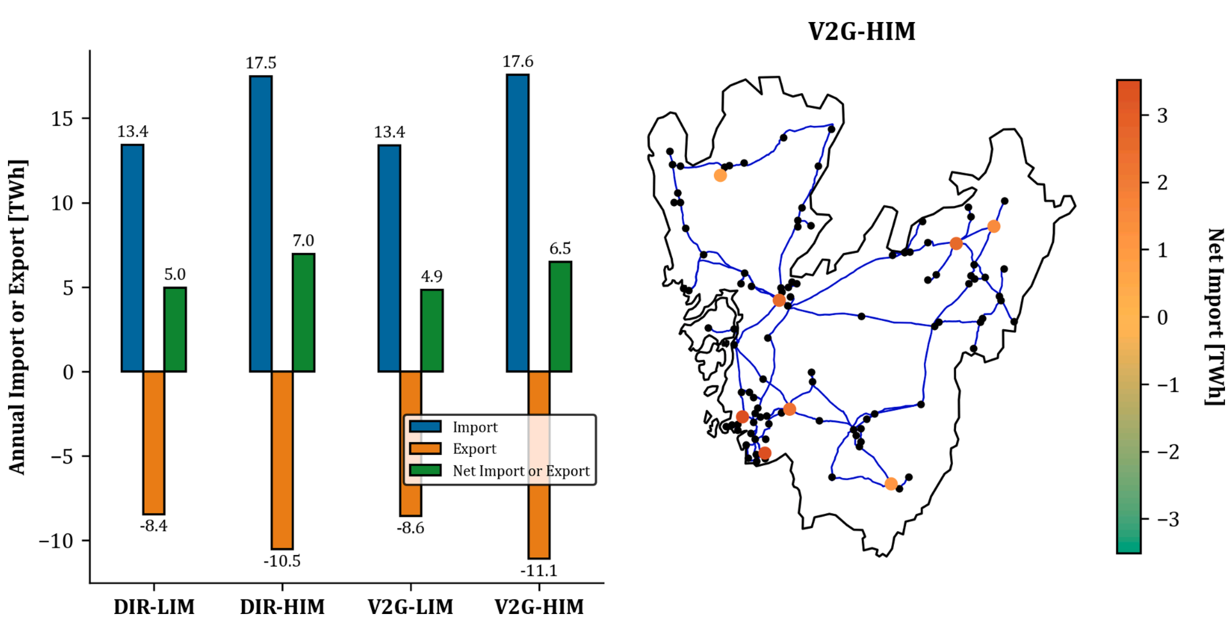


Fig. 5. Annual levels of exports from and imports and net imports to the region, as obtained from modelling the four investigated cases (left), and the levels of net imports from import nodes in the V2G-HIM case (right).

3.2. Spatial deployment of electricity generation and storage

Spatial deployment for both on-shore wind and utility PV in VGR is presented in Fig. 6

Fig. 6a shows the deployment of on-shore wind, which exhibits that region Västra Götaland has generally favourable wind conditions, and on-shore wind power is therefore distributed across the whole region, notably with higher deployment in the southern, north-western, and north-eastern parts. In comparison to on-shore wind, Fig. 6b shows that the installed capacity for utility PV is more contained, with utility PV deployed mainly in the central and north-eastern parts of the region. Although not shown, off-shore wind units (near and far) are deployed

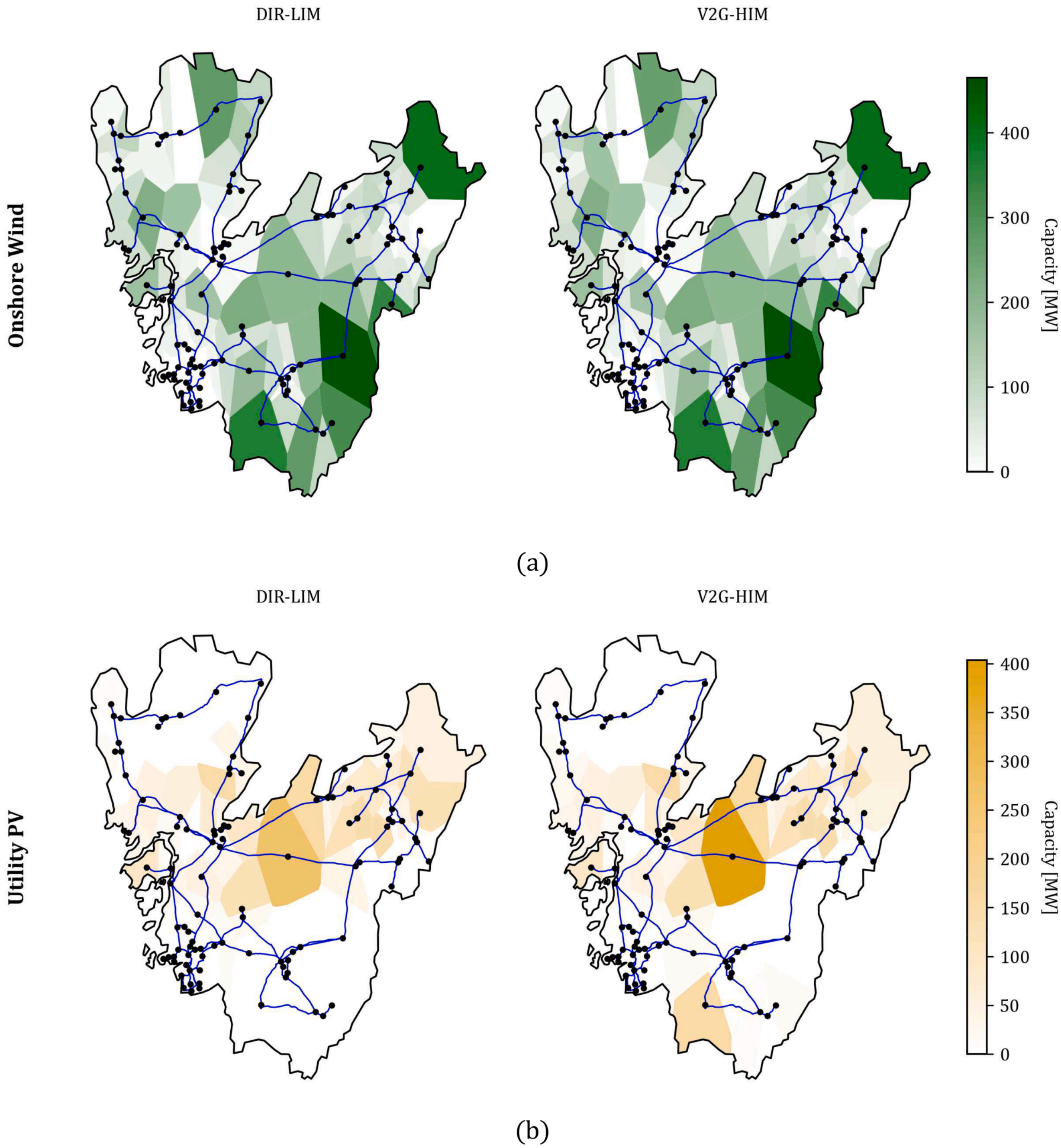


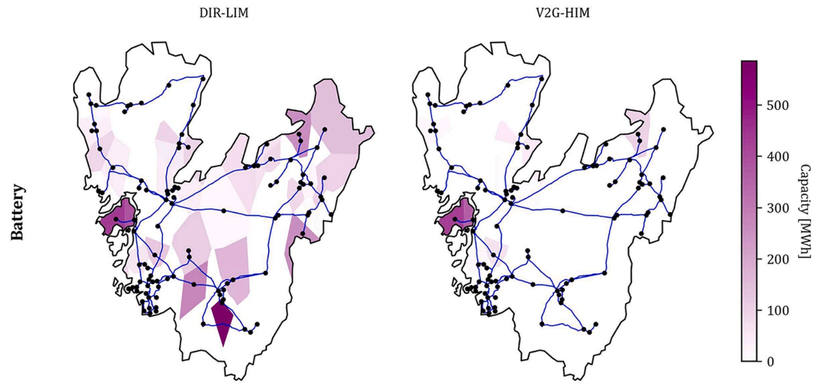
Fig. 6. Deployment patterns of on-shore wind (a) and utility PV (b).

along the western coast of the region, yet exclusively close to demand centres (interested readers are directed to the Appendix for further details).

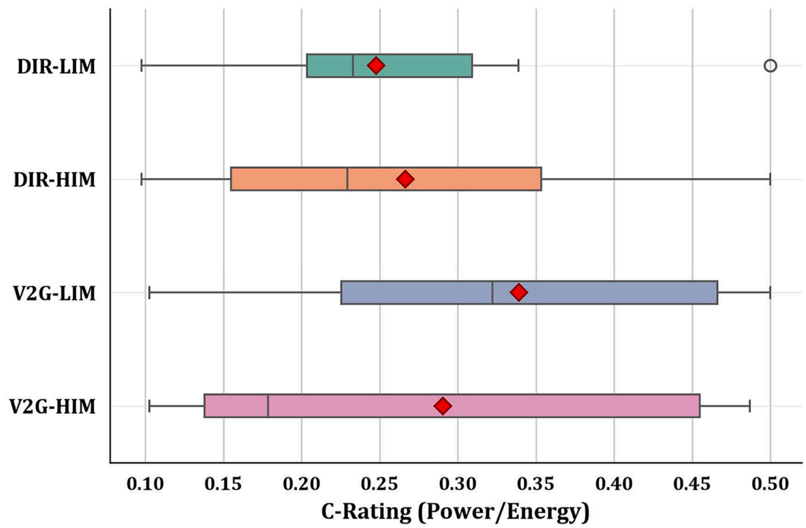
Fig. 7 presents the spatial deployment of stationary batteries and the distribution of the C-ratings across the four investigated cases. In the DIR-LIM case, batteries are shown to be distributed throughout the region, with the most-pronounced concentrations in the western, southern, and north-eastern parts, with capacities that amount to more that 500 MWh in the western part, where investments in on-shore wind and utility PV are found. V2G as another means of electricity storage is distributed according to the number of vehicles in the corresponding Voronoi cells.

From the deployment of generation technologies, it is evident that utility PV is deployed at locations where on-shore wind deployment is lacking, e.g., the central part of the region. In contrast, in the southern part, there is high deployment of on-shore wind power yet almost no deployment of utility PV. The reason for this is that wind power is the lowest-cost option for electricity generation in the region. Once it is not possible to invest further in on-shore wind power, the model proceeds to exhaust the utility PV resource as the second-best solution. Therefore, one can conclude that low or non-existent utility PV deployment signifies that on-shore wind and trade with other nodes can meet the local electricity demand, while the presence of utility PV indicates that local and imported on-shore wind power sources are not sufficient to meet the nodal load.

The C-ratings of stationary batteries across the different cases indicate that batteries are cost-efficient investments for handling short-term (i.e., intra-day) variations. The C-rating spans 0.1–0.5, which indicates that batteries are the most-beneficial tools to manage variations that last from 2 to 10 hours. When comparing the V2G-HIM and DIR-LIM cases,



(a)



(b)

Fig. 7. Deployment patterns of stationary batteries (a) and distributions of C-rating of batteries across all the investigated cases (b). Red diamond symbols indicate the mean C-rating values in each case.

the deployment of batteries is replaced by V2G, which can be explained by the preferential low-cost flexibility. This, however, does not apply to the western part of the region.

3.3. The role of regional batteries – stationary and EVs with V2G

3.3.1. Deployment of batteries in relation to nodes characteristics

The distribution of stationary batteries in regional system is presented in Fig. 8, which depicts the distribution for all cases under different node categories. The horizontal axis in Fig. 8 indicates the level of annual net import of a node, i.e. demand node, whereas the vertical axis shows the level of annual net export, namely generation node. The area around diagonal dashed line presents the transfer node, with similar levels of annual net import and export.

The distribution of stationary batteries in Fig. 8 showcases that the placement is highly correlated to generation and transfer nodes, with the highest capacities of more than 500 MWh are shown to be in generation nodes with net annual export of 1.25 TWh or transfer nodes with equal amounts of export and import, e.g. around 0 TWh and 1.5 TWh. The remaining smaller stationary batteries capacities are mostly distributed in transfer nodes, with exceptions of stationary batteries located in demand nodes with net import of 1.8 TWh. In comparison to stationary batteries, the distribution of V2G is predetermined by the number of vehicles in the nodes, therefore no clear indication of whether V2G is placed in generation, demand, or transfer nodes.

The distribution highlights the role that stationary batteries play in

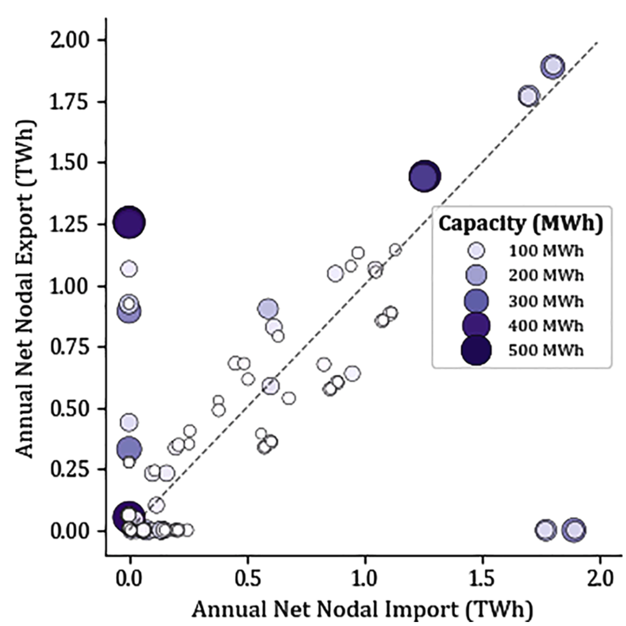


Fig. 8. Distribution of stationary batteries in exporting or importing nodes for all the investigated cases.

the region. The cost-effective deployment for stationary batteries is found in generation and transfer nodes, implying that stationary batteries are cost-effective measures in maintaining power delivery to other nodes.

3.3.2. Alleviating local congestion

Following the placement of stationary batteries and V2G with respect to node characteristics, it is of interest to examine the instances of charging and discharging of stationary batteries and V2G in regional electricity system.

Fig. 9 depicts the charging-discharging probabilities of stationary batteries and V2G under different levels of line utilization. The probabilities are presented in histogram, with bins indicating the levels of line utilization in 10% steps. The probabilities presented here are the normalized number of hours where charging and discharging activities in a specific node occur, in accordance with the loading of power line(s) connected to that node.

The probability histogram for stationary batteries, shown in Fig. 9a, exhibits a bimodal pattern, where the highest probabilities with a total of 21% charging-discharging activities occur when the line is loaded at 90-100%, i.e. under congestion. The second highest probability of charging-discharging activities occur when the line is loaded at 0-10%, corresponding to around 16%.

In contrast, the probability for V2G activities in Fig. 9b presents a skewed right pattern, except when the line is loaded at 90-100%. It is shown that the probability of charging-discharging of V2G is lower than stationary batteries, where the highest is at 13%, compared to 21% of stationary batteries when the line is loaded at 90-100%.

The probabilities of batteries activities regarding line loading showcases the role of batteries in the form of stationary batteries and V2G in alleviating congestion, where the operation probability is the highest during high line loading. This trend of operation applies to both stationary batteries and V2G, despite the different levels of probability, hence both measures take similar roles in regional system. Furthermore, stationary batteries and V2G demonstrate a high probability of operation when the line is loaded at very low level. Instances where periods of low line loading occur during periods of low local generation, where the production are used to meet local demand, hence there is not much power to deliver to other nodes, leading to low line loading. This signifies the role of batteries and V2G in managing local variations, specifically due to variations in local generation.

To better understand how stationary batteries and V2G play these roles, we look at the electricity generation, storage levels, and power flow profiles from the RESYST model in selected nodes. Fig. 10 depicts the locations of three connected nodes, ORU1, ORU2, and STE1, and the power lines connected to these nodes. STE1 is a node with high electricity and hydrogen demands (see Fig. 3), whereas ORU1 and ORU2 are nodes in which there is deployment of wind, solar, batteries, and V2G (*cf.* Fig. 6 and Fig. 7). ORU1 acts as a generation node and ORU2 positions itself as a transfer node, connecting ORU1 and STE1, whereas STE1 is a demand node.

Fig. 11 presents the hourly levels of the electricity generation and power flow from the ORU1 which is a generation node. The power flow represents the electricity flow in lines that are connected to ORU2 (L75). The value is positive when the node is delivering electricity and negative when it is receiving electricity. The electricity demand (black line in Fig. 11 top panel) consists only of the inherent electricity load, then the excess generation is either delivered to other connected node, used to produce heat with HP, or used for charging electricity storage units.

From Fig. 11, the ORU1 node delivers electricity to ORU2, indicated by power flow of L75, while it also locally generates electricity, mainly from on-shore and near off-shore wind power during the period shown. As the local demand is much lower compared to local generation, the excess of electricity is delivered through L75.

It is shown in Fig. 11 that batteries and V2G are being discharged whenever there is a lack of local generation, while periods with high local generation are being utilised to charge stationary batteries or V2G. In the example of Hours 460 to 480, there is a lack of local generation, in which stationary batteries and V2G are discharged to meet the local demand. Due to this limitation, there is also very low electricity being delivered through L75. This occasion corresponds to roles of stationary batteries and V2G to manage local variations during low line loading, indicated earlier in Fig. 9.

In the example of Hours 630 to 650, the node is in condition of high local generation, however, L75 is almost at capacity, to which stationary batteries charges, utilizing the amount of local generation. V2G does not shown to provide similar service, which can be explained by the limitation of driving pattern during these periods. One can also notice that stationary batteries and V2G operate similarly, i.e. discharge together in some hours, demonstrating stationary batteries and V2G take similar roles in alleviating local congestion.

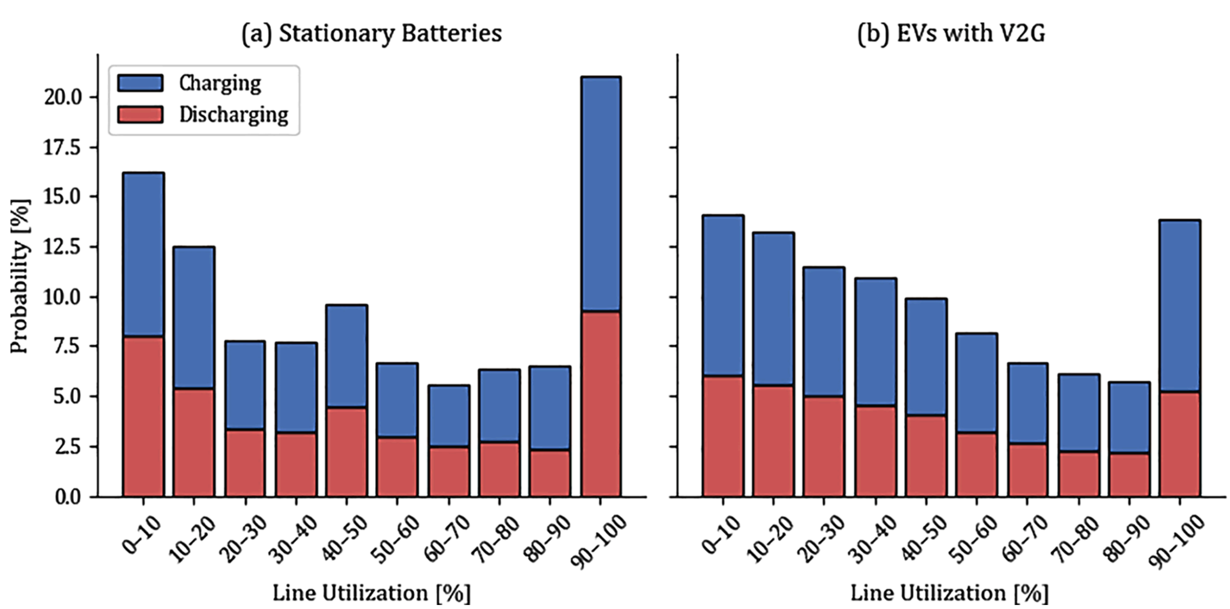


Fig. 9. Probability of charging and discharging of stationary batteries (a) and EVs with V2G (b) under different levels of power lines utilization for all investigated cases.

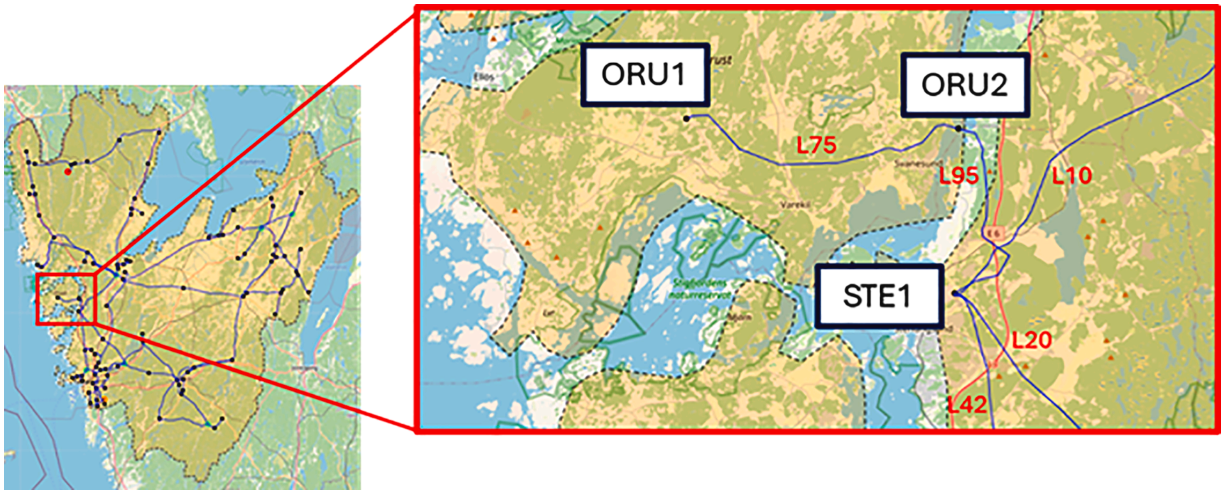


Fig. 10. Locations of the ORU1, ORU2, and STE1 nodes, with power-line connections L10, L20, L42, L75, L95.

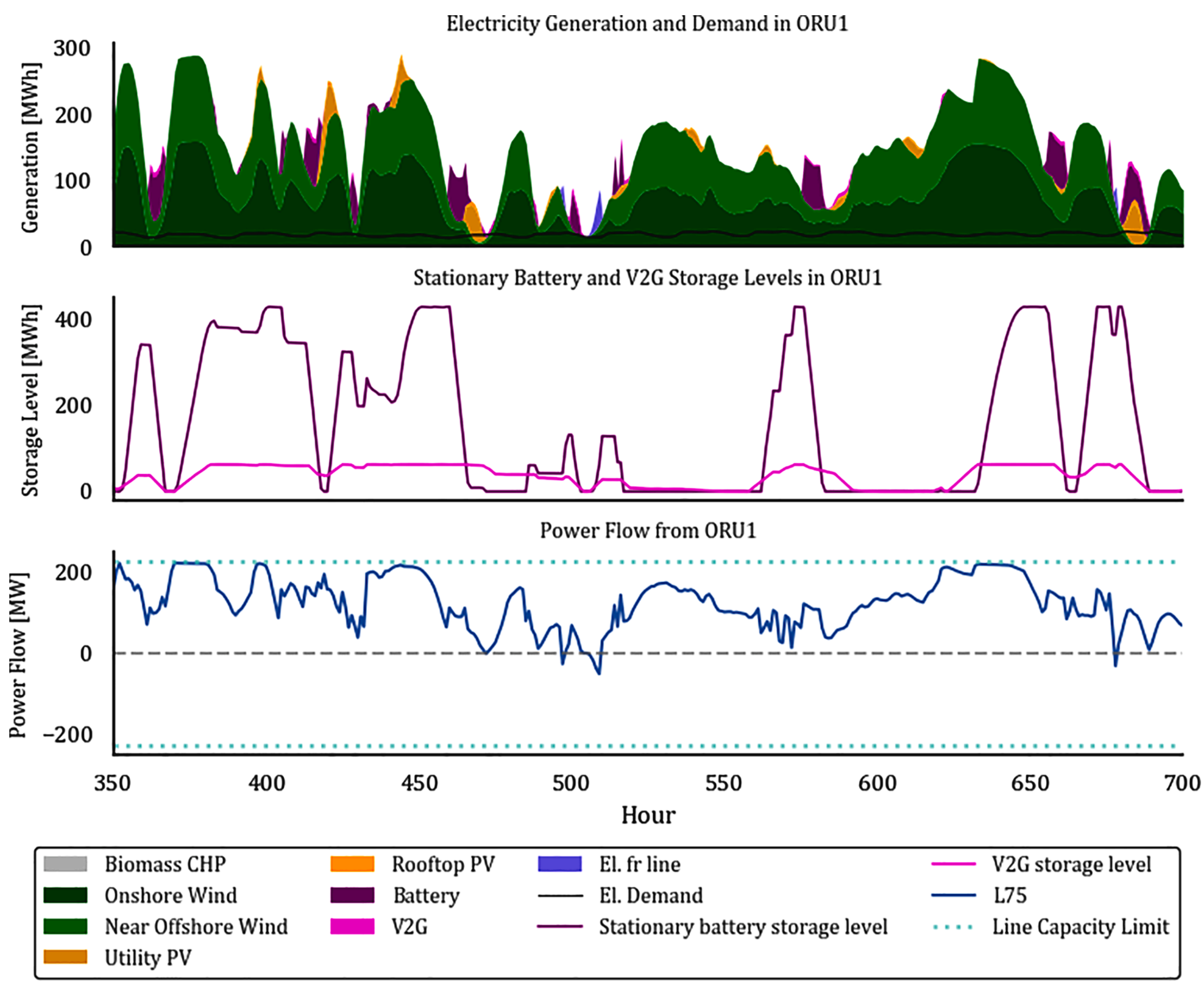


Fig. 11. Two-week dispatch profiles of V2G-HIM case in the ORU1 node with the use of stationary batteries and V2G, and the power flows on the associated power line L75.

3.4. *Multi-day storages and flexible hydrogen production as measures*

Fig. 12 provides the distributions of the number of hours during which the different storage technologies can cover the average hourly demand in each node for all the cases investigated. The red diamonds indicate the mean values, whereas the circles are the outliers in the respective technologies.

The distribution shows that batteries are sized to cover intra-day variations, where the mean coverage of electricity demand by batteries is 6.1 hours, aligns with batteries C-rating demonstrated earlier. In

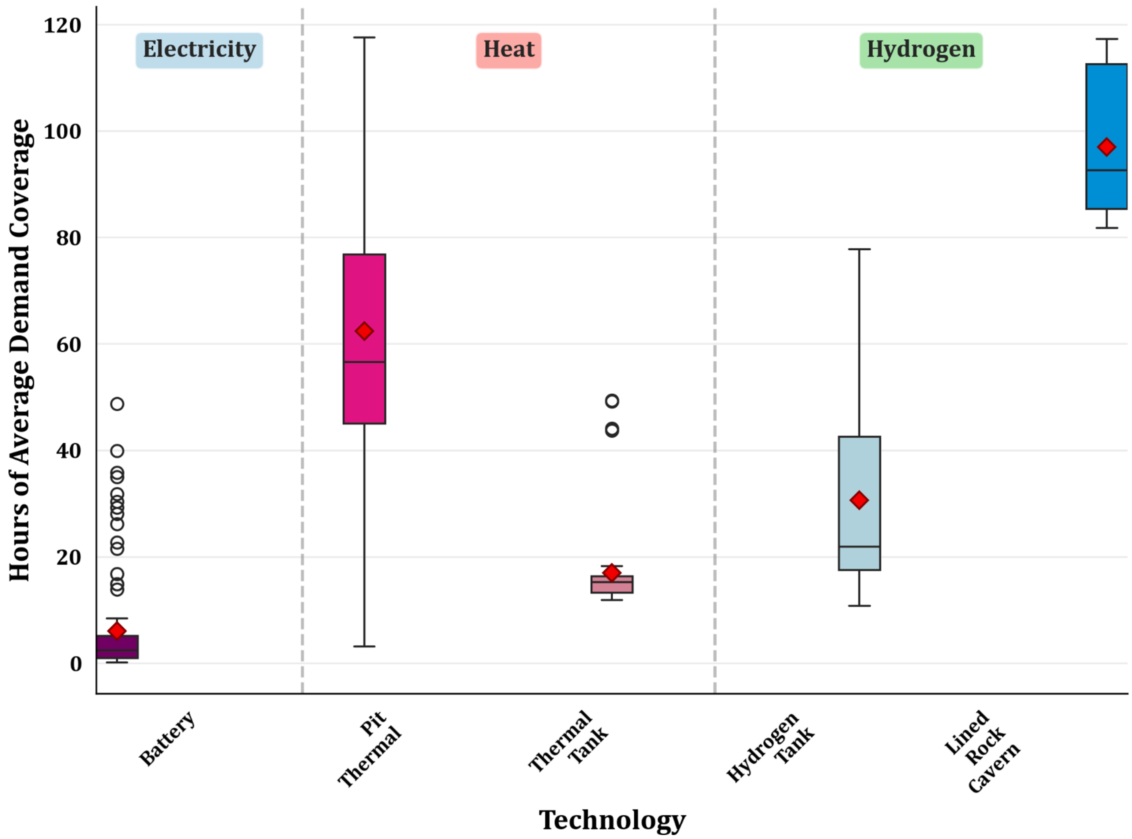


Fig. 12. Distribution patterns of the demand coverage of the different storage technologies in all the nodes, as obtained from the modelling for all the cases investigated.

comparison, the heat and hydrogen storage units are sized to manage multi-days variations, with mean demand coverages of 62.4 hours for PTES and 96.9 hours for LRC. The tank storage alternatives, i.e., TTES and HTS, are shown to be sized corresponding to 0.5–1.5 days of variations.

Fig. 13 depicts the electricity generation, electrolyser – LRC operation, and electricity price in the STE1 node over the year. As can be seen, the operation of the electrolyser is more affected by local production than by the electricity price, as shown in Hour 4,750-5,250, where the electrolyser is operated at lower level due to the lack of local generation, yet this operation is possible as the hydrogen production is supported by discharge from LRC. LRC is charged during periods of low electricity prices, as shown around Hour 6,000 when the LRC level increases sharply during low electricity price.

3.5. Impact of V2G share

A sensitivity analysis has been conducted to identify the impact of V2G share in the regional electricity system as a demand-side flexibility to other flexibility measures that require investment decisions.

Fig. 14 illustrates how the share of V2G vehicles influence deployment of the other flexibility measures for the low import case (a) and the high import case (b). With an increased share of V2G vehicles, the deployment of batteries is reduced, underlining the competition between batteries and V2G at a system-level. In low import availability, at the highest level the deployment of batteries is 4.5 times higher compared to the reference case, with the lowest is 0.3 times compared to the reference case, i.e. 73% reduction. The deployment in the high import case shows a less pronounced impact on batteries, with maximum of 2.0 times battery deployment with no V2G down to 0.4 times at 50% V2G.

The other measures are all insensitive to the V2G share except for OCGT which increases significantly when V2G is not available (1.6 times the reference), specifically when import is more limited. This implies that OCGT play the role of managing variations in periods and locations where neither batteries nor access to import is not available. There is only a weak influence from V2G share on the capacity of CCGT, which is expected considering its high investment cost as well as its fuel cost, thus taking a different role than managing variations (base load). The same goes for the other technologies which vary between 0.9–1.1 times reference case for the V2G shares investigated. As can be seen, battery deployment is around twice as high in the low import case compared to the high import case, which shows that for the electricity prices investigated, import/export from the transmission grid can compete with batteries in managing variations.

4. Discussion

The study takes as an example the future regional electricity system in Västra Götaland, with the aim of investigating the role of flexibility measures in regional electricity systems. The results show that the region has good conditions for wind and solar power generation, which will meet most of the demand in a cost-efficient way. The high levels of solar and wind power generation, as compared with the outputs of thermal power plants, such as CHPs and GTs, imply that it is more cost-effective to meet the demand through renewables in combination with flexibility measures. It is important to note that the amounts and the locations of solar and wind power deployments are motivated by the benefits that they provide to the system, i.e., reducing the total system cost. This is not the case in reality, where the deployment is also driven by the potential to harness profits for electricity generation owners.

The present study shows that increasing the electricity import capacity does not necessarily mean that the regional demand can be met by imports. The modelling shows that given the price profile of imported

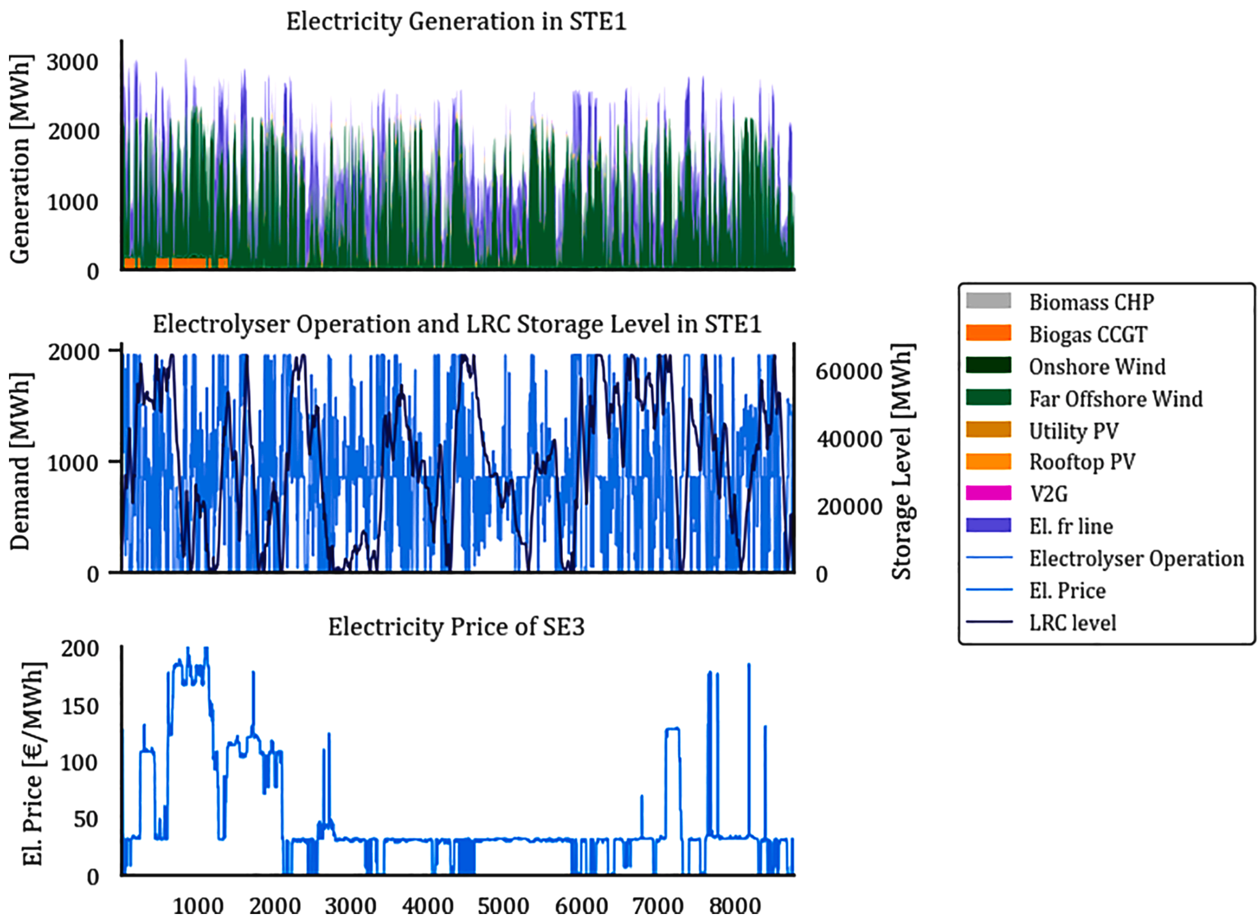


Fig. 13. Operational dispatch and electricity prices in STE1 for 1 year.

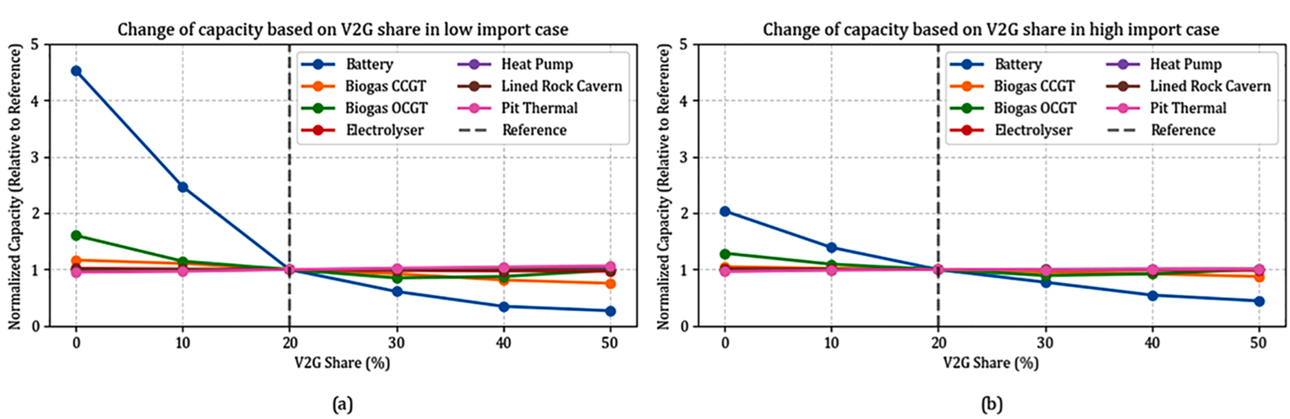


Fig. 14. Deployment in flexibility measures under different V2G diffusion in low (a) and high (b) import.

electricity, cost-efficient imports contribute less than 15% of the annual energy needs across all the study cases. Thus, for the assumptions applied, it is cost-effective to make use of generation within the region instead of importing from national grid. Although there are numerous import nodes in the region, the good conditions for wind and solar power within the region and the high level of power-line utilisation in the regional grid diminish the value associated with importing electricity.

Regarding electricity storage, stationary batteries and V2G serve similar roles of managing variations and alleviating congestions during high power line loading. Stationary batteries represent an active decision in the model, which incurs a cost, whereas V2G is a demand-side and demand-driven flexibility technology, i.e., it is available as a low-cost flexibility option. This leads to different conditions and enablers in which the batteries and V2G play their roles in the modelled regional electricity system.

Stationary batteries strive and available in generation and transfer nodes, characterized with high levels of deployment of wind and solar power for generation nodes, and located close to demand centres and in proximity of import access for transfer nodes. Stationary batteries distribute the power from high wind and solar generation events across multiple hours, so as to match the local load. The modelling shows that stationary batteries can manage local congestion, by charging from excess local generation when the power lines are highly loaded. This also leads to the possibility for electricity storages to maintain the level of power delivery between nodes during congestion, from generation nodes to demand or transit nodes during periods of low local generation.

In comparison, V2G is pre-determined by the number of EVs, the level of V2G diffusion, and their owner's willingness to participate in providing flexibility. When V2G is available, the model sees this as an inherent flexibility that can replace batteries. Yet, driving patterns limit the functionality of V2G, such that V2G primarily manages intra-day variations, for which charging occurs during night-time. The hourly generation levels show that V2G takes on the role of managing variations in a more-confined area, i.e., in a specific node due to vehicle availability and driving profile limits, whereas batteries are shown to manage variations in wider areas.

From the presented results, the deployment of batteries is enabled by the possibility to store a large amount of the excess generation, as indicated by the high level of local generation in, and the possibility of interplay with other flexibility measures. Moreover, this competitiveness is exemplified by the deployment of batteries with response to different levels of V2G diffusion, whereby most of the batteries are rendered ineffective once V2G is introduced to the system. The competitiveness of batteries and V2G in system-wide level is demonstrated by the deployment of batteries that is inversely proportional to the level of V2G diffusion.

Flexible hydrogen through electrolysers, alongside their respective storage facilities indicate different sizing principles, which demonstrate the different roles that these measures could play in a future regional electricity system. The result shows that the main determinant for electrolyser operation is the availability of electricity, which can be provided by local generation or through electricity trade from other nodes. It was mentioned earlier that the model does not consider grid expansion nor reinforcement, therefore the cost-efficient way to meet hydrogen demand is through overcapacity of hydrogen generation technologies and provision of storage. The electrolyser is slightly oversized such that it can both meet the hydrogen demand and fill a storage unit during times of low-to-medium electricity prices. These findings emphasise the importance of strong electricity connection to hydrogen demand centres, i.e. ensuring access to electricity in periods of low local generation. PTES and LRC are proven to be suitable for sizing as multi-day or weekly storage systems, which serve the purpose of managing longer variations, which is caused by wind rather than solar variation.

Although this study employs a model that depicts a highly detailed regional system, it has several limitations and is subject to several uncertainties. The study is applied to a region with high industrial activities, specifically industries with expected hydrogen demand due to electrification, which can be very specific, therefore the specific findings in this study may be different if the study were to be done in regions with different characteristics. Nevertheless, this enhances the need to undergo region-specific energy systems modelling, aligns with the findings by Hasan et al [53], where they concluded that different regions present different costs associated with technologies and variations in weather, which impact the capacities of storage and generation technologies. As previously noted, the included single weather year and electricity price may compromise the robustness of the model and thus leaves room for future work. Jafari et al [54] highlighted that investments decision based on single-year can lead to suboptimal decisions under different weather years. Gøtske et al [55] have highlighted the importance of including several weather years in planning future infrastructure, as the cost may varies when capacity mix under single weather year is tested under different weathers. Ruggles et al [56] argued that it requires at least 40 weather-years to design a robust energy systems with high wind and solar penetration. Yet, the findings by [57] indicate that the extreme weather years variations do not necessarily impact the share of electricity from renewables.

The flexibility options could be expanded by introducing pipelines to transfer hydrogen between areas with hydrogen demand and the potential produce hydrogen in locations with cheap access to electricity and then transmit through pipelines. Previous works [9,24,58] have shown that the total system cost in a selected geographical area can be reduced by having greater flexibility in the hydrogen sector through the use of a hydrogen pipeline. DLR could also be introduced as a flexibility measure in the system, as shown in the work of Büttner et al [59], and discussed extensively in the work by Zhang and Teh [60], specifically in how DLR and V2G open new possibilities in grid flexibility enhancement by adapting to wind variations, reduce reliance on fossil fuel, and mitigating temporal supply and demand imbalances. The model considers that the electricity power lines in the region remain the same in Year 2050, so as to enable a detailed representation of the power grid while keeping the model convex. Potential expansion and reinforcement of power lines in the regional electricity systems should also be included in the model in future work, as power lines are one of the crucial flexibility measures and may affect the need for increased capacity and deployment of generation and storage technologies. Lastly, capturing the national grid that spans the region of interest in future work could provide a better understanding as to whether electricity imports are limited by specific parts of the power system.

5. Conclusions

A linear optimisation energy systems model (RESYST) is developed and applied to investigate the roles of flexibility measures in a future West Sweden regional electricity system. RESYST is a generation and storage capacity expansion model with high geographical resolution and a detailed representation of the sub-transmission power grid. Four main cases are investigated, with different levels of import to the region and the possibility of V2G implementation in the region. The findings of this study provide cost-efficient investment and dispatch in generation technologies and flexibility measures of a future regional electricity system under regional electricity grid limitations.

The results show that it is cost-efficient to meet most of the annual demand in the region investigated through local production, specifically wind and solar power, along with flexibility measures that shift the energy supply over time. In the studied region, wind and solar power accounts to more than 80% of annual electricity production across all investigated cases, showing their cost-effectiveness in meeting the annual demand. Electricity imports contribute to the small fraction of meeting the annual demand (8-12 %) regardless of import capacity, This highlights the cost-effectiveness of meeting the demand through local electricity production in region that hosts good conditions for wind and solar power, thus reducing reliance on import of electricity from national grid.

It is found that stationary batteries and EVs with V2G serve similar roles in a region, as the deployment of stationary batteries diminishes when V2G is introduced into the system. Results for the region investigated show that compared to Reference case where 20% EV fleet implements V2G, deployment of stationary batteries are 4.5 times higher when V2G is not available. Moreover, stationary batteries in the region are found to be deployed in: (1) generation nodes, characterised with positive net annual nodal export due to high local production and (2) transfer nodes, often nearby demand centres and access to import from national grid. Their deployment indicates that batteries and V2G in the region alleviate local congestion and manage local intra-day variations that are caused by generation and demand variations. This aligns with the operation (charging and discharging), as stationary batteries and V2G operate more often during low (0-10%) and high (90-100%) power lines utilization. In this context, low power lines utilization refers to low local generation, hence there is not enough power to be transferred to other nodes. On the contrary, high power lines utilization indicates the grid is congested, albeit locally.

Different storage technologies are sized to tackle different durations of variations in the region, spanning from intra-day to multi-days variations. Electricity storage units are shown to be cost-effective for mitigating intra-day variations, whereas heat and hydrogen storage facilities are sized to tackle multi-day variations. In the investigated region, electricity storage has a mean demand coverage duration of 6.1 hours, while pit thermal and hydrogen cavern storages covers 62.4 and 96.9 hours of mean demand respectively. Still, the operation of such hydrogen producing technologies and the respective storage units are mainly driven by the availability of electricity, rather than the electricity price.

The model developed in this work can help regional energy planners, regional network operators, and utility companies to evaluate regional electricity system investment and operation decisions to establish energy transition in the region, specifically through deployment of renewable electricity production. The findings provide an understanding how flexibility measures and renewable electricity production can interact to within a region to achieve a cost-efficient regional electricity system. The RESYST model can be improved further by implementing additional weather years that reinforce the robustness of the results and including more flexibility measures. The national grid and import bottlenecks could be investigated in detail by depicting national grid within the region in detail in the model. Specifically in regions that expect electrification in industry sectors with the use of hydrogen in processes, the model can be improved further by possibility of implementing hydrogen pipelines to transport hydrogen between demand centres.

Data availability

Data will be made available on request. The code for the model is available on https://github.com/pprianto/ResystVGR.

CRediT authorship contribution statement

Pandu Prianto: Writing – review & editing, Writing – original draft, Visualization, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Lisa Göransson:** Writing – review & editing, Supervision, Methodology, Formal analysis, Conceptualization. **Filip Johnsson:** Writing – review & editing, Supervision, Project administration, Funding acquisition.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper

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Appendix A

Nomenclature

Indices	
i	Node
x	Generation technology
o	Conversion technology (PtX)
s	Storage technology
t	Period
Sets	
I	Nodes
X	Generation technologies
O	Conversion technologies
S	Storage technologies
T	Periods
Parameters	
C_x^{inv}	Annualised deployment cost of generation technology x
C_o^{inv}	Annualised deployment cost of conversion technology o
C_s^{inv}	Annualised deployment cost of storage technology s
C_x^{fixom}	Annualised fixed operation and maintenance cost of generation technology x
C_o^{fixom}	Annualised fixed operation and maintenance cost of conversion technology o
C_s^{fixom}	Annualised fixed operation and maintenance cost of storage technology s
C_x^{op}	Fuel and variable operation cost of generation technology x
C_o^{op}	Fuel and variable operation cost of conversion technology o
$\lambda_{i,t}$	Electricity price on node i in period t
$\overline{G}_{i,x}$	Maximum deployment of generation technology x in node i
$\overline{Y}_{i,o}$	Maximum deployment of conversion technology o in node i
$\overline{E}_{i,s}$	Maximum deployment of storage technology s in node i
$\underline{G}_{i,t}$	Minimum deployment of generation technology x in node i
$\underline{Y}_{i,o}$	Minimum deployment of conversion technology o in node i
$\underline{E}_{i,s}$	Minimum deployment of storage technology s in node i
$\rho_{i,x}$	Generation profile (solar or wind) in node i of technology x
$D_{i,t}^{act}$	Electricity active power demand in node i period t
$D_{i,t}^{reac}$	Electricity reactive power demand in node i period t
$D_{i,t}^{\mathrm{H2}}$	Hydrogen demand in node i for period t
$D_{i,t}^{\mathrm{Heat}}$	Heat demand in node i for period t
η_o	Efficiency and Coefficient of Performance of conversion technology o
$e_{i,s,t}^{loss}$	Storage losses of technology s, at node i in period t
ς_s	Storage losses factor of technology s

(*continued on next page*)

(*continued*)

V_{nom}	Electricity system nominal voltage
$G_{i,j}$	Conductance of power line between node *i* and node *j*
$B_{i,j}$	Susceptance of power line between node *i* and node *j*
$\overline{S}_{i,j}$	Apparent capacity of power line between node *i* and node *j*
κ	Constant to constrain active and reactive power flow limits
τ^p, τ^q	Linearising parameters for active and reactive power components
$\alpha,\ \beta$	Maximum and minimum ratios of reactive power generation to active power generation
PF	Demand power factor
π	Voltage angle limit
Variables	
$\chi_{i,t}$	Import of electricity from national grid at node *i,* for period *t*
$G_{i,x}$	Deployment of generation technology *x* in node *i*
$Y_{i,o}$	Deployment of conversion technology *o* in node *i*
$E_{i,s}$	Deployment of storage technology *s* in node *i*
$g^{act}_{i,x,t}$	Active dispatch of generation technology *x* in node *i* for period *t*
$g^{reac}_{i,x,t}$	Reactive dispatch of generation technology *x* at node *i* for period *t*
$g^{Heat}_{i,x,t}$	Dispatch of heat-only generation technology *x* in node *i* for period *t*
$y_{i,o,t}$	Dispatch of conversion technology *o* at node *i* for period *t*
$e^{ch}_{i,s,t}$	Charging of storage at node *i*, using technology *s*, for period *t*
$e^{dch}_{i,s,t}$	Discharging of storage at node *i*, using technology *s*, for period *t*
$e^{lv}_{i,s,t}$	Storage level at node *i*, using storage technology *s*, for period *t*
$\varrho_{i,t}$	Electricity curtailment at node *i* in period *t*
$p^{L}_{i,j,t}$	Electricity active power flow from node *i* to node *j* in period *t*
$q^{L}_{i,j,t}$	Electricity reactive power flow from node *i* to node *j* in period *t*
$V_{i,t}$	Voltage magnitude of node *i* in period *t*
$\theta_{i,t}$	Voltage angle of node *i* in period *t*
$\psi_{i,t}$	Reactive power compensation at node *i* in period *t*

Appendix B

Model formulation

The generation and storage capacities are determined by certain lower and upper limits of the different technologies, as described below.

$$\underline{G}_{i,x} \le G_{i,x} \le \overline{G}_{i,x} \tag{B.1}$$

$$\underline{Y}_{i,o} \le Y_{i,o} \le \overline{Y}_{i,o} \tag{B.2}$$

$$\underline{\boldsymbol{E}}_{\boldsymbol{i,s}} \le \boldsymbol{E}_{\boldsymbol{i,s}} \le \overline{\boldsymbol{E}}_{\boldsymbol{i,s}} \tag{B.3}$$

Eqs. B.1-B.3 describe how the model allows for the use of a brownfield approach, taking existing installed capacity as the lower limit for the model to work with (indicated by underlining). In addition, the upper limit of the generation capacity (denoted with overlining) specifies the possibility of additional generation capacity. In the example of wind power generation, the upper limit refers to the maximum allowed capacity of wind power in a specific node i, which can be attributed to wind speed and land availability. Consequently, the operational dispatch of generation technologies is given by Eq. B.4:

$$0 \le \boldsymbol{g}^{\boldsymbol{act}}_{\boldsymbol{i,x,t}} \le \boldsymbol{\rho}_{\boldsymbol{i,x}} \cdot \boldsymbol{G}_{\boldsymbol{i,x}} \tag{B.4}$$

where the dispatch is limited by the installed capacity of generation technology while taking the specific generation profile into consideration. Examples of generation profiles are the wind speed in the case of wind power and the solar irradiance in the case of solar PV, whereas for thermal generation, the typical value would be 1, unless specifically mentioned otherwise.

Equation (B.5) describes that at every hour in every node, there must be a balance between the demand and supply of electricity:

$$\begin{aligned} D^{act}_{i,t} + \sum_{o\in O}\frac{y_{i,o,t}}{\eta_o} + \sum_{s\in S} e^{ch}_{i,s,t} + \sum_{\substack{i\in I\\ i\neq j}} p^{L}_{i,j,t} + \varrho_{i,t} = \\ \sum_{x\in X} g^{act}_{i,x,t} + \sum_{s\in S,} e^{dch}_{i,s,t} + \sum_{\substack{j\in I\\ j\neq i}} p^{L}_{j,i,t} + \chi_{i,t} \end{aligned} \tag{B.5}$$

The left-hand side of the expression provides the demand part of the equation, which consists of the electricity demand, demand due to conversion to heat (power-to-heat) or hydrogen (electrolyser) that depends on the efficiency or coefficient of performance of the respective technologies, charging of electricity storage, electricity flow to other nodes, and curtailment if necessary. The supply part of the equation contains the generation dispatch from electricity generation technologies, discharge from electricity storage, electricity flow to node i, and the possibility of importing/exporting electricity. $\chi_{i,t}$ yields a positive value when it is importing and a negative value when it is exporting.

The nodal balances for the heat and hydrogen sectors are given in Eqs. B.6 and B.7, respectively. Observe that there is no trade between nodes for both the heat and hydrogen sectors, i.e., the demand is met locally in the node.

$$\boldsymbol{D}_{i,t}^{Heat} + \sum_{s \in S} \boldsymbol{e}_{i,s,t}^{ch} = \sum_{g \in G} \boldsymbol{g}_{i,x,t}^{Heat} + \sum_{o \in O} \boldsymbol{y}_{i,o,t} + \sum_{s \in S,} \boldsymbol{e}_{i,s,t}^{dch} \tag{B.6}$$

$$\boldsymbol{D}_{i,t}^{H2} + \sum_{s \in S} \boldsymbol{e}_{i,s,t}^{ch} = \sum_{o \in O} \boldsymbol{y}_{i,o,t} + \sum_{s \in S,} \boldsymbol{e}_{i,s,t}^{dch} \tag{B.7}$$

The expression that governs the storage balance is given in Eq. B.8, where it ensures that the storage level at the next period is dependent upon the storage level, level of charging to the storage, level of discharging from the storage, and losses during the current period.

$$\boldsymbol{e}_{i,s,t+1}^{lv} \le \boldsymbol{e}_{i,s,t}^{lv} + \boldsymbol{e}_{i,s,t}^{ch} - \boldsymbol{e}_{i,s,t}^{dch} - \boldsymbol{e}_{i,s,t}^{loss} \tag{B.8}$$

where the storage losses is dependent on the storage technology losses factor ς_s and the storage level at the previous period, with storage losses factor obtained from [44]. Thus, storage losses is defined as in Eq. B.9

$$\boldsymbol{e}_{i,s,t}^{loss} = \varsigma_s \cdot \boldsymbol{e}_{i,s,t-1}^{lv} \tag{B.9}$$

As the model considers the electricity network infrastructure, each node is able to send or receive electricity that is accounted for in Eq. B.5, given that the node has a power line connected to it. As the regional electricity infrastructure comprises AC power, it consists of active and reactive power components, where the relationship is non-linear. In other energy system modelling studies that have modelled the electricity flow [24,61], a simplistic representation of the electricity network, such as a copper plate model or a simplified DC load flow, has been used, which neglects the reactive power component. However, in the distribution grid, the electricity system is more-resistive compared to a transmission system, which means that the voltage could be more-affected by the electricity network. Thus, reactive power can no longer be neglected, as the voltage limit can be a limiting constraint in the model.

In the RESYST model, a linearised AC power flow approach derived from [62] is used, where this approach is intermediate between a full AC power flow, which captures the non-linearity of the power flow, and a DC power flow, which only considers the reactance of the network. A linearised AC power flow considers both active and reactive power components and applies the following assumptions to the electricity network: (1) the voltage angle differences between nodes are small; and (2) the magnitude of the voltage at each node is within the nominal value.

$$p_{i,j,t}^{L} \approx V_{nom}\left(- G_{i,j}\left(\left|V_{i,t}\right| - \left|V_{j,t}\right|\right) + V_{nom}B_{i,j}\left(\theta_{i,t} - \theta_{j,t}\right)\right) \tag{B.10}$$

$$q_{i,j,t}^{L} \approx V_{nom}\left(B_{i,j}\left(\left|V_{i,t}\right| - \left|V_{j,t}\right|\right) + V_{nom}G_{i,j}\left(\theta_{i,t} - \theta_{j,t}\right)\right) \tag{B.11}$$

Eqs. B.10 and B.11 approximate the active and reactive power flows, respectively. These equations govern the power flow from node *i* to node *j* at time *t*, accounting for the nominal voltage magnitude, network admittance, nodal voltage magnitude, and nodal voltage angle.

The active and reactive power flows between nodes *i* and *j* are limited to the apparent power-line capacity that connects nodes *i* and *j,* and it can be expressed as follows:

$$\left(p_{i,j,t}^{L}\right)^2 + \left(q_{i,j,t}^{L}\right)^2 \le \left(\overline{S}_{i,j}\right)^2 \tag{B.12}$$

Nevertheless, one might notice that Eq. B.12 is non-linear, as it describes a quadratic relationship between the active, reactive, and apparent power components in the AC power flow formulation. Thus, linearisation of Eq. B.12 can be achieved through the following sets of equations, as previously described in [62]:

$$-\kappa \cdot \overline{S}_{i,j} \le p_{i,j,t}^{L} \le \kappa \cdot \overline{S}_{i,j} \tag{B.13}$$

$$-\kappa \cdot \overline{S}_{i,j} \le q_{i,j,t}^{L} \le \kappa \cdot \overline{S}_{i,j} \tag{B.14}$$

$$\tau^p \cdot p_{i,j,t}^{L} + \tau^q \cdot q_{i,j,t}^{L} \le \kappa \cdot \sqrt{2}\overline{S}_{i,j}, \text{ where } \tau^p,\ \tau^q \in \{1, -1\} \tag{B.15}$$

Observe that in Eqs. B.13 and B.14, the values of active and reactive power can either be positive or negative. This indicates that when the value is positive, the power flow direction is from node *i* to node *j*, whereas when the value is negative, the flow direction is the opposite. Eq. B.15 utilises the τ parameter, which limits the maximum active or reactive power delivery, according to its apparent power limit. Together, Eqs. B.13-B.15 describe an operating region for both the active and reactive power forms that respects the non-linearity of the apparent power limits, as shown in Fig. B.1. Notice also that the constant parameter κ in Eqs. B.13-B.15, which constrains the power flow limit further, i.e. the linearised power flow has smaller solution space compared to the non-linear power flow. Here, 0.9 is chosen as the value of κ.

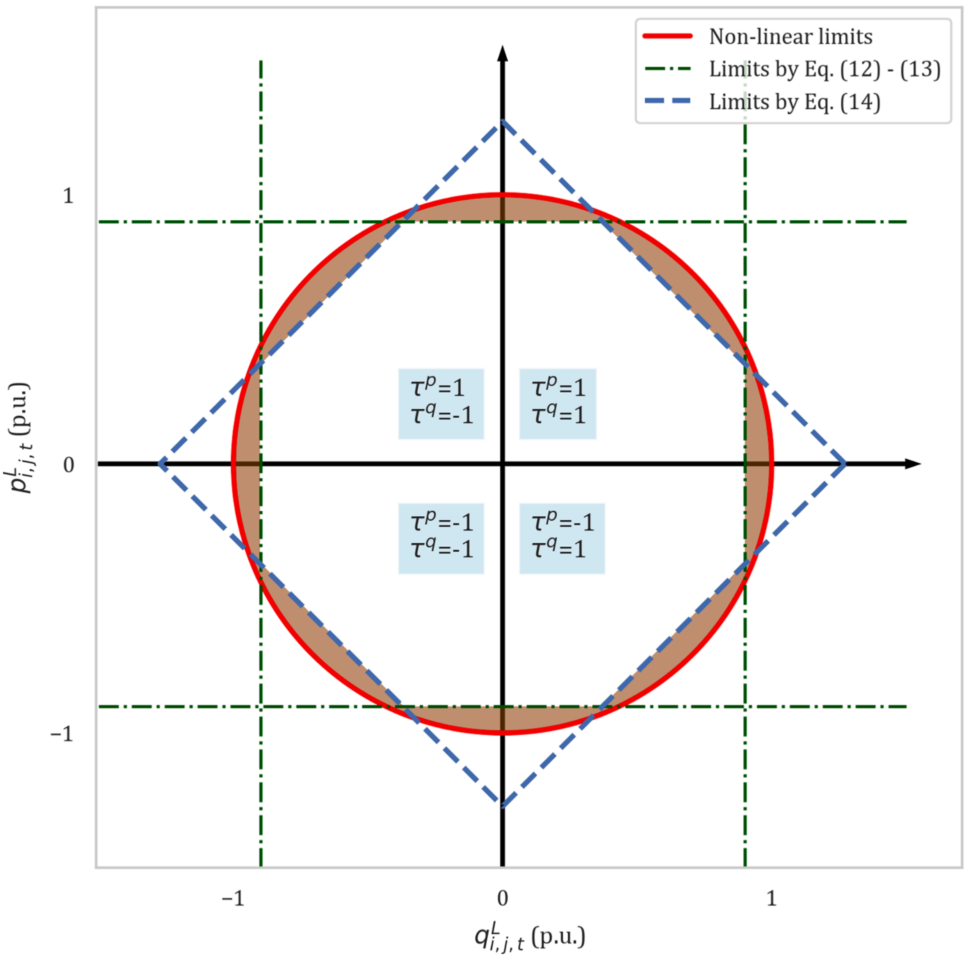


Fig. B.1. Active, reactive, and apparent power limits.

As the model captures the reactive power, it is necessary to define a constraint that depicts the power balance for reactive power in each node at every time, as expressed by:

$$D^{reac}_{i,t} + \sum_{\substack{j\in I \\ j\neq i}} q^L_{i,j,t} = \sum_{x\in X} g^{reac}_{i,x,t} + \sum_{\substack{j\in I \\ j\neq i}} q^L_{j,i,t} + \psi_{i,t} \tag{B.16}$$

Compared to its active counterpart, Eq. B.16 has fewer variables in the equation, where the reactive nodal balance consists of the reactive power demand and the reactive power delivery to other nodes in the demand side, while it takes into consideration reactive power generation by electricity generation technologies, reactive power delivery from other nodes, and nodal reactive power compensation in the supply side. Notice that since electric storage technologies cannot be used to supply reactive power, a reactive power compensation is used instead. The amount of reactive power demand can be computed according to the load power factor ($\cos\varphi$) in Eq. B.17, where the load power factor is assumed to be constant for the entire model period:

$$D^{reac}_{i,t} = \frac{\sqrt{1-PF^2}}{PF} \cdot D^{act}_{i,t} \tag{B.17}$$

The reactive power generation is limited by the amount of active power generation by a specific technology at a specific time, given in Eq. B.18:

$$-\alpha \cdot g^{act}_{i,x,t} \leq g^{reac}_{i,x,t} \leq \beta \cdot g^{act}_{i,x,t} \tag{B.18}$$

The values of α and β are dependent upon the electricity generation technology, which is classified according to whether or not a converter is needed to operate the technology. These values are taken from Swedish TSO Requirements of Generator [63], where it is stated that for converter-based technologies, the values of α and β are 1/3 and 1/3 respectively, whereas for non-converter-based technologies, the corresponding values are 1/6 and 1/3. Moreover, the model has limitations regarding the operating nodal voltage magnitude and angle, as given by:

$$\underline{V}_{nom} \leq |V_{i,t}| \leq \overline{V}_{nom} \tag{B.19}$$

$$-\pi \leq \theta_{i,t} \leq \pi \tag{B.20}$$

Then, the voltage angle difference between nodes is further limited by:

$$\theta_{i,t} - \theta_{j,t} \leq 0.5 \tag{B.21}$$

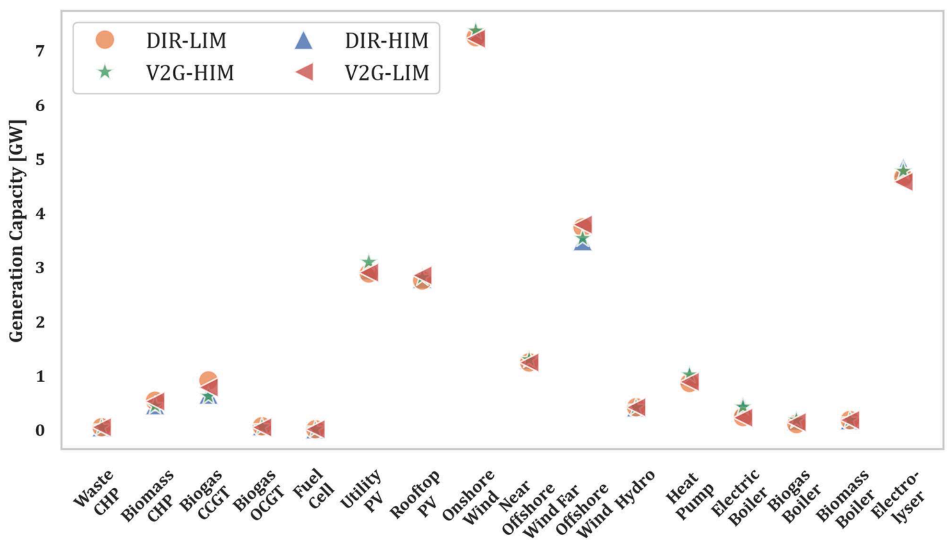
$$\theta_{i,t} - \theta_{j,t} \geq -0.5 \tag{B.22}$$

Eq. B.19 enforces a limit as to how far the voltage magnitude can deviate from the nominal value; here, the limit is set at ±5% of the nominal voltage value. Eqs. B.20-B.22 ensure that the voltage angle differences between nodes are sufficiently small, where in the model, the allowed differences are within 0.5 radians (≈ 30°). These sets of equations related to voltage are required so that the model abides with the assumptions mentioned previously, which allows the linearised AC power flow approach to be valid.

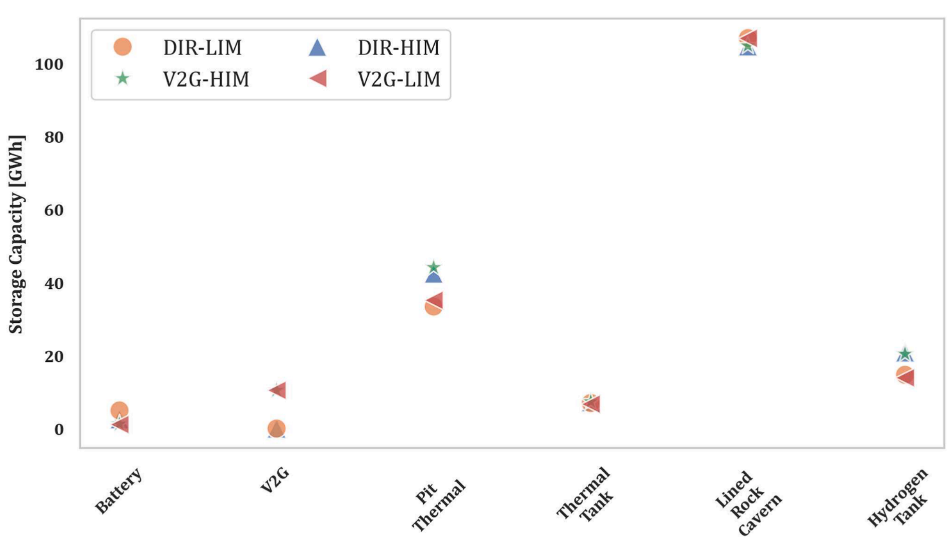
Appendix C

Deployment of technologies in the region

The total deployments of generation and storage technologies considered in RESYST across all study cases for the VGR are shown in Fig. C.1, where the top panel presents the deployment of generation technologies, whilst the deployment of storage technologies is given in the bottom panel. The figure shows the robustness of the model, where the deployment of technologies is not heavily dependent upon certain model parameters.



(a)



(b)

Fig. C.1. Total investments in VGR for generation (a) and storage (b) technologies.

Fig. C.2 presents the connection points of the deployment of near and far off-shore wind power in the DIR-LIM and V2G-HIM cases. It is evident that off-shore wind technologies are deployed mainly in the western coastal zones of the region which also host high electricity demand

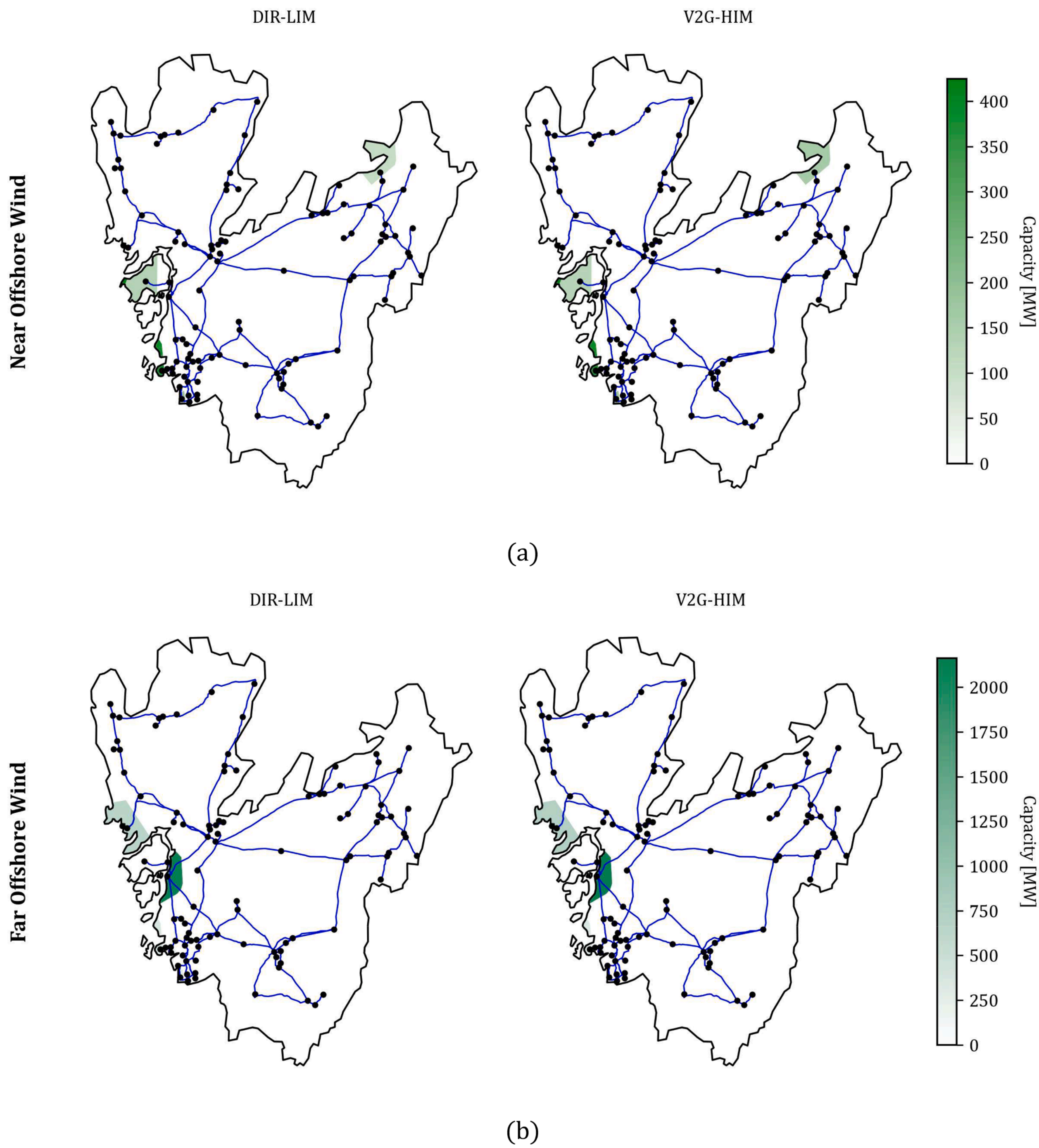


Fig. C.2. Deployment of near off-shore wind (a) and far off-shore wind (b) generation plants.

Flexible heat production in the region

Fig. C.3 depicts the modelling results for the heat sector, focusing of the LID1 node, which is a node with a high heat demand and strong deployment of PTES. PTES charges during periods of low electricity prices (as in Hour 3,200) and discharging during periods of high electricity prices, exemplified by Hours 800 and 1,600. An exception occurs at Hour 7,000, when PTES is charged although the electricity price is relatively high at 130 €/MWh. Based on the heat pump and PTES operational patterns, heat pumps are not utilised to charge PTES but rather act as a technology to meet the base heat demand. There is also a distinct operational pattern where CHP operates when the heat pump does not, emphasising that these technologies are interchangeable in terms of serving the heat demand.

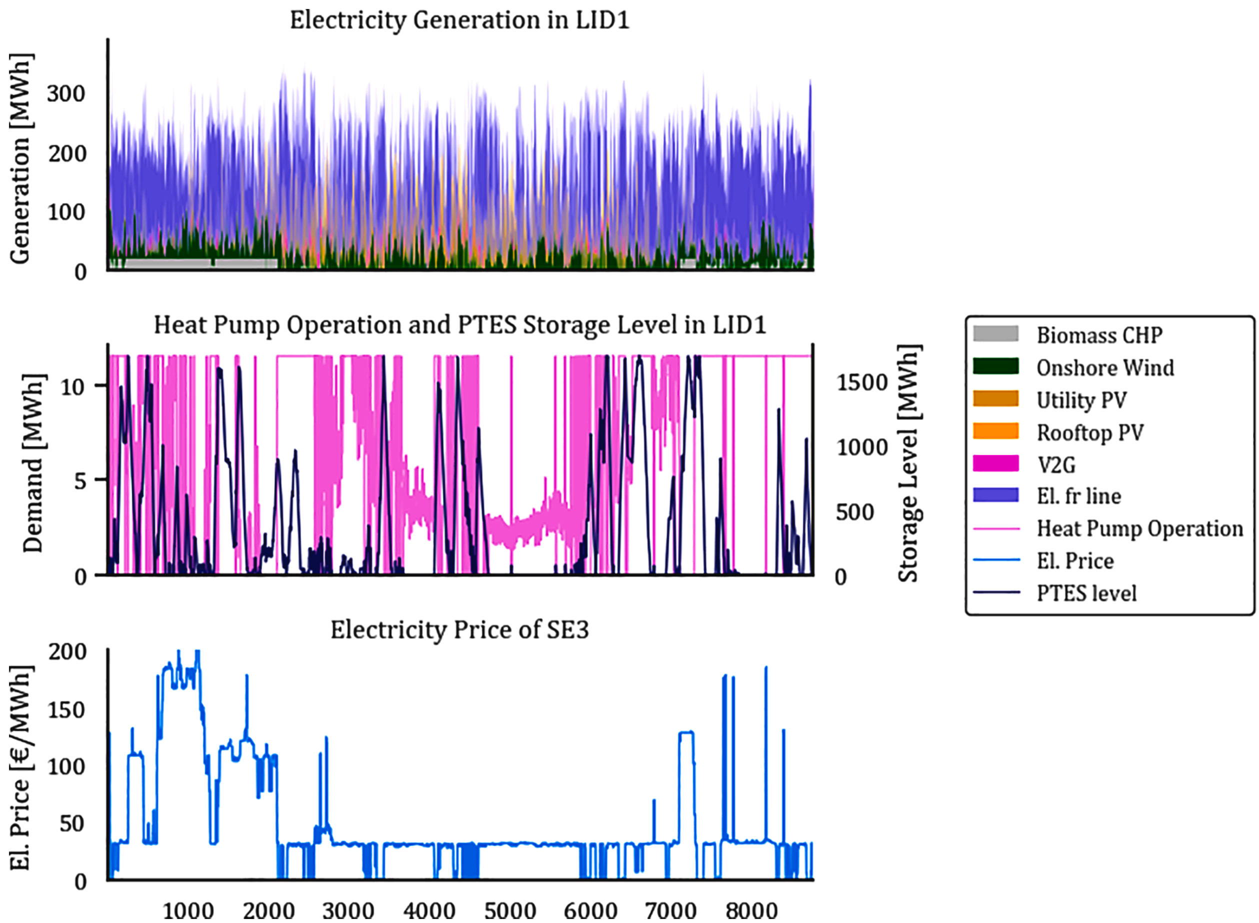


Fig. C.3. Operational dispatch and electricity price in LID1 for 1 year.

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