Managing capacity deficiencies in distribution grids using local resources

A techno-economic case study of Gothenburg

Master's thesis in Sustainable Energy Systems

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Abstract

Electricity demand in Gothenburg is projected to increase at a rate where current import capacity and local production are insufficient to meet the demand given current market structures. Import capacity extensions are currently being built but is insufficient to meet the projected increase in time. This thesis aimed to investigate what combination of local resources could cost-effectively meet the projected demand using mixed integer linear programming models. Two models were developed, one used for different cases of possible import capacity which covered a time-horizon from 2025 to 2040. The other one was developed to investigate the optimal import capacity by 2040, and different resource availability were investigated for both models.
Results show that utilizing local flexible and plannable resources in an effective way, has significant potential in solving congestion issues.

Keywords: Mixed integer linear optimization, Congestion, Distribution grid

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Nomenclature

Below is the nomenclature of indices, sets, parameters, and variables that have been used throughout this thesis.

Sets

C	Set of capacity measures, {Rya, Flexibility, GT, BESS GENAB, BESS OA, Residential Batteries, V2G}.
M	Subset of non-storage capacity measures {Rya, GT, Flexibility}.
N	Subset of capacity measures with a thermal start-up cost {Rya, GT}.
P	Set of technologies that can be invested in {BGS (BESS GENAB Storage capacity), BGP (BESS GENAB Power capacity), GT (Gas turbine)}.
L	Set of local combined heat and power plants, {Sävenäs KVV, Rya KVV, Renova KVV}.
T	Set of hourly time steps in time horizon, {0,..., N}.
T_H	Subset of hours around and including deficiency hours $T_H \subset T$.
T_F	Subset of hours in 2040, $T_F \subset T$.
D	Set of days in time horizon.
H_d	Subset of hours in day d. For each $d \in D$, $\quad H_d \subseteq T$.
Q_H	Set of quarters in the deficiency periods in the time horizon.
Q_F	Set of quarters in 2040.
F	Set of flex resources, {Heat-pump for small houses, Retail refrigerators and freezers, Real estate, Premises & Services}.
S	Set of energy storage technologies, {BESS OA, V2G, Residential Batteries}.
SS	Subset of stationary storages $SS \subset S$, {BESS OA, Residential Batteries}.
V	Set of intermittent generators connected to the local grid, {Gårdsten, Solivarium, Nya Solevi}.

I	Set representing import capacity investment decision, {1 (850 to 1000), 2 (1000 to 1250)}.

Parameters

D_t^{el}	Power demand at timestep t [MW].
cap_t^{trans}	Import capacity at timestep t [MW].
t_w	Time window before and after capacity deficiency hours [h].
$F_{f,t}^{cap}$	Capacity of flex resource f at timestep t [MW].
F_f^{end}	Flex resource endurance of flex resource f [h].
F_f^{rec}	Recovery period of flex resource f [h].
$g_{i,t}^V$	Power production from intermittent energy generator i at timestep t [MW].
$g_{i,t}^L$	Power production from CHP i at timestep t [MW].
$V2G_t^{available}$	Amount of energy available for V2G at timestep t [MWh].
$CH_{s,t}^{cap}$	Charge capacity of energy storage technology s at timestep t [MW].
$DCH_{s,t}^{cap}$	Discharge capacity of energy storage technology s at timestep t [MW].
$soc_{s,t}^{cap}$	Storage capacity of energy storage technology s at timestep t [MWh].
Ex_c^{Op}	Cost of capacity supplying technology c [MSEK/MWh].
Ex_p^{Om}	Fixed operation & maintenance of resource p [MSEK/quarter].
Ex_{th}^{Inv}	Capital costs of technology th [MSEK/MW].
Ex_{Rya}^{res}	Reservation cost of reservable resource Rya [MSEK/MW,day. MSEK/MW,quarter].
Ex_n^{start}	Start-up cost of generator n [MSEK/MW].
τ_t	Time value at timestep t [-].
$Ex^{trans-subscription}$	Annual cost of import capacity [MSEK/MW].
$Ex_i^{trans-inv}$	Investment cost of import capacity extension i [MSEK/MW].
$Ex^{trans-Op}$	Running cost of import [MSEK/MWh].
$RyaGT^{cap}$	Rya gas turbine capacity at timestep t [MW].
$RyaST_t^{cap}$	Rya steam turbine capacity at timestep t [MW].
MLL_{GT}	Minimum load level of Rya gas turbines.
MLL_{ST}	Minimum load level of Rya steam turbine.
lim_i^{trans}	Capacity increase limit from investment decision i [MW].

Variables

$g_{c,t}$	Power supplied by capacity measure c at hour t.
g_t^{trans}	Power supplied by import at timestep t [MW].
$\Delta g_{n,t}$	Increase in generation of generator n at timestep t [MW].
$R_{g,t}^{Activate}$	Binary variable to monitor when turbine g go active.
$R_{g,t}^{Active}$	Binary variable to monitor when turbine g is active.
$F_{f,t}^{\text{Activate}} \in \{0,1\}$	Binary variable to monitor activations of demand-side flex resource f at hour t [-].
$F_{f,t}^{Active} \in \{0,1\}$	Binary variable representing if a demand-side flex resource f is active at hour t [-].
$soc_{s,t}$	State of charge of storage s at timestep t [MWh].
$\Delta soc_{s,t}$	Change of energy in storage s at hour t [MWh].
$C_{r,d}^{res}$	Reserved capacity of resource r at day d [MW].
BEC_t^E	Energy taken from the Battery electric car-fleet at timestep t [MWh].
$Cap_{p,t}$	Installed capacity of technology p at timestep t [MW, MWh].
$\Delta Cap_{p,t}$	Change of installed capacity of technology p at timestep t [MW, MWh].
Inv_i^{trans}	Binary variable representing the decision to increase import capacity from: 1, 850 to 1000 MW. 2, from 1000 to 1250 MW.
Δcap_i^{trans}	Transmission capacity increase from investment decision i.
Ex^{tot}	Total cost of new resources [MSEK].

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1
Introduction

As more industries switch their source of energy from fossil fuels to electricity and new actors within energy-intensive industries such as battery manufacturers are getting established, the need for electricity and consequently grid-capacity will increase. Gothenburg is one city home to multiple industries planning to undertake this energy transition and there are projections for how the power demand will increase until 2040. According to these power demand projections along with the estimated timeline for the transmission capacity expansion to the region of Västra Götaland as well as to Gothenburg, there is a risk that there will not be enough capacity to supply the demand in just a matter of a few years [1]. Consequently, the distribution system operator Göteborg Energi is interested in exploring how capacity can be supplied locally and what combination of resources can accomplish this cost-optimally, and in addition, if using local resources can be more cost-optimal compared to increasing import capacity from the regional grid.

1.1 Aim & Research questions

The aim of this thesis was to conduct a techno-economic analysis using optimization models to investigate the potential of using local capacity resources to resolve capacity deficiencies during high load hours, and in addition, compare the associated costs with import capacity extensions.
The research questions related to the aim are:

- How does the method of compensating capacity impact the cost-optimal solution?
- What combination of capacity resources can supply the power demand in a cost-effective way? And under what circumstances?
- How can local renewable production decrease capacity costs?
- Can local capacity solutions compete with investments in import capacity?

1.2 Background

Göteborg Energi AB is an energy company located in Gothenburg, which sells and distributes energy in the form of electricity, district heating and gas. This thesis is made in cooperation with its subsidiary Göteborg Energi Nät AB (GENAB) which are responsible for the distribution of electricity in the local grid. Currently 10 % of the annual electricity demand in Gothenburg is satisfied by local resources [1].

These resources mainly consists of Combined Heat and Power plants (CHPs), solar power and wind power. The local CHPs are:

- Renova KVV: Renova burns waste and have historically produced electricity year round as a local base load.
- Rya KVV: A CCGT-plant which has historically been run on natural gas with an electric capacity of 255 MW. Göteborg Energi is currently constructing a new bio-fuel boiler, which will be connected to the steam-turbine and is expected to produce about 30 MW as a base load in the local system during the winter months [2].
- Sävenäs KVV: A smaller plant using bio-fuels [3]. The plant mainly produces heat but can supply electricity after demand.

Although the electricity production of these plants in large extent are dependent on a heat demand, the heat demand in Sweden typically coincide with the hours with the highest demand for electricity as power demand in Sweden is strongly dependent on ambient temperature [4]. The remaining 90 % of the yearly electricity demand is satisfied by import from the regional grid. The regional grid is operated by two different Distribution System Operators (DSO's); Ellevio and Vattenfall. The latter provides a larger share of the electricity demand. GENAB currently have a total yearly subscription of 850 MW from these providers which is on the level of what the DSO's are able to deliver at the moment. There are currently ongoing projects involving Vattenfall to increase the capacity by building two new 130kV-lines and reinvest in stations [5], which are expected to be complete by 2031. The investments leads to a technical increase of capacity by up to 400 MW, but there are bottle necks in the transmission grid which limits the short term increase of capacity to 150 MW. There are ongoing investigations to increase the capacity between the transmission grid to the regional grid to enable an additional 250 MW, but this is expected to be achieved by 2036 at the earliest [1]. Figure 1.1 shows the projected peak load for each year leading up to 2040 along with the estimated import capacity increases, implying that the demand for power is exceeding the rate that import capacity is currently being built. This means that action has to be taken, and that alternative sources of capacity are required, in order to meet the future demand and enable the electrification of Gothenburg.

There are uncertainties in the methods of mitigating capacity issues, along with allocating costs on both a regional and national level. Svenska kraftnät (SvK) have recently proposed two approaches to handle capacity deficiency while grid extensions are under construction. The first is conditional agreements with new connecting customers [6], meaning that new connections can be made but the power provided can be decreased if the operating situation demands it. The second is signing short term contracts with capacity providers that is obliged to provide capacity when needed. The cost of this should be distributed among the new connecting customers. A capacity provider could however be useful on other markets as well, raising the question of how the cost should be distributed.

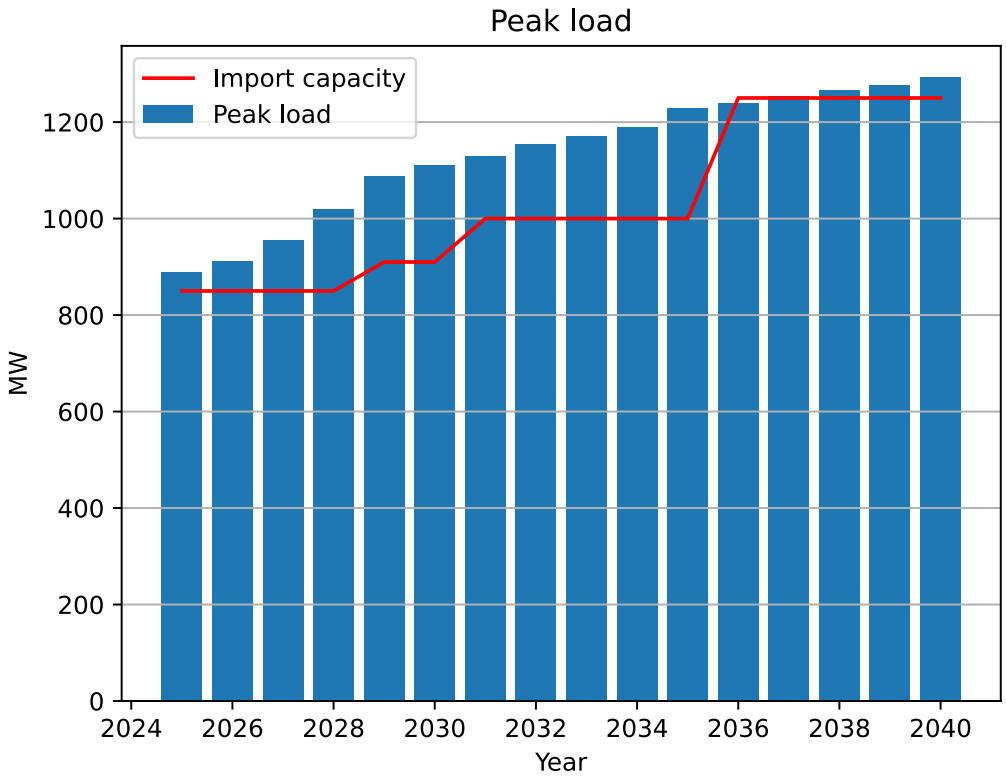


Figure 1.1: Projected peak load per year for 2025-2040.

1.3 Resources in the local electricity system

The resources considered in this analysis include existing power producing facilities, intermittent energy sources and storage solutions, along with projections of their future development. Additionally, this thesis examines new investments that can mitigate capacity problems, specifically battery energy storage systems (BESS) and gas turbines.

As discussed, the majority of the power production within Gothenburg comes from the three major combined heat and power plants. However, the future of CHP's in Sweden is uncertain with increased demand of biomass in Europe driving the fuel costs up for the plants that run on bio-fuels [7]. In addition, the local heating demand is to a large degree covered by residual heat from local industries, heat pumps and energy recovery from waste [8]. Rya KVV have a capacity of 255 MW in form of combined cycle gas turbines consisting of three 40 MW gas turbines and a steam turbine rated at 135 MW. Operation of this plant has decreased over the last years due to low electricity prices and increasing fuel costs. At present it's being used for counter-trade, under contract with SvK until January 2026 [9].

Regarding local intermittent production, Gothenburg is currently among the cities in Sweden with the highest installed solar capacity with an installed capacity of 134

MW at 2023 [10]. There is also a wind turbine with a capacity of 2 MW located at Gårdsten [11]. There are investigations regarding connecting a new offshore wind park with a total capacity of 1000 MW directly to the local grid, the impact of this on capacity costs will be investigated in this project.

In addition to production facilities, are storage solutions also considered in this project. The first storage solution is small-scale residential batteries with an assumed capacity of 10 kW / 10 kWh, the aggregated capacity of these within Gothenburg is estimated to be around 30 MW today based on GENAB's estimates. The second type of batteries considered are large scale Battery Energy Storage Systems (BESS) which also have been established locally and is expected to reach 100 MW / 100 MWh capacity by 2026 [12]. BESS are to the contrary of residential batteries often owned by companies rather than private persons. The last storage technology considered is Vehicle to Grid (V2G) which was used for the first time in April 2025 to provide capacity on the local flexibility market [13]. However, the technology is still developing. This project investigates the potential of energy storage as a local capacity resource and to what cost they can be assumed to be willing to participate. Additionally, demand-side flexibility (DSF) as a compensated flexible resources will also be considered. The amount of potential DSF available throughout the time horizon used for the model is based on estimates provided by GENAB.

1.4 Limitations

This study uses mixed-integer linear optimization models that are developed using the modeling framework Pyomo [14] and the models were solved using Gurobi, developed and distributed by Gurobi Optimization [15]. Due to the amount of timesteps in the time horizon as well as the number of variables of interest, a number of simplifications had to be made. Combined heat and power plants are assumed to be following the heating demand which is seasonal and based on historical data and is therefore treated as parameters, intermittent generation of solar and wind are based on a yearly profile which is extended to match the full time horizon, thus yearly variations are not considered. Resolving the capacity deficiencies and investigating the optimal import capacity had to be treated separately due to the size of the problem, so two models were developed, one where import capacity is treated as a parameter and only considers the hours surrounding and including the hours when there are capacity deficiencies for the full time horizon.
In the other model import capacity was treated as a decision variable but the time period investigated is one year and the year chosen were 2040 due to it being the year with the highest estimated loads in the time horizon.

2
Method

The general methodology of this project follows a structured sequence of steps and can be seen in Figure 2.1. Since the purpose of the project was to conduct a techno-economic analysis to investigate the benefits of local resources in the electricity system in Gothenburg, the first step was to define the current system and estimate how it will change in the future. This included defining what could be considered as controllable resources, called variables, and what are parameters. Next, the costs of utilizing different resources were identified. To investigate different potential future developments and views of reimbursement of capacity, different cases of interest were developed. Simultaneously the MILP-models were developed in order to find the cost-optimal way to address the capacity deficiencies, determining volumes of new and existing resources required, and the associated total costs.

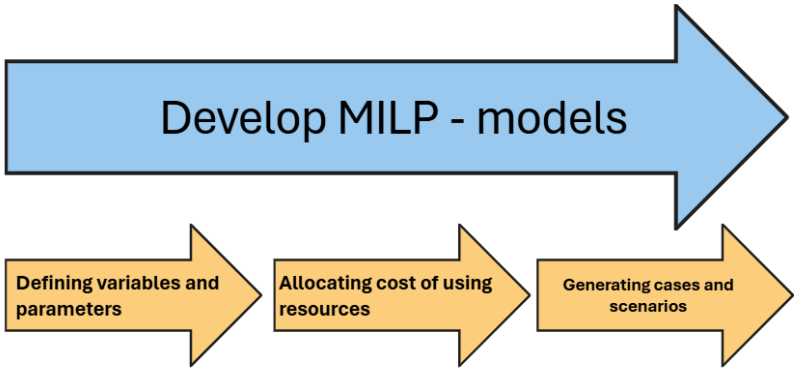


Figure 2.1: Flow diagram of the general methodology.

The prognosis of the electricity demand was supplied by GENAB. The prognosis includes the estimated hourly demand of electricity from 2025 to 2040 in the city of Gothenburg. The data is based on the current need, industrial electrification, and growing electricity demand from transport and urban development. The prognostics do not include any flexibility except for a small share of smart vehicle charging at the end of the time horizon. It also does not include any assumptions regarding an increasing self-sufficiency from solar panels and batteries.

Figure 2.2 presents a schematic overview of the model used in this project, of the input parameters, dispatch- and investment options.
The following sections include the data and assumptions going into each local resource featured in the model.

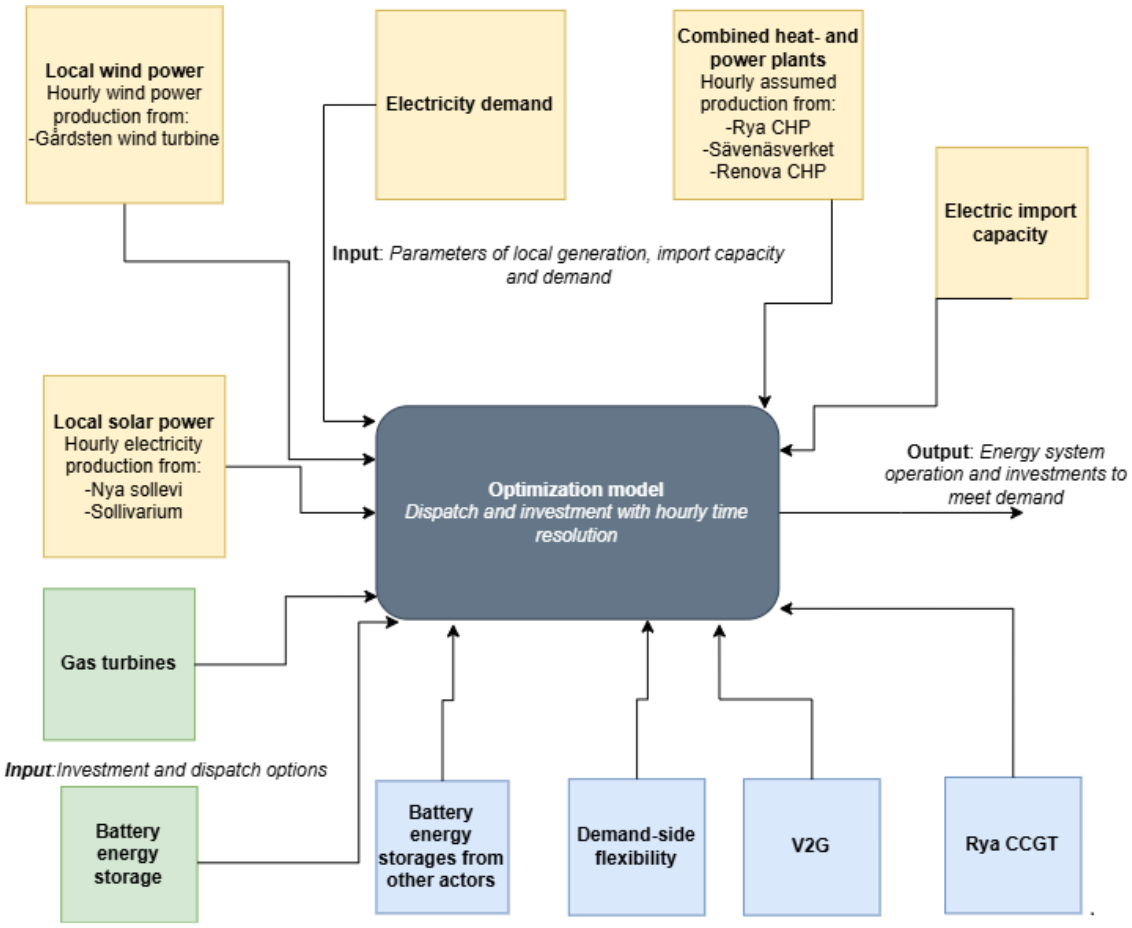


Figure 2.2: Overview of the mixed-integer optimization model developed and used. Yellow boxes indicate parameters, blue boxes indicate dispatch options and green indicates investment options that can be dispatched.

2.1 Dispatch & Investment variables

The dispatch variables are the resources that the model use to supply power when there is a capacity deficit. They are considered as controllable and available to use given that they are compensated. The dispatch variables consist of energy storages, demand-side flexibility, utilizing the capacity of Rya CCGT. The model can also invest in new large scale batteries (BESS) and gas turbines which then also becomes dispatchable.

None of the current dispatch variables are owned or operated by GENAB but are assumed to be available if the owners are compensated at the right price. Estimating at what cost a battery owner is willing to participate on a flexibility market is complicated and depends on things such as electricity prices, other balancing markets, operational costs and depth of discharge. The cost that was chosen for the model is the battery's Levelized Cost of Storage (LCOS). The LCOS includes all the operational costs (OPEX) and capital costs (CAPEX) per unit of stored energy and guarantees that all costs for delivering energy are covered along with a return

of investment. More about calculating the LCOS for the different storage resources are described in their corresponding subsection. No assumptions were made regarding battery owners acting on other markets in hours of capacity deficiency that can passively either relieve or worsen the capacity deficiency.
The method of allocating costs towards plannable production was made differently. Producing power from gas has become increasingly expensive due to increasing gas prices and low electricity prices resulting in less hours to recover costs annually. This has resulted in fewer operation hours for Rya CCGT. Because of this it was assumed that in order to use Rya, the fixed and capital costs be must be covered to a larger degree.
For investments in new resources all investment and fixed costs were allocated towards GENAB. It was also assumed that if a resource is providing capacity, that they are not simultaneously compensated on another market.
The following subsections describes how each variable resource is used in the model.

2.1.1 BESS

BESS or utility-scale batteries are large stationary batteries. They can be designed and used for different purposes including balancing, spot price arbitrage or as a capacity resource. The installed capacity of BESS available that is facilitated by other actors and are used for the models is based on the data that is presented in the report by Göteborg Energi [12, p. 16]. Even though the investment cost of large-scale BESS are still expected to decrease [16] there are no clear projections of how the installed capacity of these will develop within Gothenburg, therefore it was assumed that the level of installed capacity by 2026 remains constant throughout the time horizon. To differentiate between BESS that is invested in by the model and BESS that is facilitated by other actors, BESS facilitated by other actors are denoted as BESS OA, and BESS invested in by the model is denoted BESS GENAB. The storage- and power capacities throughout the time horzion for BESS OA used in the model, are presented in Table 2.1.

Table 2.1: Storage and power capacity parameters used for the BESS facilitated by other actors.

Year	2025	2026-2040
Capacity [MW/MWh]	60/60	100/100

The cost for capacity from BESS OA was calculated from the formula for Levelized Cost of Storage (LCOS) as:

$$Ex^{Op}_{BESS\ OA} = \frac{Capex + Fixed\ O\&M}{n_{cycles} * \eta_{RT}} + \frac{Opex}{\eta_{RT}} \tag{2.1}$$

Where $Capex$ is the capital cost of the BESS OA calculated as $Capex = LT_{BESS\ OA} * CRF * Ex^{Inv}_{BESS\ OA}$ where $Ex^{Inv}_{BESS\ OA}$ and $LT_{BESS\ OA}$ is the investment cost and economic lifetime of the investment respectively. $Opex$ is assumed to be the average cost of electricity during high load hours. The capital recovery factor CRF is calculated as:

$$CRF = \frac{r \cdot (1+r)^{LT_{BESS\ OA}}}{(1+r)^{LT_{BESS\ OA}} - 1} \tag{2.2}$$

The economic parameters for BESS OA are presented in Table 2.2. A discount rate of 7% was assumed based on an average rate of return on the stock market. The state of health and the end of life of the BESS is highly dependent on the depth of discharge [17], this wasn't modeled and a lifetime of 7000 cycles (n_{cycles}) was assumed as an approximation of moderate depth of discharge throughout the BESS lifetime.

Table 2.2: Parameters used to calculate cost of BESS OA, along with the resulting cost.

Parameter	**Value**
OPEX [SEK/kWh]	0.7
Efficiency (η) [–]	0.91[1]
Number of cycles (n_{cycles}) [–]	7000
Investment cost ($Ex^{\text{Inv}}_{\text{BESS OA}}$) [SEK/kW]	5753[2]
Fixed O&M [SEK/kW, year]	211.4[2]
Economic lifetime ($LT_{\text{BESS OA}}$) [years]	15[2]
Discount rate [%]	7
LCOS [SEK/MWh]	2755

The economic parameters for new investments of BESS GENAB are almost the same as for current BESS OA. The differences are that the investment cost are divided into a storage capacity cost and a power capacity costs which are presented in Table 2.3 along with the other economical parameters. Since the whole investment and fixed cost already is allocated towards GENAB the LCOS will not be used for activating these batteries, the activation cost will only be based on the OPEX.

Table 2.3: Assumed operation and investment cost of BESS GENAB, investment costs are derived from [16].

OPEX [SEK/kWh]	0.7
Efficiency (η) [–]	0.91[1]
Output capacity [SEK/kW]	3035
Storage capacity [SEK{kWh]	2720
Fixed O&M [SEK/kW, year]	211.4[2]

2.1.2 Residential batteries

Residential batteries are smaller in scale compared to BESS and is typically owned by individuals rather than companies. There is currently a capacity of about 30 MW of residential batteries distributed throughout the city of Gothenburg according to

[1]Derived from [18].
[2]Derived from [16].

GENAB's data. The batteries are assumed to be 10 kW / 10 kWh. The batteries are today used mainly on balancing markets by aggregators and in combination with solar panels to more efficiently use the produced energy for self-sufficiency. The interest for residential batteries have increased a lot in recent years [19] and in this project it is assumed that the capacity will continue to increase in the same rate as for solar panels. The yearly assumed capacity of residential batteries can be found in Appendix A.1. The cost for capacity from residential batteries was calculated in the same way as for BESS OA in equation 2.1. OPEX, efficiency, discount rate, Fixed O&M and economic life time was assumed to be the same as for BESS seen in Table 2.2. The only difference was investment cost and number of cycles. The cost of residential batteries in Sweden is up to 14000 SEK / kWh including inverters and installment [20]. However, if the battery is paired with solar energy can a tax deduction of 48.5 % of the cost of materials and installment be applied, but to a maximum of 50 000 SEK [21]. Based on this, the cost of residential batteries was approximated to 10 000 SEK / kWh. The amount of cycles for a 10 kWh Lithium-ion or Lithium-iron-phosphate which are the most common residential batteries were chosen to be 5000 [22]. The resulting LCOS for residential batteries is 5085 SEK / MWh.

2.1.3 Vehicle to grid

Vehicle to grid is an emerging technology that has potential as a flexible resource for the local electricity system and V2G participated for the first time in the local flexibility market in march this year (2025) [23]. Swedish Energy Markets Inspectorate estimates that by 2030 10% of Battery Electric Cars (BEC's) will have V2G-functionality [24]. This share is projected to increase to 30% by 2035 and 50% by 2040. For the model, linear increase of V2G-functional BEC's are assumed and applied on new registrations from 2025 until 2040. Historical data indicates that the annual amount of newly registered BEC in Gothenburg are about 4000 cars per year [25], which is the assumed increase of BEC's in the model throughout the time horizon. The average storage capacity of a battery in a electric car is assumed to be 60 kWh. The capacity of the battery that is available for V2G is assumed to be 11 kWh/h [24]. The yearly available capacity from V2G can be found in Appendix A.2. Data provided by researchers at Chalmers was used to estimate the potential hourly capacity available from V2G. The dataset included the percentage of electric vehicles that is connected to the grid every hour as well as the hourly share of charging demand of the car fleet, for a full year. It is assumed that a BEC's drives about 13000 km per year and uses 0.2 kWh / km which gives a yearly energy need of $13000 * 0.2 = 2600$ kWh / year / car. The hourly charging demand includes the distributed yearly energy demand. Table 2.4 list all the mentioned parameters.

Table 2.4: V2G-Related Parameters for Battery Electric Car Charging.

Description	Parameter
Amount of BEC each hour	$n_{\text{cars,t}}$
Share of BEC with V2G at hour t [%]	$P_{\text{V2G,t}}$
V2G capacity per car [kW]	$V2G_{cap}$
Share of cars connected to grid at hour t [%]	$V2G_{\text{connected},t}$
Charging demand at hour t [kWh/car]	$Ch_{\text{demand},t}$

The available capacity from V2G each hour was calculated as:

$$V2G_t^{available} = P_{V2G,t} \cdot ncars_t \cdot (V2G_{cap} \cdot V2Gconnected_t - Chdemand_t) \quad (2.3)$$

The Levelized Cost of Storage was used to estimate the cost of using V2G. The same OPEX, efficiency, economic lifetime and discount rate were used for BESS OA and as well as for residential batteries, found in Table 2.2. The investment cost for the batteries of a BEC was set to 1242 SEK/kWh [26]. The investment cost is excluding the cost for bidirectional chargers that is needed to use V2G. This is due to unsure cost developments of bidirectional chargers compared to current chargers, and difficulties of deriving the cost towards the usage of the car battery. The number of life cycles was estimated to 3000 [27]. Based on this, the LCOS for V2G was calculated to be 1518 SEK / MWh.

2.1.4 Demand-side flexibility

The term flexibility in the context of power system is described by Swedish Energy Markets Inspectorate as the system's ability to handle changes to production, demand and power capacity in the grid [28]. Demand-side flexibility refer to changes to the demand in order to balance the system. There are a few different potential sources of demand side flexibility; Commercial freezers, heat pumps and buildings HVAC. The sections and their corresponding capacity used for the model are based on estimates of potential flexibility of these segments performed by Göteborg Energi. Their maximum endurance time and restoration time is based on the report by DNV GL Energy [29] and is presented in Table 2.5. The endurance time is the maximum duration a resource can be active as a flexible resource before it must deactivate and the restoration time is the duration a resource needs to recover before it can be activated again. There is no direct running cost associated with the flexibility of these segments as presented in [29, Tab. 37], however participating actors must recover the capital cost taken to be flexible which is dependent on the amount of hours they are expected to be called upon on an annual basis, and the capital cost to be flexible also differs between the segments. Therefore in order to simplify, a cost of demand-side flexibility of 2000 SEK/MWh/h was assumed. The capacity of demand-side flexibility resources are between 27-30 MW and are presented in more detail in Figure A.1 in the appendix.

Table 2.5: Recovery- and endurance time of demand-side flexibility sources.

Flex resource	Recovery time [hours]	Endurance time [hours]
Heat-pump for small houses	2	1
Retail refrigerators and freezers	2	1
Real estate	2	1
Premises & Services	2	1

2.1.5 Gas turbines

The modeled local gas turbines includes both Rya CCGT-plant and new investments done by the model. Since Rya is facilitated by another actor, two different reimbursement cases were considered for capacity from Rya. The first case is based on a daily reservation, where Rya, beside their running costs, are reimbursed capital costs and fixed operational costs of the facility proportional to the maximum capacity required for the day in question.

The second reimbursement model covers the same costs, but on a longer time frame. Similar to how Svenska kraftnät have procured Rya CCGT on a quarter to year basis for counter-trade [30] the plant will be reserved as a capacity resource in the same time frame. The reservation level is based on the highest capacity required from the plant during this period. This type of compensation is under the assumption that the capacity reserved can not be used for other markets, but eventual excess capacity of the plant can be used for other purposes.

The running cost of Rya and new gas turbines are based on an assumed fuel cost of 800 SEK/MWh_{gas} for biogas, and an assumed electric efficiency of 0.42 and 0.35 respectively.

The start-up costs of the gas turbines are approximated as the mean cost obtained from the best and worst case start-up cost presented in the report by Prina et al [31, Table. 3], assuming cold start costs for Rya and hot start costs for new gas turbines.

The costs of using Rya and new gas turbines are presented in Tables 2.6 and 2.7. The capital cost (CAPEX) of Rya were allocated from the presented investment cost for CCGT's from [32] and the economic lifetime and fixed operational cost were approximated as gas turbines from [16]. A discount rate of 10% was assumed based on the amount of uncertainty in the investment. Using equation 2.2 to calculate the CRF of gas turbines, the yearly capital costs can be calculated as $CRF_{Rya} \cdot CAPEX_{Rya}\ [SEK/MW] = 1\ 090\ 760\ [SEK/MW_{year}]$. The fixed operational and management costs: $Fixed\ O\&M_{Rya} = 143\ 833\ [SEK/MW_{year}]$. The reservation cost is the summation of the capital costs and the fixed operation costs and then adjusted for either a daily or quarterly time period.

Table 2.6: Costs of utilizing Rya.

	Rya
Running cost [SEK/MWh]	1900
Start-up costs [SEK/MW]	2350
Reservation cost per day [SEK/MW,day]	3380
Reservation cost per quarter [SEK/MW,quarter]	308 425

Table 2.7: Costs of new gas turbines.

	GTs
Running cost [SEK/MWh]	2300
Investment cost [SEK/kW]	8415
Fixed O&M [SEK/MW,year]	143 833
Start-up costs [SEK/MW]	1500

Currently, Rya has between 195-255 MW dispatchable electric capacity. The available capacity varies due to that a part of the capacity is used as base production during the colder part of the year, in 2025 this base-production has been expressed to be 60 MW but will be reduced to 30 MW from 2026 onward due to the installation of a new bio-fuel boiler [2]. In the model it is assumed that an amount of the capacity will be producing during high load hours, and that the remaining capacity is available for dispatch. In 2025 between October and April, 195 MW dispatchable capacity are available and 255 from May to September. It is assumed from 2026 onward it will be 225 MW from October-April and 255 MW from May-September.

2.2 Parameters

The parameters are as mentioned used as input to the models, meaning that they are not controllable. In the following subsections are the resources described in more detail and how they are assumed to develop during the time horizon.

2.2.1 Transmission

Transmission is handled as a parameter in the base model. However, in a special case only looking at the year 2040 the import capacity will be treated as a variable. Currently the maximum import capacity is 850 MW. There are plans on adjusting current apparatus and installing new lines to increase the capacity from 850 MW to 1250 MW. There are bottle-necks further up in the grid which limits the import capacity to 1000 MW. It is estimated that by 2036 this bottle-neck will be resolved, resulting in a maximum import capacity of 1250 MW. In the full time horizon model there are no cost associated with the import capacity, however when comparing different import capacities the cost of each level will be included. The capital recovery factor of investments in import capacity was calculated as 2.2 with an discount rate of 5% [33] and an economic lifetime of 50 years [34]. The fixed cost and the

running cost of importing power is based on the subscription and transmission fee for L1-customers in southern Sweden from Vattenfall [35]. The investment cost of increasing import capacity is based on internal estimates from GENAB and Svenska Kraftnäts grid development plan [36]. The cost was simplified to 13.8 MSEK / MW to increase grid capacity from 850 MW to 1000 MW including costs for the north-south package and regional investments and 10 MSEK / MW between 1000 MW up to 1250 MW only including Svenska Kraftnäts grid development plan. The investment costs of grid was equated the cost of local capacity to compare the cost of capacity.

2.2.2 Solar power

In 2023 the municipality of Gothenburg had a total installed solar power capacity of 134 MW. An estimate of the increase in solar panel installations was performed using linear extrapolations using data from 2019 through 2023 [10], and is shown in Figure 2.3, reaching an installed capacity of 584 MW by 2040.

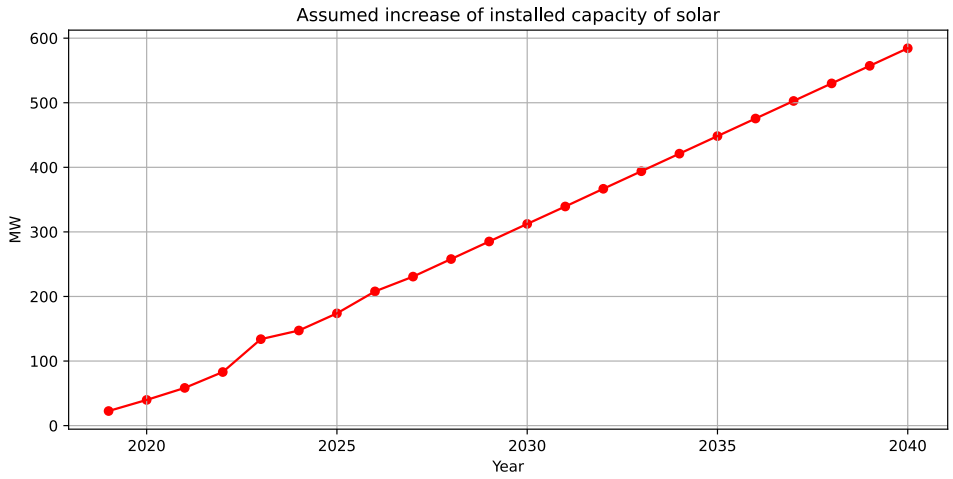


Figure 2.3: Assumed increase of installed solar capacity throughout the modeled time horizon in Gothenburg.

The production curve used for solar power for the model is based on data from a solar power plant in Gothenburg from 2024. No cost are associated with the production of solar power in capacity terms.

2.2.3 Wind power

Besides the 2 MW wind turbine in Gårdsten there are, as previously mentioned, ongoing investigation in connecting a 1000 MW off-shore wind park directly to the local grid in the early 2030's [37]. The project has still not received approval but Göteborg Energi is researching the possibility and impacts of connecting it to the local grid. In this project the impact of including the wind park on total capacity cost was investigated. However, no cost associated with connecting the wind park was considered in the project.

2.2.4 Combined Heat and Power plants

It was assumed as a basis in this project that the local combined heat and power plants produce electricity as base load during the hours of high capacity demand, with a total capacity of 63 to 76 MW depending on the year. However it's possible that the rates at the electricity market is insufficient to make it economical for CHP's to produce electricity during local high load hours, hence the impact of compensating CHP units for the capacity that they provide was also investigated. The assumption is that there is a heat demand, but compensation is required to make it economically feasible to produce electric power. Energiforsk [38] estimated the LCOE of the electricity produced from CHP to 660 SEK/kWh using wood chips as fuel. Although only Sävenäs KVV and Rya BKV uses wood chips as fuel while Renova uses waste a simplification to use this cost for all plants was made. Additionally the impact of no base electricity production from the CHP's was also investigated.

2.3 Case descriptions & scenarios

Four different cases, each with differing levels of import capacity, were investigated. These cases are labeled A through D, and the import capacities of case A through C are presented in table 2.8. Case D is the case when import capacity is a free variable and is to be determined by the model for the year 2040.

Table 2.8: Maximum import capacity per year [MW].

Year	2025-2028	2029-2030	2031-2035	2036-2040
Case A	850	850	850	850
Case B	850	910	1000	1000
Case C	850	910	1000	1250

An additional four different cases were also investigated, focusing on the reimbursement of specifically Rya as previously mentioned and if local flexible resources facilitated by other actors are available or not, meaning that BESS facilitated by other actors (BESS OA), residential batteries, V2G and demand-side flexibility are available or not. The naming convention for these cases are as following.

- Case 1: Capacity from Rya is reserved and compensated on an **daily** basis. Flexibility resources and energy storage's facilitated by other actors are **available**.
- Case 2: Capacity from Rya is reserved and compensated on an **quarterly** basis. Flexibility resources and energy storage's facilitated by other actors are **available**.
- Case 3: Capacity from Rya is reserved and compensated on an **daily** basis. Flexibility resources and energy storage's facilitated by other actors are **unavailable**.

- Case 4: Capacity from Rya is reserved and compensated on an **quarterly** basis. Flexibility resources and energy storages facilitated by other actors are **unavailable**.

In addition the impact of connecting the large-scale wind park Västvind with an installed capacity of 1000 MW, into the local grid, were also investigated.
In total, 32 scenarios were simulated and analyzed. Table 2.9 presents the names of the scenarios.

Table 2.9: Name of scenarios.

Case	**Case A**	**Case B**	**Case C**	**Case D**
Case 1 w\o wind	A1	B1	C1	D1
Case 1 w\wind	$A1_w$	$B1_w$	$C1_w$	$D1_w$
Case 2 w\o wind	A2	B2	C2	D2
Case 2 w\wind	$A2_w$	$B2_w$	$C2_w$	$D2_w$
Case 3 w\o wind	A3	B3	C3	D3
Case 3 w\wind	$A3_w$	$B3_w$	$C3_w$	$D3_w$
Case 4 w\o wind	A4	B4	C4	D4
Case 4 w\wind	$A4_w$	$B4_w$	$C4_w$	$D4_w$

Besides the scenarios presented above was special scenarios constructed regarding costs and availability of CHP along with sensitivity analysis to investigate the impact of the assumptions made.

2.4 Model description

Solving the model for the full time horizon required reducing the amount of variables and constraints in order to reduce the runtime and the memory requirement. This was achieved by only considering the hours around and including those with capacity deficiencies. The capacity deficiency hours are the hours when base electricity production from CHP's, intermittent generation and power import from the regional grid are insufficient to meet the demand, and these hours are defined using a specified time frame, according to equation 2.4.

$$T_H = \{t \mid \forall i \in \{-t_w, ..., t_w\}, D_{t+1}^{Net} > 0\} \tag{2.4}$$

Where D_t^{Net} is calculated according to equation 2.5. For the 2040 model the transmission term cap_t^{trans} is omitted.

$$D_t^{Net} = D_t^{el} - (\sum_{v \in V} g_{v,t}^V + \sum_{l \in L} g_{l,t}^L + cap_t^{trans}), \quad t \in T \tag{2.5}$$

A timeframe of 48 hours around each capacity deficiency hour was selected, meaning that the model also considers 24 hours before and after a deficiency hour. This approach allows energy storage technologies to charge respectively discharge without violating either the state of charge constraint or the demand-supply constraint, while simultaneously reducing the amount of timesteps for the model to solve.

The objective function of respective model is defined in equation 2.6a and 2.6b, and aims to minimize the total cost Ex^{tot} of supplying the projected demand for the corresponding time horizon. The objective function includes running costs of the resources and investment costs of new resources, and for the 2040 model, the fixed, running and investment costs of import capacity.
The base installed import capacity in the 2040 model is 850 MW and can be increased linearly by Δcap_i^{trans} from 850 to 1000 MW and from 1000 to 1250 MW, with corresponding investment cost $Ex_i^{trans-inv}$ per MW. The constraints enforcing sequential investment, i.e that the investment to increase from 1000 to 1250 MW can't occur prior to increasing import capacity to 1000 MW from 850 MW is defined in equations 2.7 - 2.9.

$$\begin{aligned}\min Ex^{\text{tot}} = &\sum_{c\in\mathsf{C}}\sum_{t\in\mathsf{T_H}} g_{c,t}\cdot Ex_c^{Op} \\ &+\sum_{p\in\mathsf{P}}\sum_{t\in\mathsf{T_H}} \Delta Cap_{p,t}\cdot\tau_t\cdot Ex_p^{Inv} \\ &+\sum_{d\in\mathsf{D}} C_d^{res}\cdot Ex_{Rya}^{res} \\ &+\sum_{p\in P}\sum_{q\in Q_H} Cap_{p,q}\cdot Ex_p^{Om} \\ &+\sum_{n\in N}\sum_{t\in T_H}\Delta g_{n,t}\cdot Ex_n^{start}\end{aligned} \tag{2.6a}$$

$$\begin{aligned}\min Ex^{\text{tot}} = &\sum_{c\in\mathsf{C}}\sum_{t\in\mathsf{T_F}} g_{c,t}\cdot Ex_c^{Op} \\ &+\sum_{p\in\mathsf{P}}\sum_{t\in\mathsf{T_F}} \Delta Cap_{p,t}\cdot\tau_t\cdot Ex_p^{Inv} \\ &+\sum_{d\in\mathsf{D}} C_d^{res}\cdot Ex_{Rya}^{res} \\ &+\sum_{p\in P}\sum_{q\in Q_F} Cap_{p,q}\cdot Ex_p^{Om} \\ &+\sum_{n\in N}\sum_{t\in T_F}\Delta g_{n,t}\cdot Ex_n^{start} \\ &+\sum_{t\in T_F} g_t^{trans}\cdot Ex^{trans-Op} \\ &+cap^{trans}\cdot Ex^{trans-subscription} \\ &+\cdot\sum_{i\in I}(\Delta cap_i^{trans}\cdot Ex_i^{trans-inv})\end{aligned} \tag{2.6b}$$

$$Inv_2^{trans} \leq Inv_1^{trans} \tag{2.7}$$

$$\Delta cap_i^{trans} \leq lim_i^{trans}, \forall i \in I \tag{2.8}$$

$$lim_i^{trans} = \begin{cases} 150 & \text{if } i = 1 \\ 250 & \text{if } i = 2 \end{cases}$$

$$Inv_2^{trans} \cdot lim_1^{trans} \leq \Delta cap_1^{trans} \tag{2.9}$$

Equations 2.10 and 2.11 describe which variables are positive and binary respectively.

$$g_t^{trans}, soc_{s,t}, g_{c,t}, BEC_t^E, \Delta Cap_{p,t}, C_d^{res}, Cap_{p,t}, \Delta cap_i^{trans}, \Delta g_{n,t} \geq 0 \tag{2.10}$$

$$Inv_i^{trans}, F_{f,t}^{Activate}, F_{f,t}^{Active}, R_{g,t}^{Active}, R_{g,t}^{Activate} \in \{0, 1\} \tag{2.11}$$

$g_{c,t}$ and $Ex_{c,t}^{Op}$ is the generation and cost of capacity supplying technologies respectively. $\Delta Cap_{p,t}$ is the change of capacity of technologies as a result of new investments with the corresponding investment cost Ex_p^{Inv}. τ_t is the time value of money and is calculated as equation 2.12.

$$\tau_t = \frac{1}{(1+r)^t}, \ t \in T \tag{2.12}$$

Where r is the hourly inflation rate, calculated from an annual inflation rate assumed to be 2% based on the target inflation rate by Sveriges Riksbank [39], see equation 2.13.

$$r = (1 + 0.02)^{\frac{1}{8760}} - 1 \tag{2.13}$$

C_d^{res} is the reserved capacity of Rya at day d for case 1 and 3. The term is modified for case 2 and 4 to cover quarters. Ex_{Rya}^{res} is the corresponding reservation cost.
The reserved capacity is the maximum capacity used by the resource during a day or quarter as defined in equation 2.14.

$$C_d^{res} \geq g_{Rya,t} \quad \forall t \in H_d, \forall d \in D \tag{2.14}$$

Equation 2.15a and 2.15b describes the demand-supply requirement where the demand must be met by the sum of power supplying technologies at each timestep, for the full time horizon and the 2040 model respectively.

$$D_t^{Net} \leq \sum_{m \in M} g_{m,t} - \sum_{s \in S} \Delta soc_{s,t}, \quad \forall t \in T_H \tag{2.15a}$$

$$D_t^{Net} \leq \sum_{m \in M} g_{m,t} - \sum_{s \in S} \Delta soc_{s,t} + g_t^{trans}, \quad \forall t \in T_F \tag{2.15b}$$

Equation 2.16 describes the constraint applying to new investment in gas turbines, that the production can't exceed the installed capacity.

$$g_{GT,t} \leq cap_{GT,t}, \quad \forall t \in T \tag{2.16}$$

The charging and discharging of stationary battery energy storages are limited by equation 2.17, where $CH_{s,t}^{cap}$ and $DCH_{s,t}^{cap}$ are parameters which represents the discharge and charge capacity of each storage s at timestep t, $Cap_{BGP,t}$ is a variable representing the discharge and charge capacity of large-scale BESS that is invested in by the model.

The state of charge of the stationary storage in the full time horizon model are described by equation 2.18 and 2.19, these apply to energy storages facilitated by other actors and to BESS that can be invested in, equation 2.19 is modified for the corresponding timeset T_F for the 2040 model.

$$-DCH_{s,t}^{cap} \leq \Delta soc_{s,t} \leq CH_{s,t}^{cap}, \quad \forall t \in T, \forall s \in SS \tag{2.17a}$$
$$-Cap_{BGP,t} \leq \Delta soc_{BG,t} \leq Cap_{BGP,t}, \quad \forall t \in T \tag{2.17b}$$

$$soc_{s,t} \leq soc_{s,t}^{cap}, \quad \forall t \in T, \forall s \in SS \tag{2.18a}$$
$$soc_{BGS,t} \leq Cap_{BGS,t}, \quad \forall t \in T \tag{2.18b}$$

$$\forall t \in T_H, \forall s \in SS, soc_{s,t} = \begin{cases} soc_{s,t-1} + \Delta soc_{s,t-1} & \textbf{if } t-1 \in T_H \\ soc_{s,t}^{cap} & \textbf{if } t-1 \notin T_H \end{cases} \tag{2.19}$$

In the model there is no cost associated with charging of energy storage, only discharging. $g_{s,t}$ represents the discharged power from storage s at timestep t and is constrained by equation 2.20.

$$g_{s,t} \geq -\Delta soc_{s,t} \quad \forall t \in T, \forall s \in S \tag{2.20}$$

Changes to installed capacity are tracked using the variable $\Delta Cap_{p,t}$ with equation 2.21.

$$\Delta Cap_{p,t} = Cap_{p,t} - Cap_{p,t-1} \quad \forall t, t-1 \in T, \forall p \in P \tag{2.21}$$

V2G is modeled similarly as stationary battery storage's but with some key differences. The car fleet is represented as a collective and no variable is tracking the state of charge of the collective. However, the energy taken from the fleet is tracked with the variable BEC_t^E. This variable is constrained to return to zero by the end of a deficiency period for the full time horizon model, and by 6 am each day in the 2040 model defined by equation 2.22a and 2.22b. The possible discharge from the fleet is limited by the cumulative energy taken from the fleet defined in equation 2.23-2.24.

$$BEC_t^E = 0, \quad t \in T_H, t+1 \notin T_H \tag{2.22a}$$
$$BEC_t^E = 0, \ \forall t \in T_F : t \ mod \ 24 = 6 \tag{2.22b}$$

$$BEC_t^E = BEC_{t-1}^E - \Delta soc_{V2G,t-1}, \quad \forall t, t-1 \in T \tag{2.23}$$

$$V2G_t^{available} - BEC_t^E \geq \Delta soc_{V2G,t}, \quad \forall t \in T \tag{2.24}$$

Equations 2.25-2.29 describes the constraints applied on Rya regarding upper and lower load level and equation 2.30 ensures that the steam turbine can't be operated independently of the gas turbines.

$$g_{Rya,t} \leq RyaGT^{cap} * R^{Active}_{GT,t} + RyaST^{cap}_{t} * R^{Active}_{ST,t}, \ \forall t \in T \tag{2.25}$$

$$g_{Rya,t} \geq R^{Active}_{GT,t} * MLL_{GT} + R^{Active}_{ST,t} * MLL_{ST}, \ \forall t \in T \tag{2.26}$$

$$R^{Activate}_{g,t} \geq R^{Active}_{g,t} - R^{Active}_{g,t-1}, \ \forall g \in G, \forall t, t-1 \in T \tag{2.27}$$

$$R^{Activate}_{g,t} \leq R^{Active}_{g,t-1}, \ \forall g \in G, \forall t, t-1 \in T \tag{2.28}$$

$$R^{Activate}_{g,t} \leq 1 - R^{Active}_{g,t-1}. \ \forall g \in G, \forall t, t-1 \in T \tag{2.29}$$

$$R^{Active}_{ST,t} \leq R^{Active}_{GT,t}, \ \forall t \in T \tag{2.30}$$

The increase in generation of gas turbines which is associated with a start up cost is tracked by the variable $\Delta g_{n,t}$ defined by equation 2.31 for the full time horizon- and 2040 model respectively.

$$\forall t \in T_H, \forall n \in N \quad \Delta g_{n,t} \geq \begin{cases} g_{n,t} - g_{n,t-1}, & \text{if } t-1 \in T_H \\ g_{n,t}, & \text{if } t-1 \notin T_H \end{cases} \tag{2.31a}$$

$$\forall t \in T_F, \forall n \in N \quad \Delta g_{n,t} \geq \begin{cases} g_{n,t} - g_{n,t-1}, & \text{if } t-1 \in T_F \\ g_{n,t}, & \text{if } t-1 \notin T_F \end{cases} \tag{2.31b}$$

Equations 2.32-2.35 describes the constraints applying to the demand-side flexibility resources in the full time horizon model, the equations are modified for the 2040 model with the corresponding time-set.
The reduction in demand of a demand-side flex resource is limited by its current capacity and whether it's active or not. The variable $F^{Activate}_{f,t}$ is a variable tracking when a resource becomes active. As it is assumed that an resource can only be active during a number of consecutive hours before it must recover.

$$g_{Flexibility,t} = \sum_{f \in F} F^{cap}_{f,t} * F^{active}_{f,t}, \quad \forall t \in T_H \tag{2.32}$$

$$\forall t \in T_H, \forall f \in F \quad F^{Activate}_{f,t} \geq \begin{cases} F^{Active}_{f,t} - F^{Active}_{f,t-1}, & \textbf{if } \ t-1 \in T_H \\ F^{Active}_{f,t} & \textbf{if } \ t-1 \notin T_H \end{cases} \tag{2.33}$$

$$\sum_{t=t_i}^{t_i+F^{rec}_f} F^{Active}_{f,t} \leq F^{end}_f \quad \forall ti, ti + F^{rec}_f \in T_H, \forall f \in F \tag{2.34}$$

$$\sum_{t=ti}^{ti+F^{rec}_f} F^{Activate}_{f,t} \leq 1, \quad \forall ti, ti + F^{rec}_f \in T_H, \forall f \in F \tag{2.35}$$

3
Results

In this chapter is the results of each scenario presented along with comparisons of the different import capacity levels.

3.1 Results from case A - D

This section presents the results of the scenarios within each import-capacity case. The import capacity costs associated with each case are not included in this section but are compared in the subsequent section.

3.1.1 A - 850 MW import capacity

With a limited import capacity the system is dependent on maximizing the usage of existing resources and also need to invest in new resources. The total cost of scenario A1, A2, A3 and A4 can be seen Figure 3.1. In all of the scenarios investments was made in new gas turbines. The capacity of BESS- and GT investments can be seen in Table 3.1. For scenario A4 significant investments were made in gas turbines already in 2027.

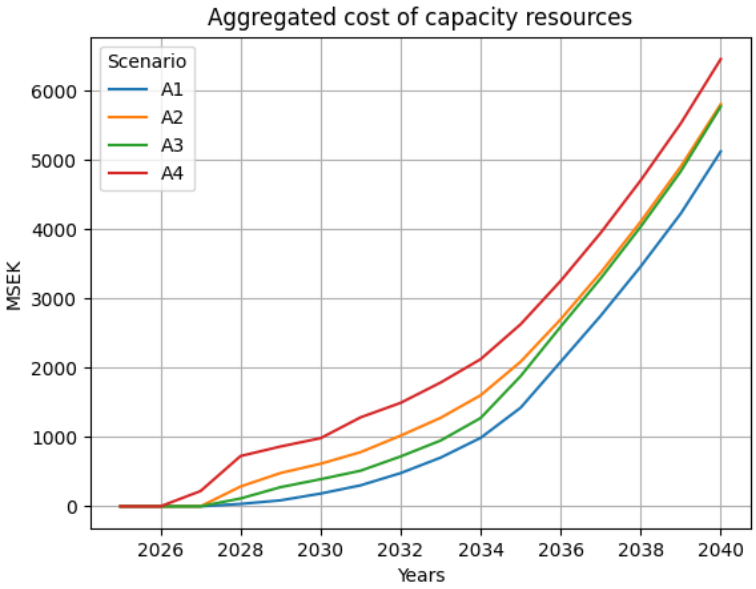


Figure 3.1: Aggregated cost of capacity resources for case A.

Connecting the large-scale wind park will reduce the cost dramatically since it removes a significant share of the energy that had to be covered by capacity resources, see Figure 3.2. However it doesn't significantly reduce the required capacity of new resources, as can be seen in Table 3.1 where all new investments are presented for each scenario. As in the no wind case, there is significant investments from 2027 in gas turbines in scenario $A4_w$. While for $A3_w$ battery investments and utilization of Rya offset gas turbine investments until 2035. $A1_w$ and $A2_w$ has spread cost over all capacity resources however $A2_w$ have larger costs for Rya compared to $A1_w$ due to the quarterly reservations.

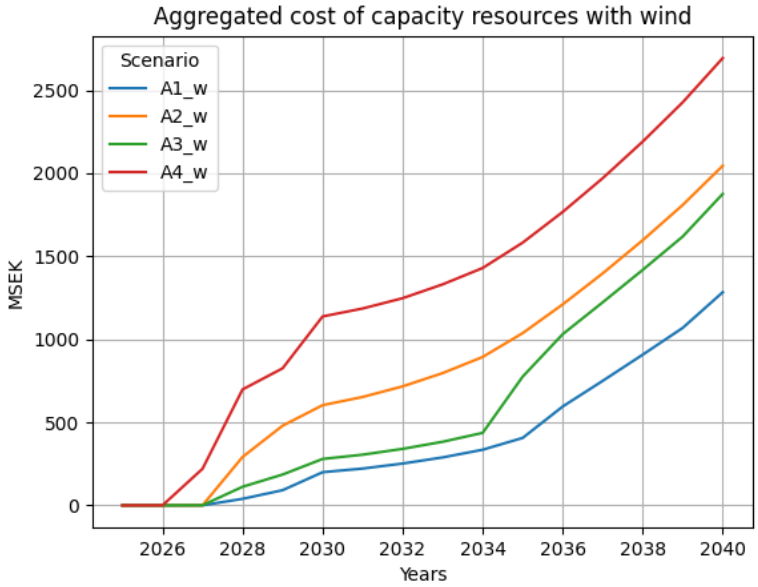


Figure 3.2: Aggregated cost of capacity resources for case A with wind.

Table 3.1: Installed capacities of new investments in 2040.

Scenario	BESS Storage capacity [MWh]	BESS Power capacity [MW]	GT capacity [MW]
A1	0	0	54
$A1_w$	0	0	54
A2	0	0	63
$A2_w$	0	0	63
A3	56	25	98
$A3_w$	26	16	107
A4	51	28	99
$A4_w$	26	16	107

The cost per MW provided without wind can be seen in Table 3.2. It's calculated as the total costs of using each resource divided with the total capacity provided in the time horizon. Since Rya CCGT is used frequently the cost of using the plant approaches the fuel costs ($1900 SEK/MWh_{el}$). Due to covering the full investment

of new gas turbines plus operational costs the cost per MW provided will be significantly higher compared to Rya CCGT.

Table 3.2: Cost per MW for scenario A1–A4.

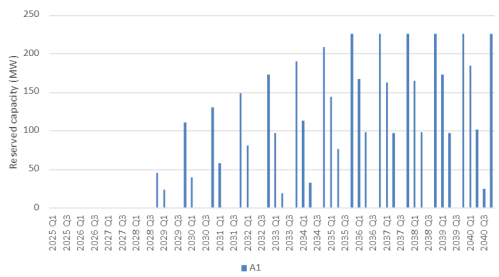
Cost per MW	**A1**	**A2**	**A3**	**A4**
Rya CCGT	2201	2484	2220	2477
New gas turbines	5594	4715	6315	5213
Flex	2011	1966	-	-
BESS GENAB	-	-	3237	3287
Total	2372	2691	2622	2938

Table 3.3 shows the cost per MW capacity provided by the different capacity resources with wind. With less frequent activation the fixed cost of long reservations in $A2_w$ and $A4_w$ will make up a larger share of the cost for Rya CCGT compared to the corresponding no wind cases. The cost per MW for gas turbines increases even more due to a low amount of activations.

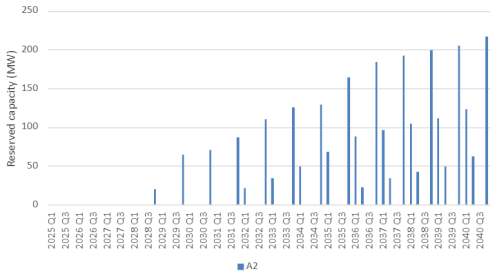
Table 3.3: Cost per MW with wind for scenario $A1_w$–$A4_w$.

Cost per MW	$A1_w$	$A2_w$	$A3_w$	$A4_w$
Rya CCGT	2420	4904	2534	4718
New gas turbines	11316	13586	12611	13442
Flex	2095	1962	-	-
BESS GENAB	-	-	7509	7182
Total	3336	5388	4763	6864

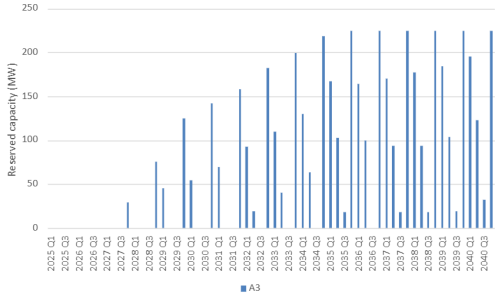
Figure 3.3 shows the quarterly reservation of Rya CCGT for the A-scenarios without the large scale wind park connected. Without import capacity extensions, Rya has to be utilized extensively. Mainly in Q1 and Q4, but also in Q2 in the later years of the time horizon due to demands in mainly April.



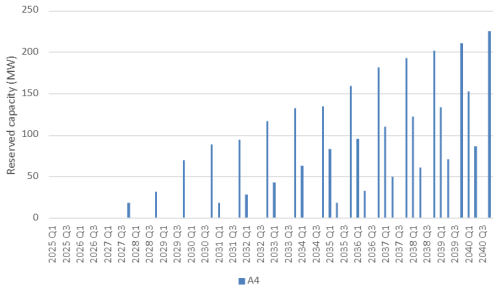
(a) A1



(b) A2



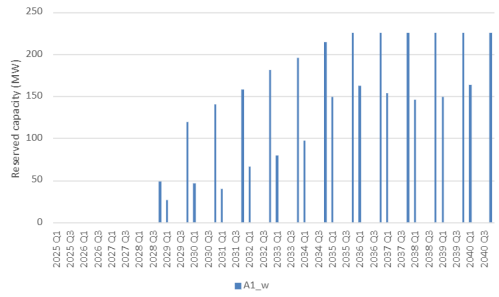
(c) A3



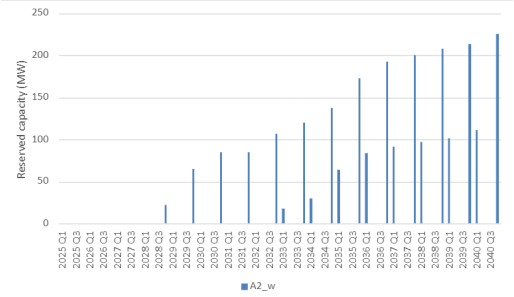
(d) A4

Figure 3.3: Capacity reserved per quarter from Rya CCGT.

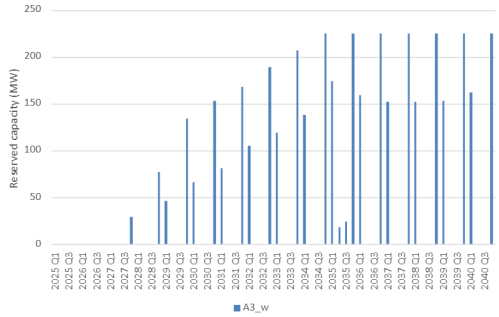
Figure 3.4 shows the quarterly reservation of Rya CCGT for the A-scenarios with the large-scale wind park connected. The result is similar as to without wind except reservations in Q2. This means that Rya CCGT needs to be reserved in the same way both with and without wind, in order to handle the variations of wind.



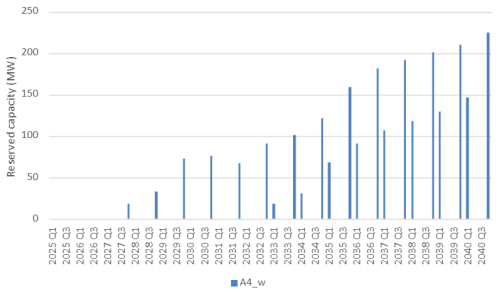
(a) $A1_w$



(b) $A2_w$



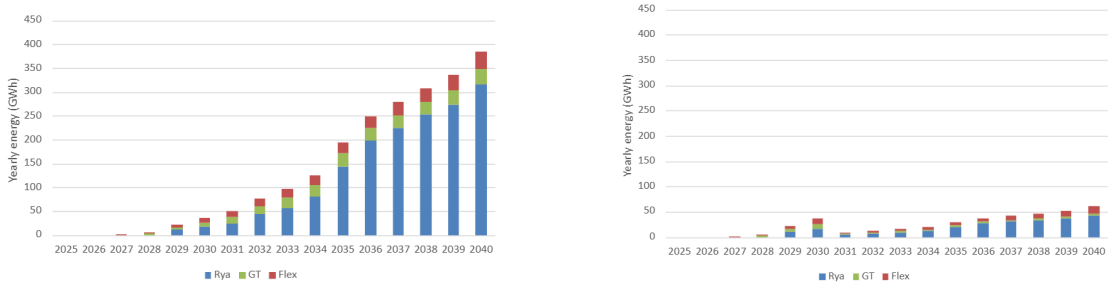
(c) $A3_w$



(d) $A4_w$

Figure 3.4: Capacity reserved per quarter from Rya CCGT, with wind connected.

Using A2 as reference scenario, in Figure 3.5a the yearly energy provided from the dispatched resources can be seen with and without wind. Rya is clearly providing most energy, especially without wind. Adding wind to the system reduces the energy provided significantly even though the reservation levels of Rya and invested capacity for gas turbines are almost the same.



(a) $A2$ **(b)** $A2_w$

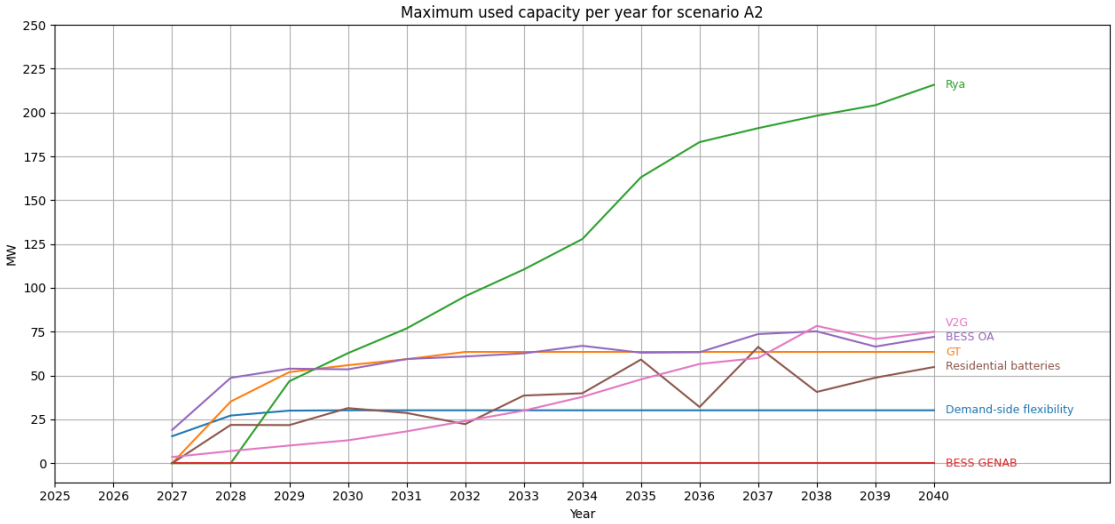
Figure 3.5: Yearly energy provided by capacity resources.

Table 3.4 shows the yearly active hours and energy sum of the aggregated flexible resources for scenario A2 and $A2_w$. The amount of activated hours increases over the years and in 2040 amounts to over 20% of the hours of the year with an average of 18 MWh per activated hour implying dependency and significant usage of flexible resources facilitated by other actors. With wind the activated hours and energy drop significantly with less hours of demand and large fluctuations of intermittent production covered by gas turbines.

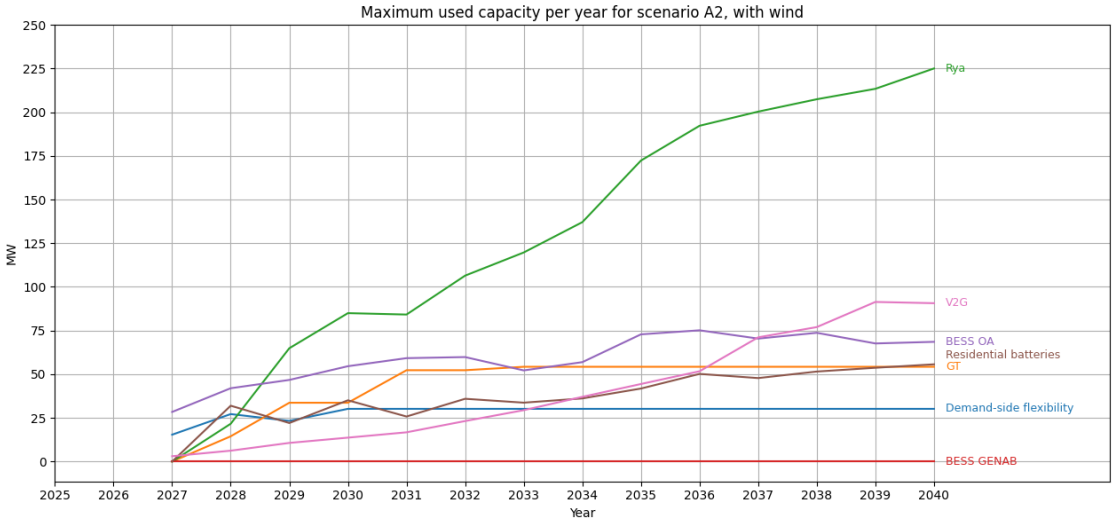
Table 3.4: The yearly active hours and energy from the aggregated flexible resources for A2 & $A2_w$.

Year	A2 active hours	A2 energy [MWh]	$A2_w$ active hours	$A2_w$ energy [MWh]
2025	0	0	0	0
2026	0	0	0	0
2027	9	134	9	134
2028	113	1656	120	1955
2029	440	6338	446	6496
2030	653	9965	654	10040
2031	796	12835	107	2281
2032	953	15253	135	3020
2033	1059	16663	161	3629
2034	1147	19082	197	4352
2035	1365	22339	246	5670
2036	1426	24053	298	6846
2037	1529	26336	342	8195
2038	1625	28664	374	9597
2039	1761	31808	411	11117
2040	1963	36918	481	13508

Figure 3.6 presents the maximum used capacity of the different resources with and without wind for A2. In both scenarios are all of the energy storages fully cycled. There are minor differences of maximum capacity used with wind and without wind, the reason is likely due to different amount of hours of capacity deficiencies, leading to different optimal usages. However, the results shows that with wind a similar level of capacity from resources is used, but as shown in Table 3.4, for a significant lower amount of hours.



(a) $A2$



(b) $A2_w$

Figure 3.6: Maximum used capacity per resource, per year.

Figure 3.7 shows the aggregated cost of A2 looking at three different scenarios related to the electricity production from the CHPs. In the base case there is no compensation towards the CHP's for capacity, assuming that they produce power on the intra-day market. The orange curve shows the case when there is a heat demand but the power produced needs to be compensated for with an estimated

levelized cost of electricity of 660 SEK / MWh. The green curve shows A2 without the assumed base power production from CHPs.

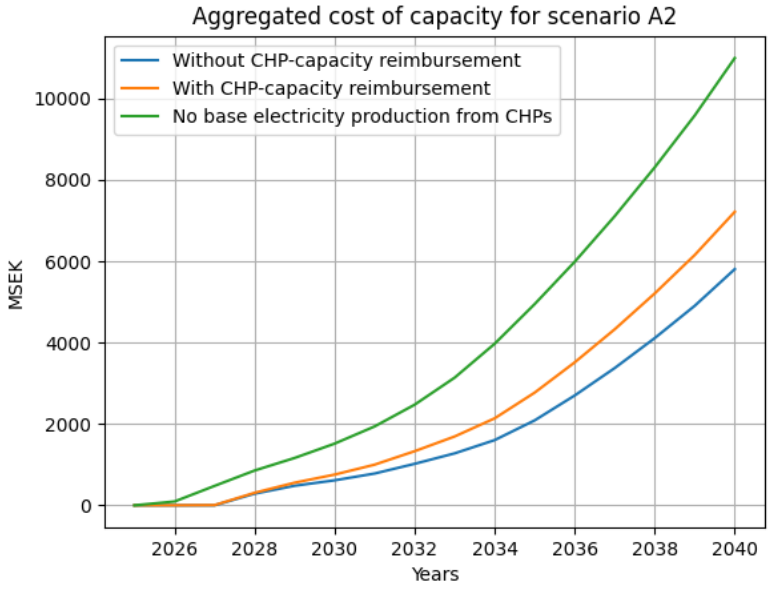


Figure 3.7: Capacity resource cost with and without reimbursement for base CHP-production, and cost without base electricity production from CHPs.

Table 3.5 shows the system cost with and without power production from the CHP's for A2, along with the value per produced MWh for the system.

Table 3.5: The system cost with and without CHP base production for scenario A2.

	Cost with CHP (MSEK)	Cost without CHP (MSEK)	Value (SEK/MWh)
A2	5806	10995	2430

3.1.2 B - 1000 MW import capacity

The aggregated costs of capacity resources for scenarios B1, B2, B3 and B4 can be seen in Figure 3.8. It was only in case B4 that new investments of batteries and gas turbine occurred, the battery capacity found optimal was 21 MW / 23 MWh and the gas turbine capacity was 6.7 MW, where the major investments occurred in 2027. The reason for the small investments in gas turbines even though there is spare capacity at Rya is likely due to the minimum load level set for Rya at 18 MW. Comparing the costs of B1 with B2, and B3 with B4 shows the impact of the reservation length of Rya CCGT. Comparing the costs of B1 with B3, and B2 with B4 shows the value of using flexible resources from other actors.
Figure 3.9 shows the system costs when connecting the large-scale wind park. The reason the cost reduction is more significant in B1 and B3 is due to the short reservation periods of Rya CCGT, as it can be used flexibly to a lower cost compared

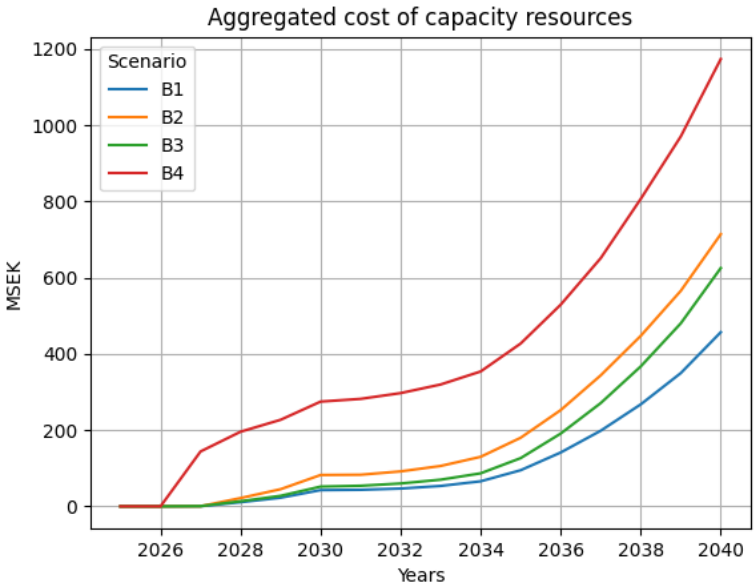


Figure 3.8: Aggregated costs of capacity resources for case B.

to the quarterly reservation scenarios. Adding wind resulted in no investment in gas turbines, and only in $B4_w$ was a battery invested in with capacity 5 MW / 5 MWh.

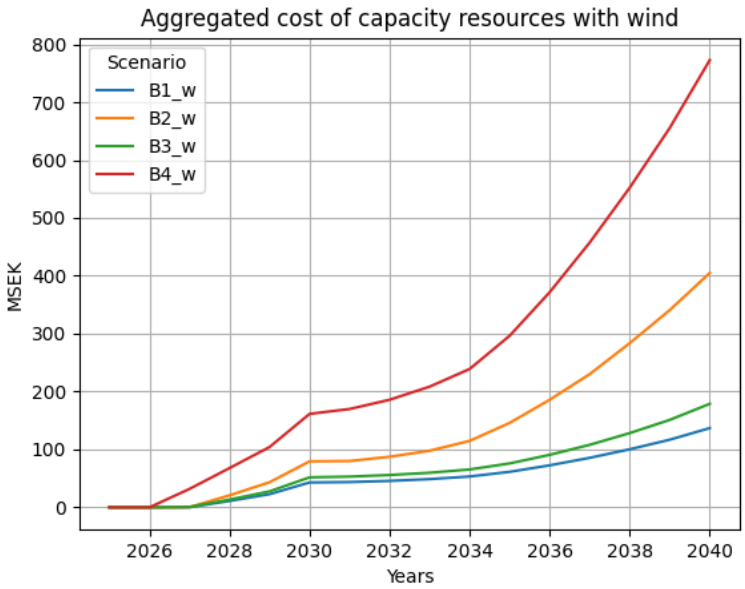


Figure 3.9: Aggregated costs of capacity resources for case B with wind.

In all of the scenarios is Rya CCGT the largest capacity source, both in terms of energy provided and maximum power provided. Depending on the scenario the overall cost per MW capacity will differ. Table 3.6 shows the average cost for the capacity used from Rya CCGT, new investments and flexible resources for the whole period without wind, where the flexible resources consists of demand-side flexibility,

BESS OA, Residential batteries and V2G. The table show that the long reservation periods of Rya CCGT results in significantly higher cost per capacity provided.

Table 3.6: Cost per MW provided for scenario B1–B4.

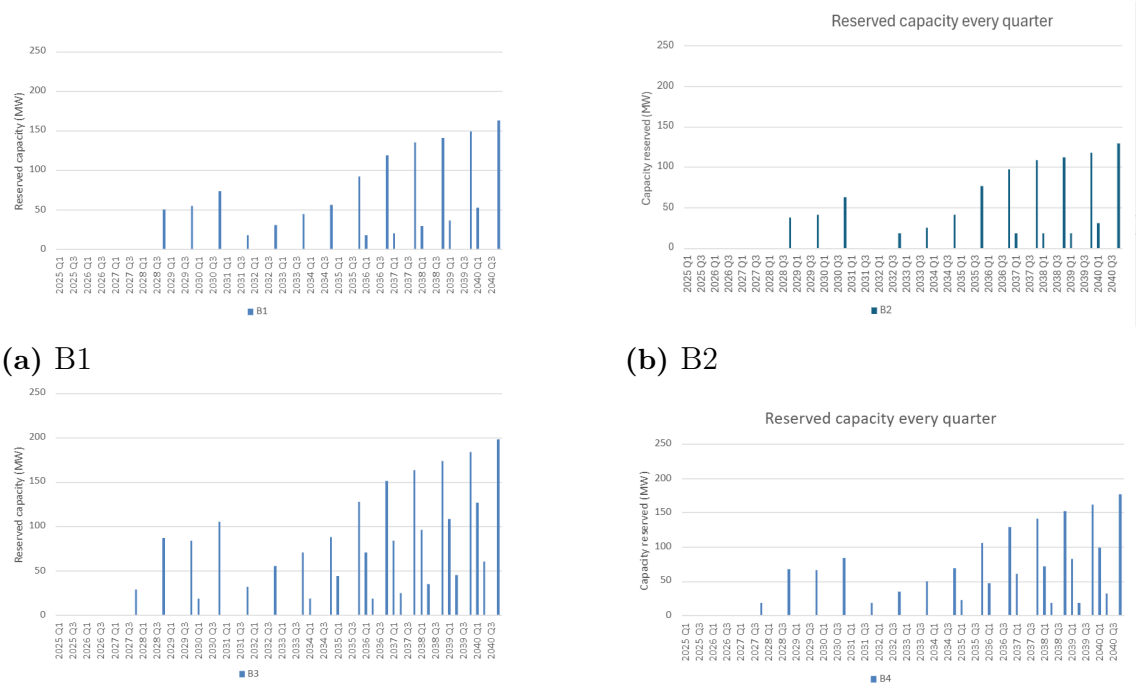
Cost per MW	**B1**	**B2**	**B3**	**B4**
Rya CCGT	2375	4244	2863	5084
New gas turbines	-	-	-	16119
Flex	1930	1902	-	-
BESS GENAB	-	-	-	8668
Total	2210	3464	2863	5646

Table 3.7 shows the average cost for the capacity used from Rya CCGT and flexible resources for the whole period but with wind installed. Here, the cost increase per unit of produced capacity is even more significant with long reservations. With wind installed there is a lower energy demand from Rya CCGT, but as mentioned earlier, similar levels of capacity must still be reserved to compensate for the intermittency of wind.

Table 3.7: Cost per MW for scenario $B1_w$–$B4_w$.

Cost per MW	$B1_w$	$B2_w$	$B3_w$	$B4_w$
Rya CCGT	2438	9302	2903	12386
Flex	2030	2054	-	-
BESS GENAB	-	-	-	28997
Total	2269	6836	2903	12655

Figure 3.10 shows the maximum reserved capacity of Rya CCGT for every quarter for each scenario, reservations are mainly made in Q1 and Q4 for all scenarios as that is when the highest loads during the year typically occur. Here, the availability of flex resources have the largest impact of the reservation level. B3 and B4 (without flex) require higher levels of reserved capacity compared to B1 and B2, additionally reservations are also needed in Q2 from 2036 onward. The maximum capacity of Rya excluding the base load of 30 MW is 225 MW, meaning that that there still is some capacity left to use in all scenarios as can be seen in the figures.

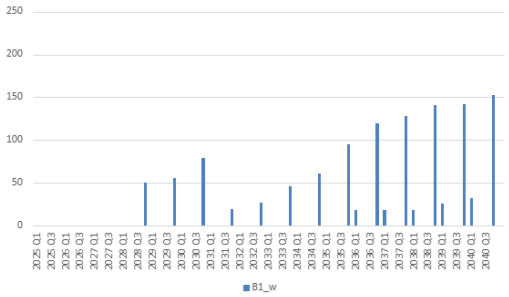


(a) B1 **(b)** B2

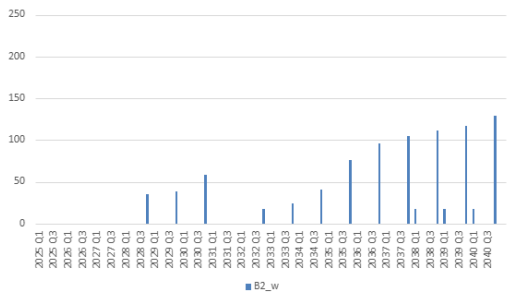
(c) B3 **(d)** B4

Figure 3.10: Capacity reserved per quarter from Rya CCGT.

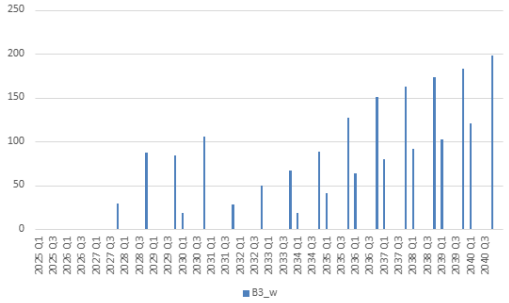
Figure 3.11 shows the maximum reserved capacity of Rya CCGT for every quarter for each scenario when connecting the large-scale wind park. Comparing the results with the reservation without wind they are nearly identical, besides the smaller reservations in Q3 for B3 and B4. This indicate that Rya CCGT will have the same amount of fixed cost covered with or without wind and it is only the operational costs that will differ. It also shows that the availability of Rya CCGT is as crucial with or without wind.



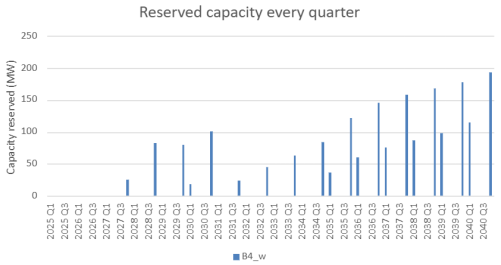
(a) $B1_w$



(b) $B2_w$



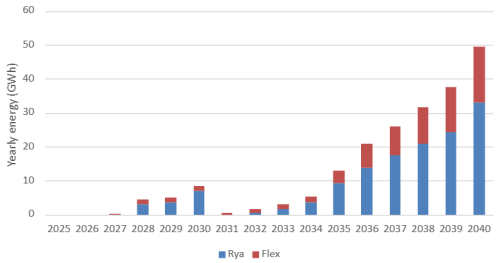
(c) $B3_w$



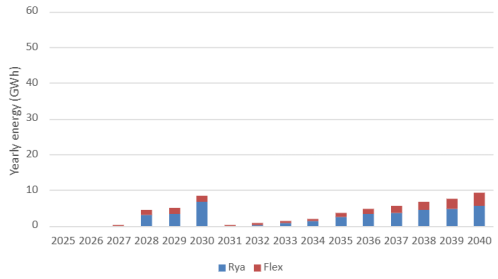
(d) $B4_w$

Figure 3.11: Capacity reserved per quarter from Rya CCGT with wind.

In Figure 3.12a can the yearly energy used from the different capacity resources be seen with and without wind for B2. Compared to A2 the energy provided is much lower and the share of the energy provided from flexible resources are greater. With wind in the system are between a third and one half of the capacity provided by flexible resources.



(a) $B2$



(b) $B2_w$

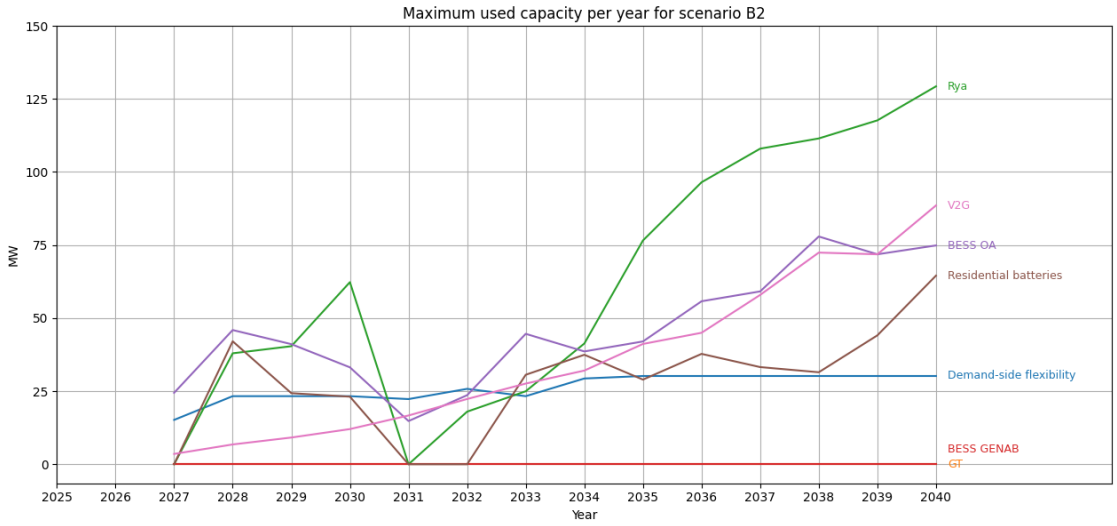
Figure 3.12: Yearly energy provided by capacity resources.

Table 3.8 shows the yearly active hours and energy for the aggregated flexible resources using B2 as a reference scenario, with and without wind. The number of active hours and energy decreases in 2031 due to the connection of the wind park and that import capacity increases to 1000 MW. The active hours is spread out for all the flexible resources and the average capacity per active hour is between 13-20 MW without wind and 13-30 MW with wind. Implementing wind reduces the amount of hours that flexible resources are needed significantly.

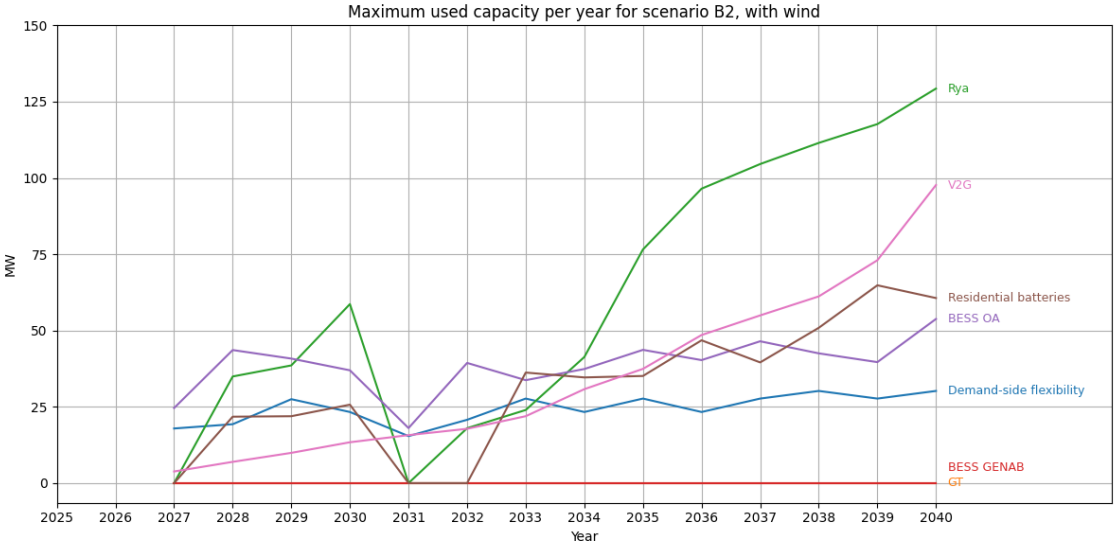
Table 3.8: The yearly active hours and energy for the aggregated flexible resources for B2 and $B2_w$.

Year	B2 active hours	B2 energy [MWh]	$B2_w$ active hours	$B2_w$ energy [MWh]
2025	0	0	0	0
2026	0	0	0	0
2027	9	134	9	134
2028	97	1317	102	1455
2029	101	1276	115	1501
2030	138	1606	152	1902
2031	25	336	19	279
2032	70	1014	30	552
2033	91	1426	33	665
2034	123	1745	39	724
2035	237	3523	51	957
2036	384	6977	72	1597
2037	455	8315	82	1943
2038	538	10899	94	2292
2039	603	13320	99	2638
2040	715	16467	112	3484

Figure 3.13 shows the maximum used capacity for each resource per year for scenario B2. Similar to scenario A2, the maximum energy storage capacity is used for the energy storages. The maximum capacity used per year and resource is similar with and without wind and the differences are due to different optimal usages.



(a) $B2$



(b) $B2_w$

Figure 3.13: Maximum used capacity per resource, per year.

Using B2 as a reference scenario, the cost increase of reimbursing CHP for the capacity they provide aswell as the total cost of no electricity production from CHP can be seen in Figure 3.14.

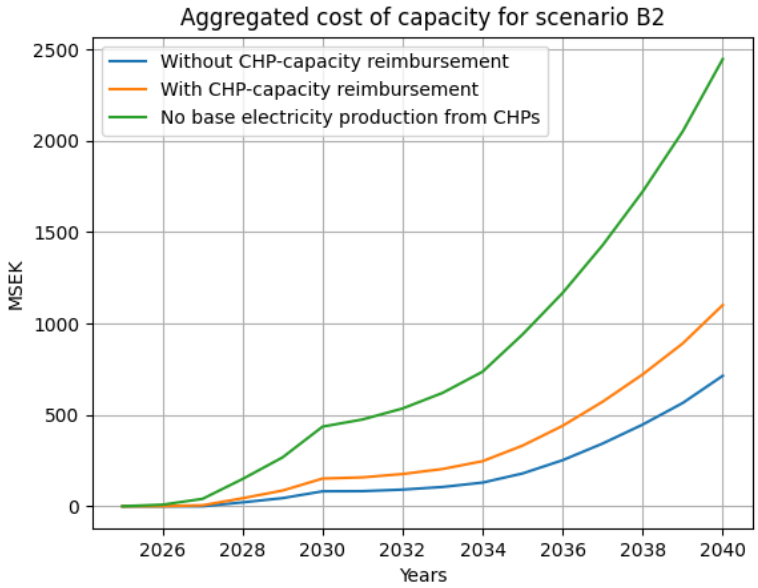


Figure 3.14: Capacity resource cost with and without reimbursement for base CHP-production, and cost without base electricity production from CHPs.

Table 3.9 shows the system cost with and without power production from the CHPs for B2, along with the value per produced MWh for the system.

Table 3.9: The system cost with and without CHP base production for B2 without wind.

	Cost with CHP (MSEK)	Cost without CHP (MSEK)	Value (SEK/MWh)
B2	714	2446	2953

3.1.3 C - 1250 MW import capacity

The aggregated costs for the capacity resources in C is lower than in B since more power can be imported from the regional grid. The aggregated costs for C1, C2, C3 and C4 can be found in Figure 3.15. The costs are, up to the increased import capacity from 1000 MW to 1250 MW in 2036, almost inseparable from the respective scenario in B. After 2036 there is no further need for capacity resources. In none of the scenarios were new gas turbines or BESS invested in.

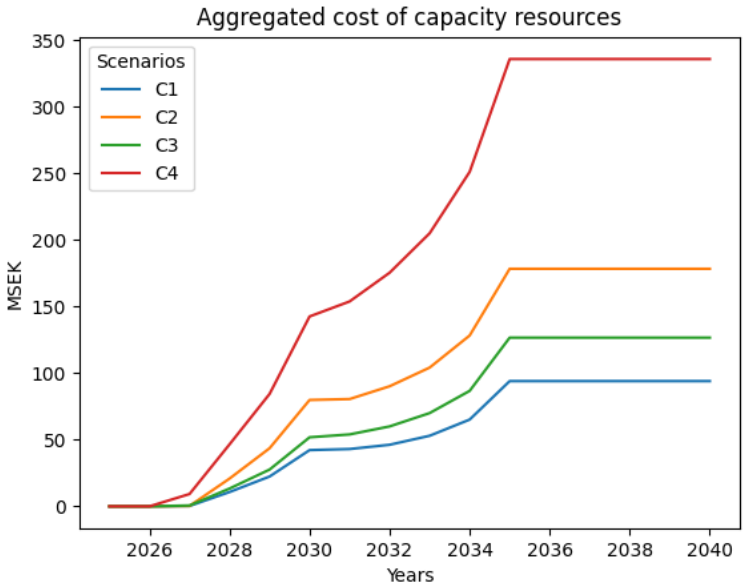


Figure 3.15: Aggregated cost of capacity resources for case C.

Figure 3.16 show the aggregated costs of capacity with wind installed. The reduction of costs are less for the scenarios in C compared to A and B. With the import capacity extension to 1250 MW in 2036, the cost benefits of wind will not be as significant.

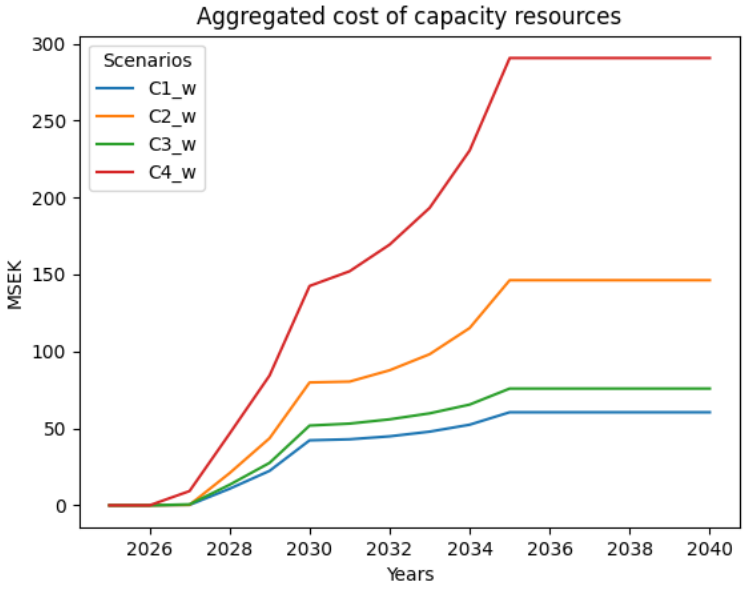


Figure 3.16: Aggregated cost of resources for case C with wind.

Table 3.10 shows the average capacity cost for the aggregated flex resources and Rya CCGT for scenario C1-C4.

Table 3.10: Cost per MW for scenario C1–C4.

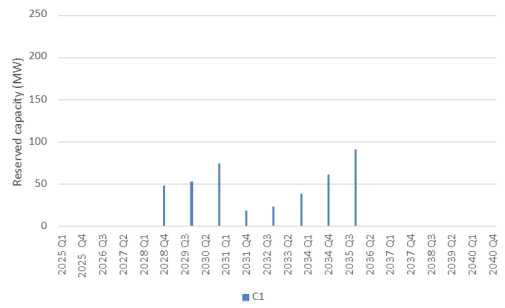
Cost per MW	C1	C2	C3	C4
Rya CCGT	2436	5607	2842	7538
Flex	2121	2127	-	-
Total	2314	4389	2842	7538

Table 3.11 shows the average capacity cost for the aggregated flex resources and Rya CCGT for scenario $C1_w$-$C4_w$.

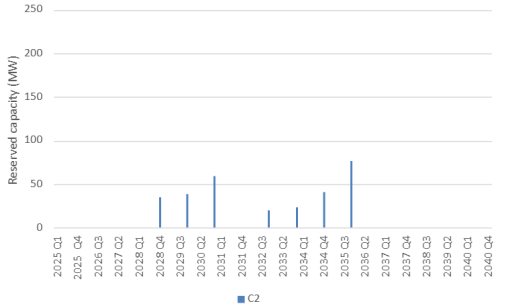
Table 3.11: Cost per MW for scenario $C1_w$-$C4_w$.

Cost per MW	$C1_w$	$C2_w$	$C3_w$	$C4_w$
Rya CCGT	2453	7412	2790	10685
Flex	2200	2247	-	-
Total	2314	4389	2790	10685

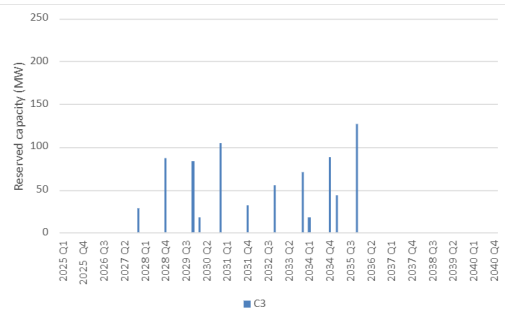
Figure 3.17 shows the quarterly reservation of Rya CCGT for the C scenarios. The maximum capacity used is 130 MW in C3.



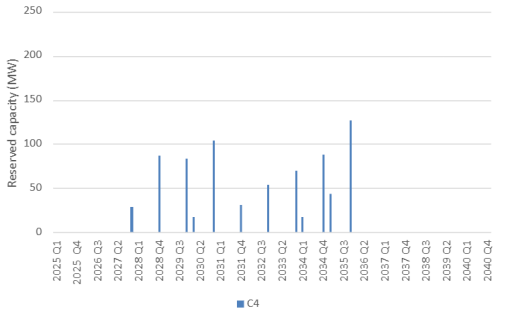
(a) C1



(b) C2



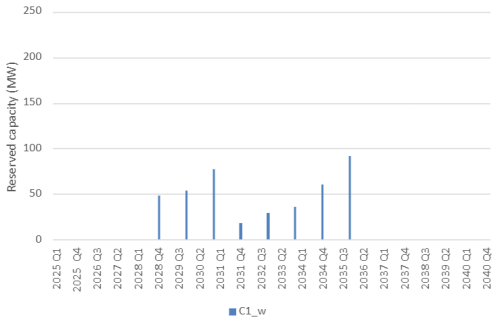
(c) C3



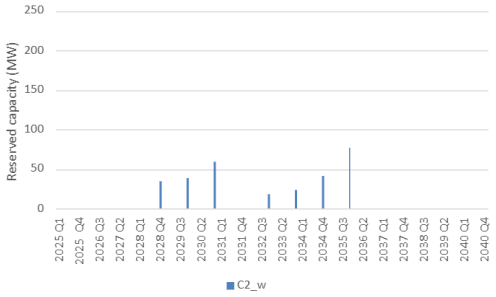
(d) C4

Figure 3.17: Capacity reserved per quarter from Rya CCGT.

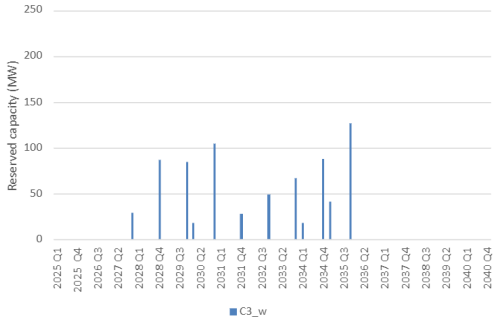
Figure 3.18 shows the quarterly reservation of Rya CCGT for the scenarios within C with wind. As can be seen from the figure, same as the previous cases, including wind will not significantly reduce the capacity required by capacity resources such as Rya CCGT.



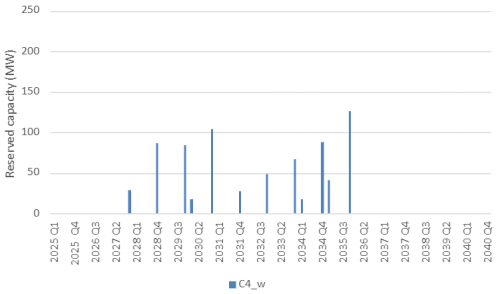
(a) $C1_w$



(b) $C2_w$



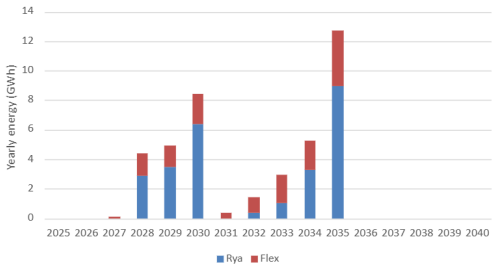
(c) $C3_w$



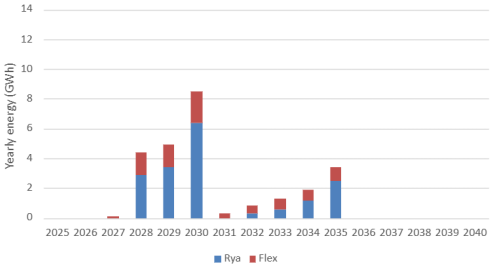
(d) $C4_w$

Figure 3.18: Capacity reserved per quarter from Rya CCGT.

In Figure 3.19 the yearly energy provided can be seen from the capacity resources for C2 with and without wind. In this case adding wind will not have as significant impact on capacity cost compared to case A and B, due to the import capacity increase at 2036.



(a) $C2$



(b) $C2_w$

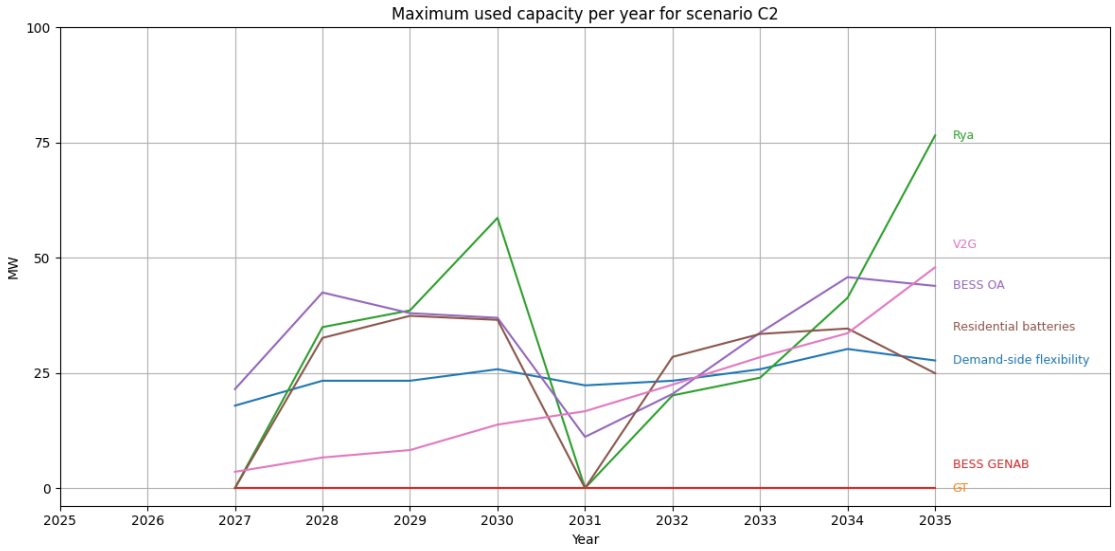
Figure 3.19: Yearly energy provided by capacity resources.

Table 3.12 shows the yearly active hours and energy from the aggregated flexible resources in C2 and $C2_w$.

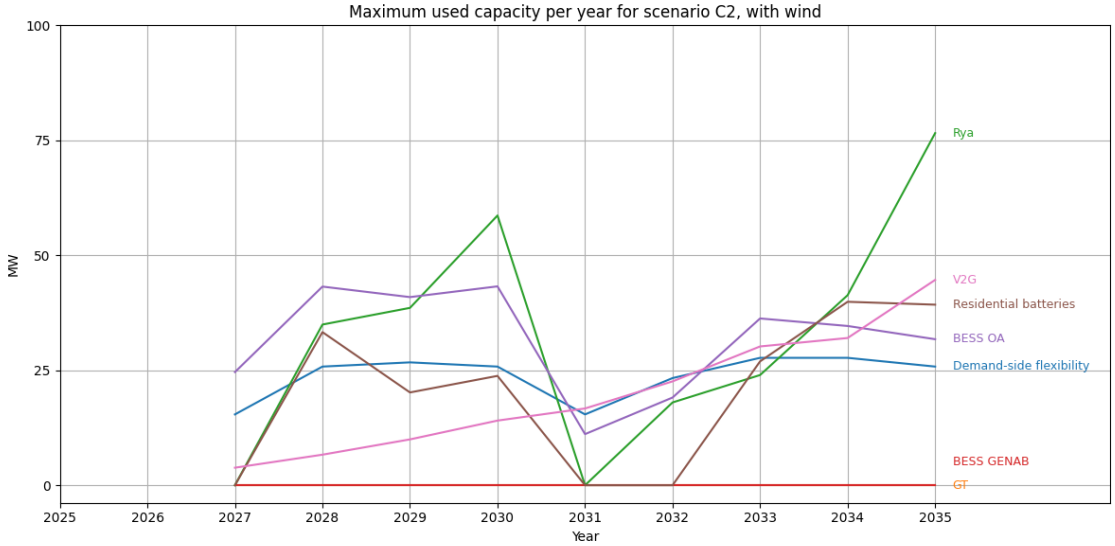
Table 3.12: Activated hours and energy per year from the aggregated flexible resources for scenario C2 and $C2_w$.

Year	C2 active hours	C2 energy [MWh]	$C2_w$ active hours	$C2_w$ energy [MWh]
2025	0	0	0	0
2026	0	0	0	0
2027	9	134	9	134
2028	101	1479	101	1492
2029	108	1451	108	1513
2030	153	2087	153	2077
2031	25	336	19	279
2032	72	1083	30	516
2033	100	1890	33	737
2034	123	1935	39	715
2035	242	3791	51	957
2036	0	0	0	0
2037	0	0	0	0
2038	0	0	0	0
2039	0	0	0	0
2040	0	0	0	0

Figure 3.20 presents the maximum hourly capacity used from the capacity resources with and without wind for scenario C2 until 2035. Compared to the lower import cases, the full capacity of the energy storage are not used in the same extent. The difference with or without wind is mainly the different maximum hourly capacity provided by BESS OA and residential batteries, which only is a matter of how to disperse the energy content of the batteries optimally.



(a) $C2$



(b) $C2_w$

Figure 3.20: Maximum used capacity per resource, per year.

As the previous cases, the cost and availability of CHP was investigated. Using C2 as a reference scenario the resulting cost can be seen in Figure 3.21.

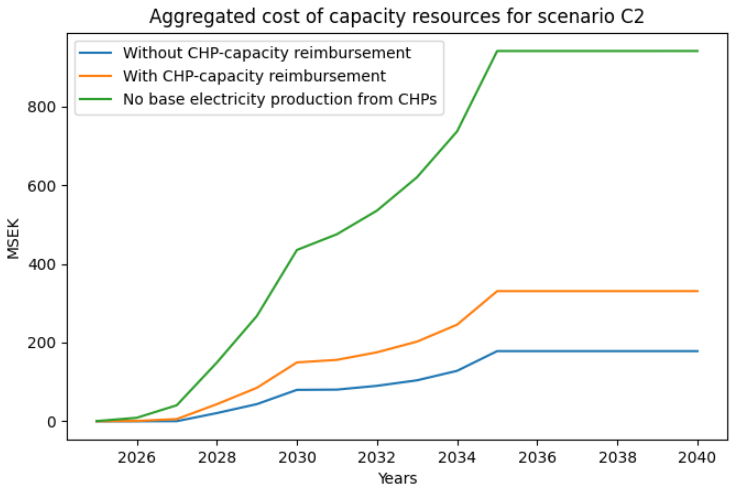


Figure 3.21: Aggregated cost with and without reimbursement for base CHP-production, and cost without base electricity production from CHP.

Table 3.13 shows the cost of having CHP available or not and what the value is per MWh produced.

Table 3.13: The system cost with and without CHP base production for C2 without wind.

	Cost with CHP (MSEK)	Cost without CHP (MSEK)	Value (SEK/MWh)
C2	178	936	3287

3.1.4 D - Variable import capacity for 2040

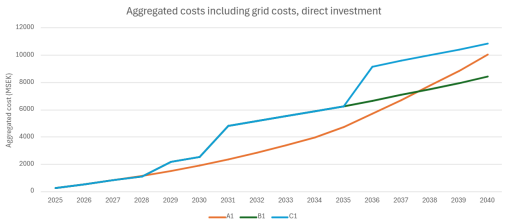
The optimal import capacity for the modeled year 2040 are presented in Table 3.14 for all case D scenarios. There were no scenarios without wind where the optimal import capacity was below 1000 MW, and there were no investments in new resources. The wind scenarios reduce the optimal import capacity by about 60-150 MW depending on the scenario.

Table 3.14: Import capacity for each scenario.

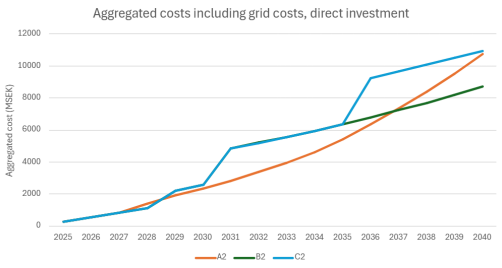
Scenario	Import capacity [MW]
D1	1052
D2	1073
D3	1074
D4	1126
$D1_w$	906
$D2_w$	1016
$D3_w$	973
$D4_w$	1047

3.2 Comparing import capacity

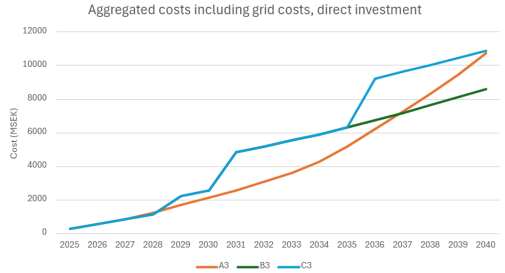
In this section are the costs associated with import capacity also included. Figure 3.22 shows the costs for the grid cases A, B and C with aggregated cost associated with the level of import capacity along with the capacity resources needed to meet the demand. The case B scenarios with a maximum of 1000 MW import results in the lowest cost in all the compared cases. Figure 3.23 shows the aggregated costs but with the investments of import capacity distributed over every year during their economic lifetime. The results shows that low import capacity will result in higher cost and that case B has a slightly less cost compared to case C.



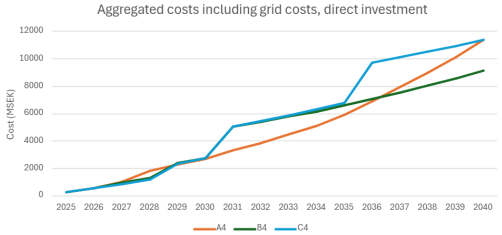
(a) A1, B1, C1



(b) A2, B2, C2

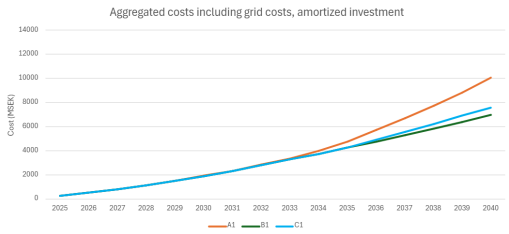


(c) A3, B3, C3

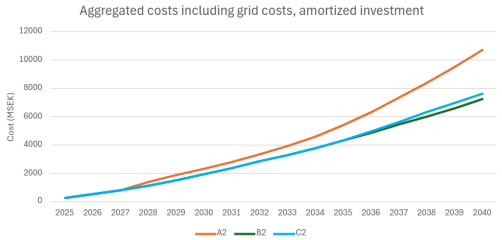


(d) A4, B4, C4

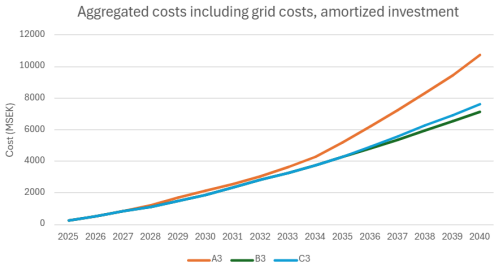
Figure 3.22: Aggregated cost every year for the whole system including direct grid investments.



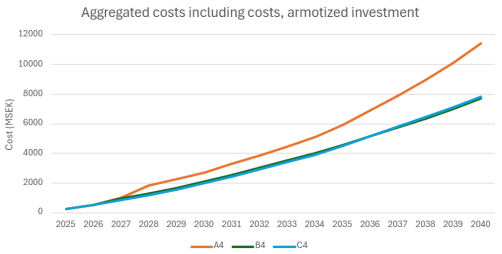
(a) A1, B1, C1



(b) A2, B2, C2



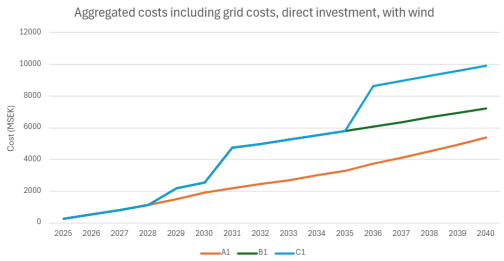
(c) A3, B3, C3



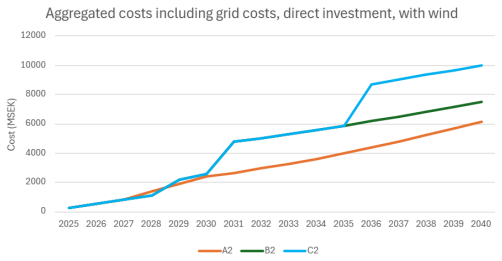
(d) A4, B4, C4

Figure 3.23: Aggregated cost every year for the whole system including amortized grid investments.

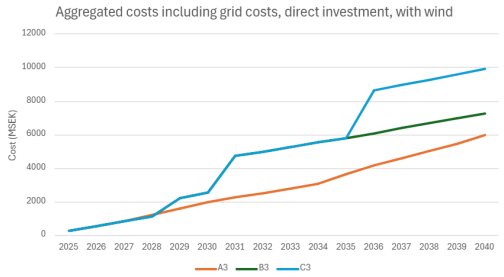
When including the wind park to the system the transfer fees decrease with about 850 MSEK over the time period from its installation in 2031 until 2040 for all cases. The impact of wind can be seen in figure 3.24. Case A is much more favorable as cost has reduced to almost a half compared to the corresponding no wind scenarios. However if the investments in import capacity is spread out over the investments lifetime it can be seen that this results in similar costs between the cases, see figure 3.25.



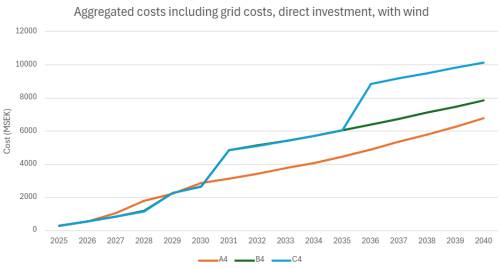
(a) $A1_w$, $B1_w$, $C1_w$



(b) $A2_w$, $B2_w$, $C2_w$

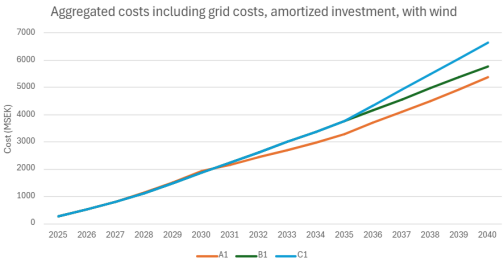


(c) $A3_w$, $B3_w$, $C3_w$

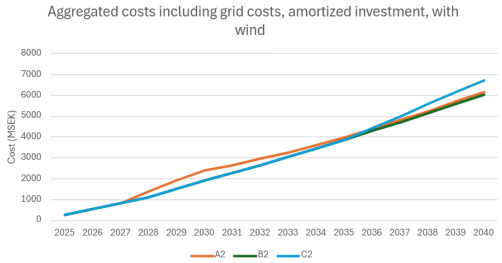


(d) $A4_w$, $B4_w$, $C4_w$

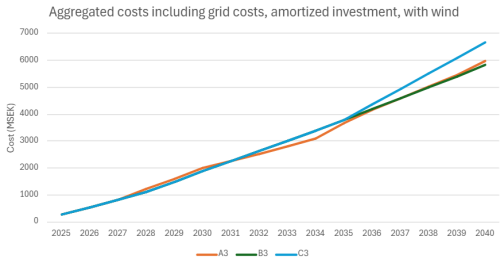
Figure 3.24: Aggregated cost every year for the system including direct import capacity investments, with wind.



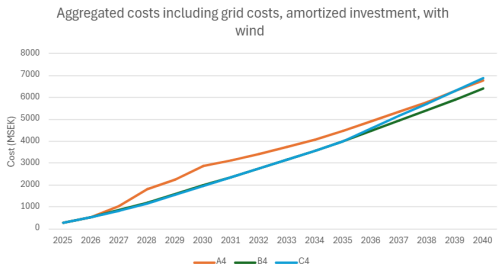
(a) $A1_w$, $B1_w$, $C1_w$



(b) $A2_w$, $B2_w$, $C2_w$



(c) $A3_w$, $B3_w$, $C3_w$



(d) $A4_w$, $B4_w$, $C4_w$

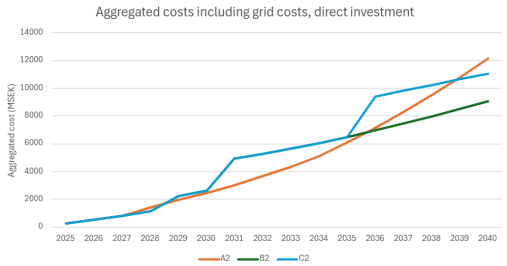
Figure 3.25: Aggregated cost every year for the system including import capacity investments amortized over lifetime, with wind.

Table 3.15 presents the annual cost for CHPs if they are to be compensated for the capacity they provide along with the yearly energy produced, without the wind park connected. There is a clear variation in the dependency on the CHPs across the three different import-levels. The total cost are 1409 MSEK for A2, 387 MSEK for

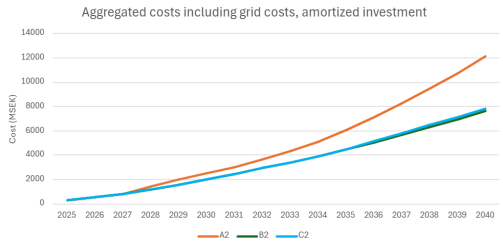
B2 and 152 MSEK for C2. The result of adding the cost of CHPs to the aggregated cost can be seen in figure 3.26. A2 which already was the most expensive solution increase even more in cost, while B2 is approaching the cost of C2, when amortizing the import capacity investment the cost of B2 and C2 will be similar. 3.27 shows the corresponding graphs but with wind included in the system. Figure 3.28 shows the cost of the scenarios if CHP is unavailable without wind.

Table 3.15: The annual summarized energy (MWh) provided by CHP for A2, B2 & C2 and annual reimbursement (MSEK/year).

	A2 MSEK	A2 MWh	B2 MSEK	B2 MWh	C2 MSEK	C2 MWh
2025	0,2	235	0,2	235	0,2	235
2026	0,8	1143	0,8	1143	0,8	1143
2027	4,4	6719	4,4	6719	4,4	6719
2028	17,2	26135	17,2	26135	17,2	26135
2029	52,5	79612	18,8	28560	18,8	28560
2030	65,7	99541	28,3	42817	28,3	42817
2031	77,1	116782	5,9	8898	5,9	8898
2032	92,4	139951	9,6	14504	9,6	14504
2033	104,6	158490	13,2	19946	13,2	19946
2034	120,1	182026	18,9	28653	18,9	28653
2035	147,3	223218	35,1	53225	35,1	53225
2036	132,1	200201	35,9	54320	0	0
2037	138,8	210259	40,7	61600	0	0
2038	144,8	219350	45,8	69371	0	0
2039	150,6	228219	51,1	77447	0	0
2040	160,5	243136	61,3	92834	0	0

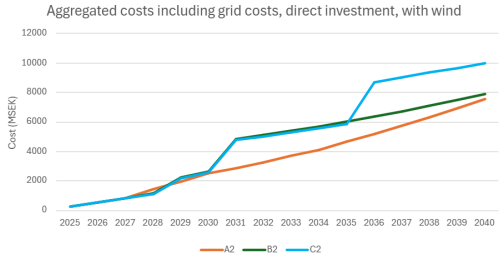


(a) Direct import capacity investment costs.

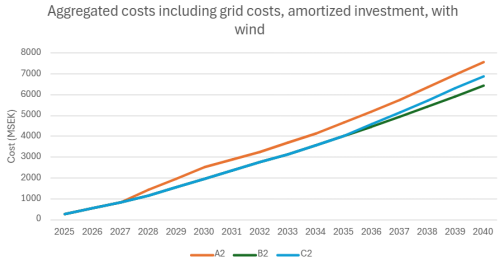


(b) Import capacity investment costs amortized.

Figure 3.26: Aggregated system cost including compensation for CHP in A2, B2 & C2.

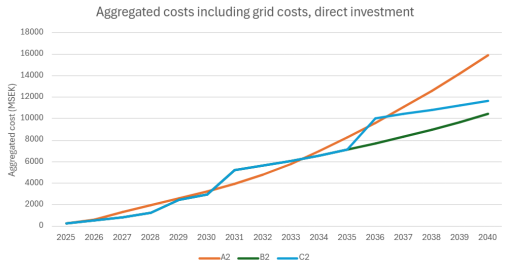


(a) Direct import capacity investment costs.

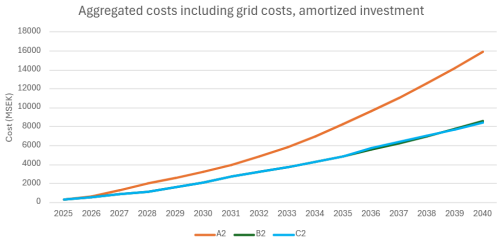


(b) Import capacity investment costs amortized.

Figure 3.27: Aggregated system cost including compensation for CHP in A2, B2 & C2 with wind.



(a) Direct import capacity investment costs.



(b) Import capacity investment costs amortized.

Figure 3.28: Aggregated system cost with no CHP available in A2, B2 & C2 without wind.

3.3 Sensitivity analysis

In order to perform sensitivity analysis on the parameters, one specific scenario was chosen as the most probable scenario. Which were selected to be C2, where the import capacity extensions are executed according to plan, flexible resources from other actors are available as projected and Rya is reimbursed on a quarterly basis.

The impact of solar was investigated by assuming that there were no increases to installed capacity of solar from 2023 throughout the time horizon. The impact on the cost of using local resources are shown in figure 3.29, as can be seen having less solar leads to a relative increased cost of using local resources of 14.8% relative to the base assumption.

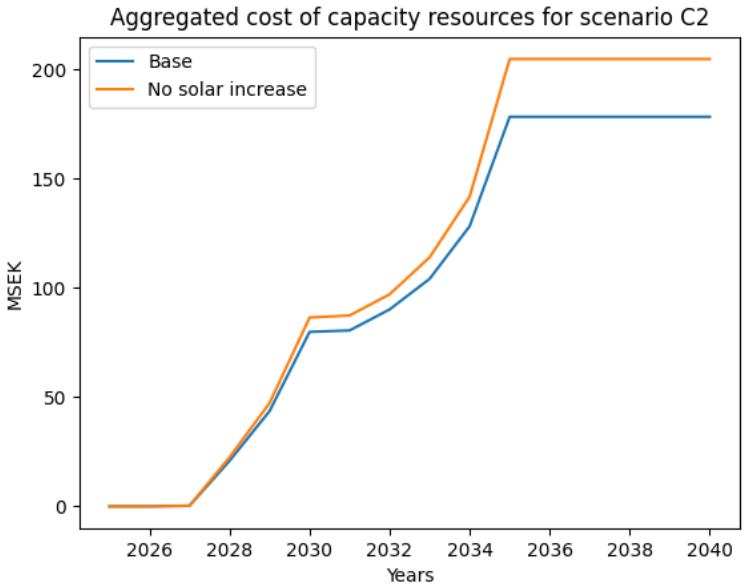


Figure 3.29: Cost of capacity resources with estimated increase of solar power and no increases of solar power.

In light of this, another simulation was conducted investigating the impact of no intermittent generation at all throughout the time horizon to investigate the sensitivity of intermittent resources contribution to capacity during deficiency hours, see Figure 3.30.

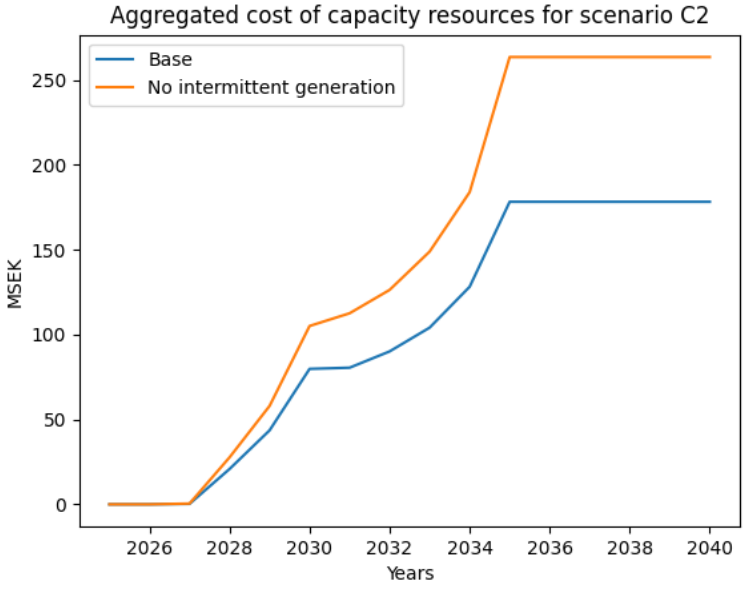


Figure 3.30: Cost of capacity resources with assumed generation of intermittent generators versus no intermittent generation.

With no intermittent power generation the cost to resolve the deficiencies for the

full time horizon increase significantly. Implying that the potential cost of capacity resources are likely higher, from either using capacity resources or reserving capacity to safe-guard from a drop in generation.

The impact of changes to cost of demand-side flexibility can be seen in figure 3.31. Increasing the cost to 3000 SEK/MW and 4000 SEK/MW per hour results in a total system cost increase of 2.7% and 3.6% respectively implying relative small impact on the total cost.

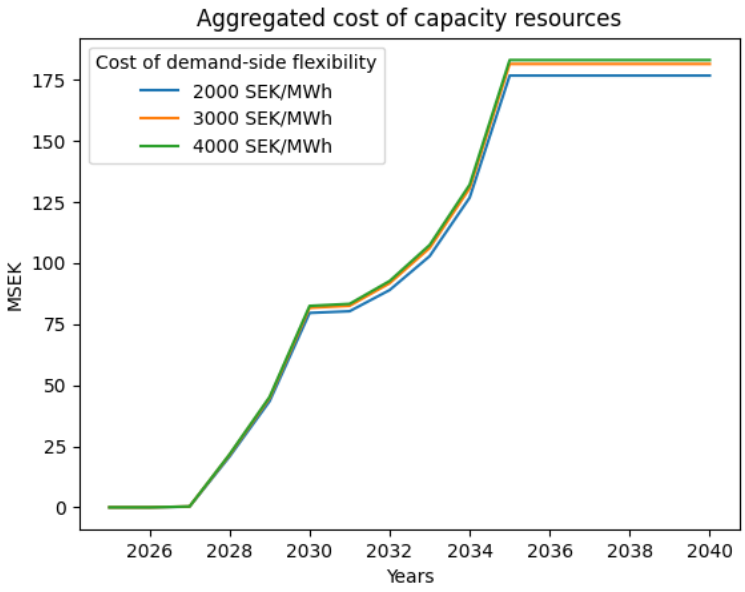


Figure 3.31: Aggregated cost of resources for different levels of cost for demand-side flexibility.

The impact of increases to biogas-price can be viewed in figure 3.32. Increasing biogas-price with 25% and 50% results in a system cost increase of 5.23% and 10.3%.

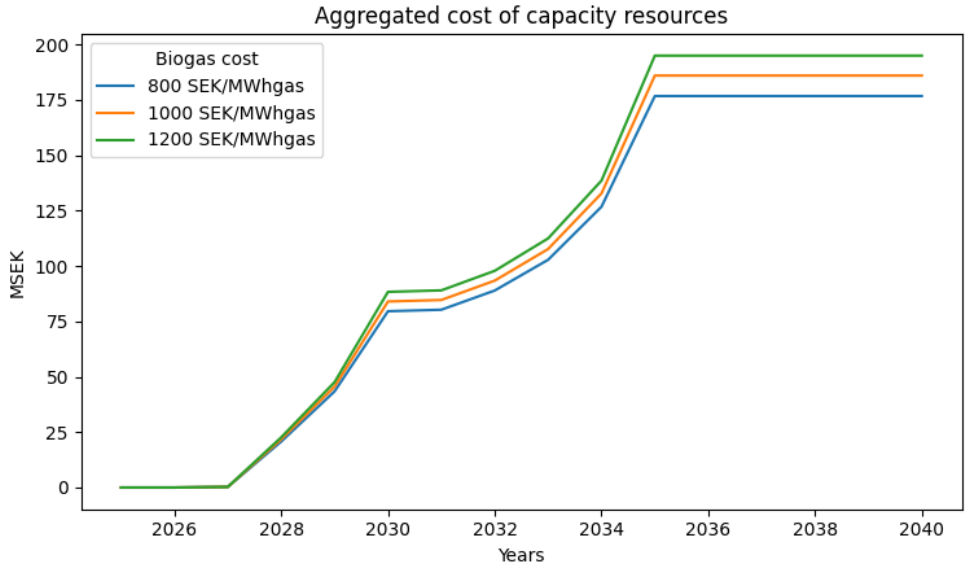


Figure 3.32: Resource cost comparison with different price of biogas.

Figure 3.33 shows the effect of a larger capacity of BESS locally. Suggesting potential savings for larger collective capacities of connected BESS OA.

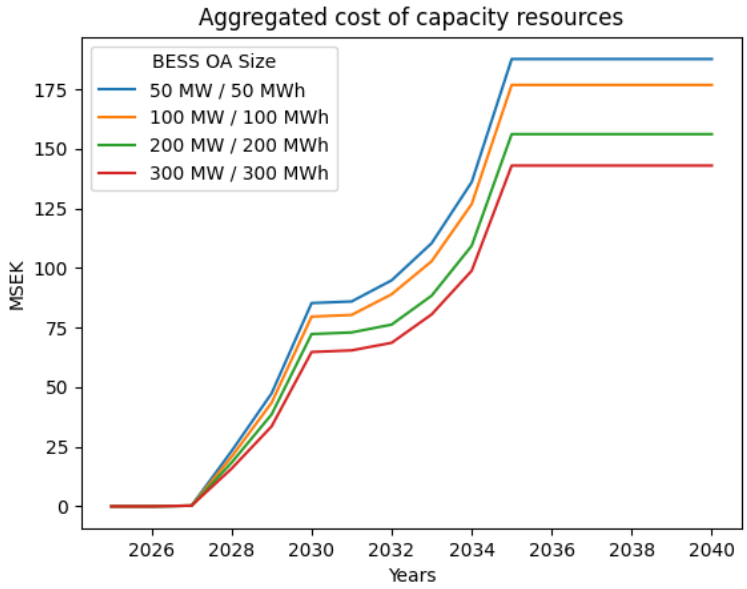


Figure 3.33: Resource cost comparison of different sizes of BESS OA.

4
Discussion

With many insecurities in the future energy system it was of interest to compare many different scenarios. Starting with the availability of flexible resources, being able to utilize the capacity of flexible resources from other actors have the biggest impact when Rya CCGT needs to be reserved on a quarterly basis, the total cost for case B and C with flexible resources available is about half, both with and without wind compared to the no flexibility scenarios. For case A the relative difference is smaller but the absolute difference is still significant.
The cost of capacity from energy storages were based on the Levelized Cost of Storage, as it gives a fair cost of the energy provided with a return on the investment. However this is sensitive to the input parameters used and a battery owner might be willing to participate to a different price than this depending on their operation strategy with regard to depth of discharge and other markets.
What is also not considered is the possibility that balancing markets or spot price arbitrage might passively assist the distribution grid by inciting resources to produce power during high demand hours. But it might be the other way around with actors participating on national balancing markets provides services that is counter-acting the local capacity demand.

There exists a risk in purchasing capacity from another actor that stems from the possibility that the resource will not deliver as contracted and Powercircle also highlights this in their report [40] by stating that contracts that regulates the risk and costs of insufficient deliveries from the resource are required. In practice there must be back-up capacity available to mitigate this risk and hence capacity would have to be reserved from another resource, for example from generators in Gothenburg such as Rya CCGT. Which would result in larger costs than the modeled results. The development of demand-side flexibility may differ from the one that has been assumed and used for the model, the local flexibility market Effekthandel Väst - Göteborg is still developing so no conclusion regarding future available flexibility may be drawn based on historic development. There may also be flexible resources within Gothenburg that differs in capacity, endurance and recovery compared to the ones that have been included in the model in this study. A more thorough mapping of potential local sources of demand-side flexibility is needed, both in terms of capacity and what level of compensation gives the optimal usage of flexibility.
Given the amount of active hours, especially for cases A and B in Table 3.4 and 3.8 along with the local flexibility market, it's reasonable that this will create an incentive for actors to chose Gothenburg to establish e.g. BESS. Though the active hours are fewer for the scenarios with wind, a large scale wind park could use stor-

age facilities to utilize more of the power produced and handle delivery variations. Hence, it's possible that large-scale BESS will continue to establish themselves in Gothenburg even though in this study it was assumed conservatively that there would be no increases past 2026.

The two different reservation lengths of Rya CCGT resulted in significant differences in the total cost of the system. For cases B and C the cost were almost doubled while for A the relative difference were lower. The short reservation is based on that the facility gets coverage from other markets to a larger degree, for example, grid balancing or readiness to be able to operate in island-mode. An example of this is Öresundsverket in Malmö that has been subsidized by SvK to be operable locally in the event of transmission system failure [41]. With longer reservations, a higher degree of fixed cost will be covered by capacity. The portion that is not reserved is assumed to be able to be used for other purposes such as balancing. The quarterly reservations means that preparedness is payed by capacity on a seasonal basis. There are also uncertainties regarding what minimum level of capacity that Rya CCGT would be willing to be reserved, if Rya is used in combination with other purposes and costs are shared this could be beneficial to several actors. In the A-scenarios the reservation levels is high, but it's not reserved for a full year. In the B and C-cases the reservation levels are lower and less of the plants capacity is used, leading to lower coverage of the plants costs. Resulting in that the plant must cover its costs on other markets to a larger degree. Connecting the wind park resulted in a dramatic decrease in cost for capacity resources for the low import capacity case, which became less significant with higher import capacity cases. However the reservation level of Rya CCGT were almost not changed at all. With the same reservation are the same fixed cost and capital costs compensated towards Rya but the operational costs becomes lower, this indicates that the combination of having a high degree of intermittent production and paying dispatchable production sites to be prepared to produce power when the production from wind is low could be a cost effective solution compared to import capacity investments.
One of the challenges of the future energy system in terms of local capacity is the uncertainty of what units will be producing power during peak demand hours. In Gothenburg this is the case for the combined heat and power plants. In the base scenarios it was assumed that power is produced from the CHPs since high demand hours in general occur when there is a high heat demand and high electricity prices making it profitable. However, this might not be the case and the resource must either be compensated as a capacity resource or might not even be available to produce power at all. Without the assumed electricity production from CHPs the system must create about 70 MW of extra capacity, in A and B this means investments in new gas turbines and in C a higher degree of reservation of Rya CCGT.

Figure 3.22 and 3.23 compared the costs of all scenarios including grid costs. Case A is not favorable in any scenarios when the investment cost is amortized since it resulted in the highest cost. The results show that B is slightly more cost efficient but not with a wide margin. If the demand continues to increase past 2040 the cost of capacity resources will likely outweigh the costs of import capacity.

When connecting the wind-park it can be seen in Figure 3.24 and 3.25 that case

A becomes much more cost effective in relation to the other import capacity levels. With much more power production in the local grid, reserving Rya CCGT and investing in new gas turbines becomes competitive with investments in import capacity. However, when compensating or removing the production from CHPs, the A-scenario will become less favorable both with and without wind.

The results shows in general that the case B import level is more favorable than C in terms of cost, this is also partly supported by the results of the D-scenarios where the cost-optimal import level on average is closer to 1000 MW than 1250 MW, seen in Table 3.14. This means that one can argue that local investments of capacity can be more suitable to a certain degree. It also comes with the benefits of a electricity system with a stronger self-sufficiency where a city can uphold a larger degree of capacity without being dependent on the rest of the transmission system. One downside is that a local system with lower import capacity is more dependent on fewer resources and that they are producing power as intended, in Figure 3.28 it can be seen that removing the assumed base production from the CHPs the cost of scenario B2 approaches the cost of C2.

The results of this project can be seen as a basis for discussion regarding the possibilities to shift some of the focus of investments in grid capacity towards investments in local capacity.

5
Conclusion

This study investigates the value and cost of capacity in Gothenburg. The results highlights the following conclusions:

- Rya CCGT is an incredibly important resource to provide capacity during longer periods of high load. With more local intermittent power production, the plant can operate as a back-up resource. This is under the assumption that the reservation level is sufficiently covering the costs or excess capacity can be used on other markets. Full, yearly coverage for the facility allocated to providing capacity could make it more beneficial to invest in new gas turbines that are dimensioned for the required capacity. However, further investigations are required into how procurement of capacity from Rya CCGT should be done.
- Utilizing flexible resources of other actors can result in significant cost savings over the time period depending on the scenario.
- The results are highly dependent on what assumptions are made for the future energy system both in terms of availability and cost models. With large capacity of cheap local production available with high reliability can small grid capacity levels with investments in local plannable and flexible compete with extending grids cost wise. A grid level of at least 1000 MW is however recommended considering all uncertainties in the future system.
- When the investment cost of import capacity is amortized there is a relative small difference in the cost between case B and C. The case D results imply that an import capacity in the range of 1000-1100 MW is sufficient by 2040, however the scale of the import capacity between 1000 to 1250 MW has to be investigated in further detail
- Local renewable resources can make a significant difference for lower import capacity levels. However, with increased capacity of 1250 MW in 2036 the addition of a 1000 MW wind park to the local grid will not be of any significant help in capacity terms.
- Power production from the combined heat and power plants is valuable to avoid using capacity resources with a higher running cost. Even with compensation for power production the overall system cost will be significantly lower compared to without the assumed base production from these units.

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A

Appendix 1

Table A.1: Assumed increase of residential batteries throughout the time horizon.

year	Storage capacity (MWh)
2025	30
2026	34,9
2027	38,4
2028	42,4
2029	46,5
2030	50,5
2031	54,6
2032	58,6
2033	62,6
2034	66,7
2035	70,7
2036	74,8
2037	78,8
2038	82,9
2039	86,9
2040	91

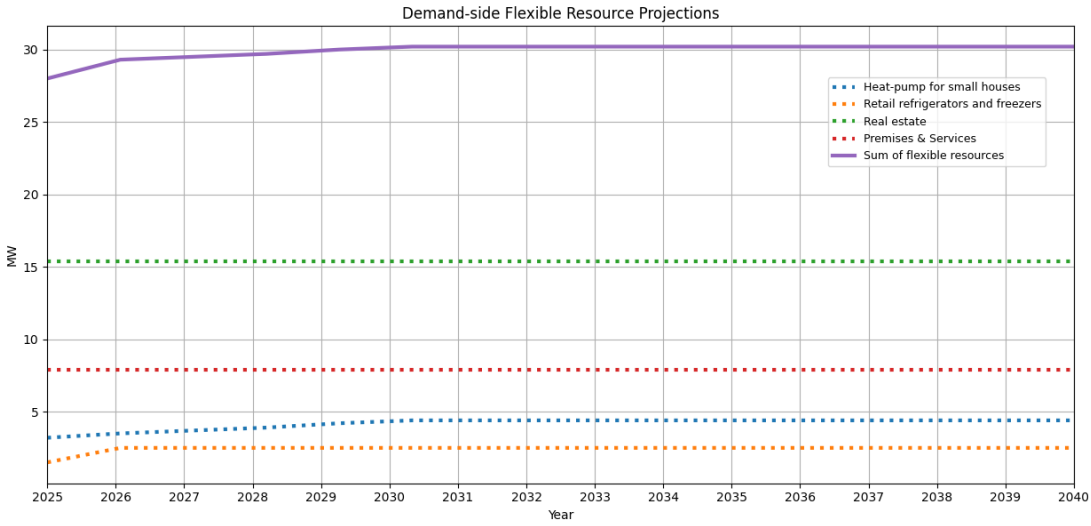

Figure A.1: Projection of potential capacity per demand-side flexibility segment, per year.

Table A.2: Available capacity of V2G per year.

Year	V2G capacity (MWh/h)
2025	0,838
2026	2,34
2027	4,52
2028	7,37
2029	10,9
2030	15,1
2031	20,9
2032	28,5
2033	37,7
2034	48,6
2035	61,2
2036	75,4
2037	91,3
2038	109
2039	128
2040	154

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