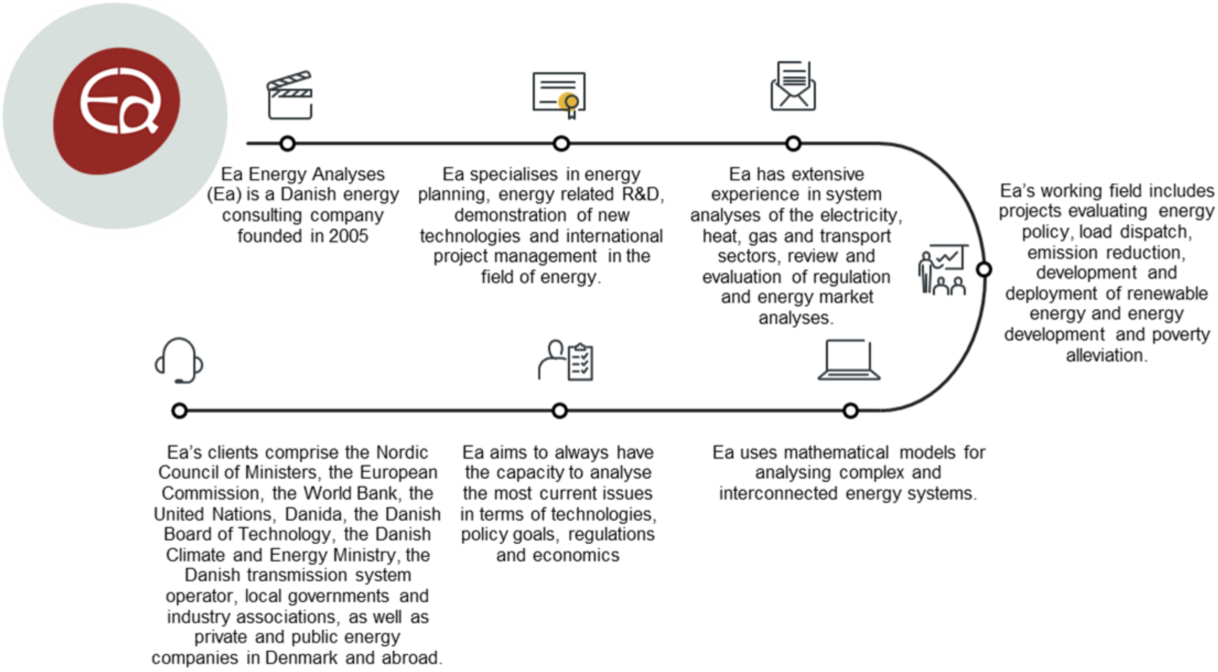
Power outlook and security of supply in Region Skåne

April 2021



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Contents

1 Introduction

The Skåne region with a population of over 1.3 million, is the southernmost county of Sweden. It is made up of 33 municipalities with Malmö, Helsingborg and Lund being the largest by population. In the Nord Pool power market, Sweden has four bidding areas and Skåne is part of the SE4 region. Historically, the region has seen higher electricity prices as compared to other parts of Sweden.

The desire for more climate-friendly electricity production and the expansion with PV and wind turbines challenges the economic conditions for thermal power plants. This has also been the case in Skåne, where among others the relatively new Öresund plant was closed down in 2017 due to low electricity prices and increased competition in the market for district heating. In Skåne (and electricity price area SE4 in general), the reduction in thermal production capacity has presented challenges for the electricity grid. In Skåne, some stakeholders talk about a lack of production capacity, “effektbrist”, which is temporary though and is expected to be resolved when the main grid is strengthened in 2024. Until then, Heleneholmsverket in Malmö will function as a capacity reserve and in addition a new local pilot market for capacity, called Switch, has been established.

Furthermore, the lack of available thermal production capacity in the electricity market of Southern Sweden meant that Svenska Kraftnät, in the summer of 2020, found it necessary to make financial arrangements with Ringhals nuclear power plants (881 MW), Uniper's Karlshamnsverket (310 MW) and Göteborg Energi's Rya CHP plant (170 MW) to provide reactive power and some cases also active power.

In Zealand - which is closely connected to the power system of Southern Sweden - Energinet also sees potential challenges to the security of supply and considers purchasing a strategic reserve to handle the situation.
The purpose of the project has been to shed light on the economic conditions for power generators in Southern Sweden and the related challenges for the security of electricity supply.

Reading guide

Chapter 2 provides a short overview of the current power supply in Skåne and SE4 building on public sources and data.

Chapter 3 explores different pathways for the development of the power sector in SE4. The analyses are based on power market analyses with the energy system model Balmorel assessing among others the future capacity balance in the region and wholesale power prices. Because SE4 is well interconnected with neighbouring regions the geographic scope of the modelling is North and Central Europe.

Chapter 4 looks at the economic conditions for existing and new thermal power generators using the power price projections from chapter 3. Revenues are determined in the spot and regulating power markets.

Chapter 5 presents conclusion and recommendations that follow from the analyses.

2 Diagnosis and mapping

Skåne region is a part of the SE4 bidding zone along with Kronoberg, Blekinge and Öland regions and parts of Kalmar, Jönköping and Halland regions, shown in Figure 1.

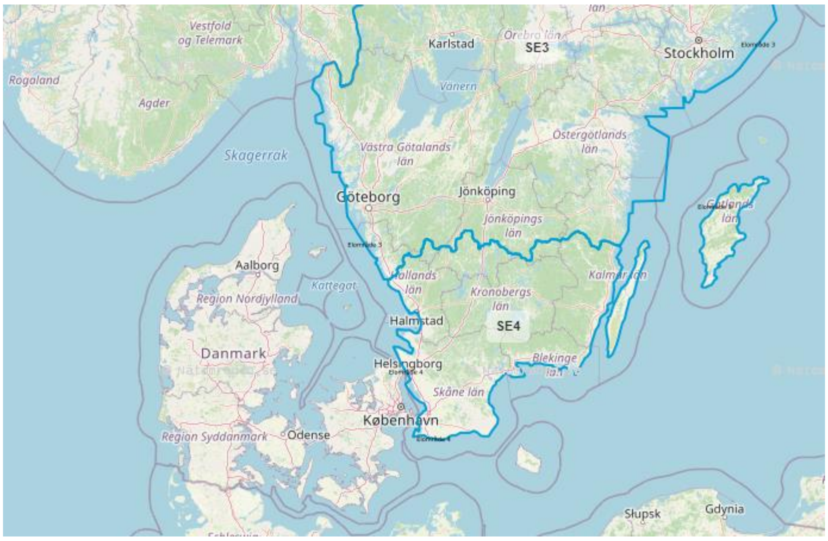


Figure 1: The regions of the SE4 bidding zone.

Historically, the electricity consumption in SE4 has been mainly covered by import from neighboring regions, especially SE3, as shown in Figure 2. Thermal generation have been steadily declining since 2015 reaching 0.8 TWh in 2019. Generation from onshore turbines has been increasing, reaching 4.2 TWh in 2019.

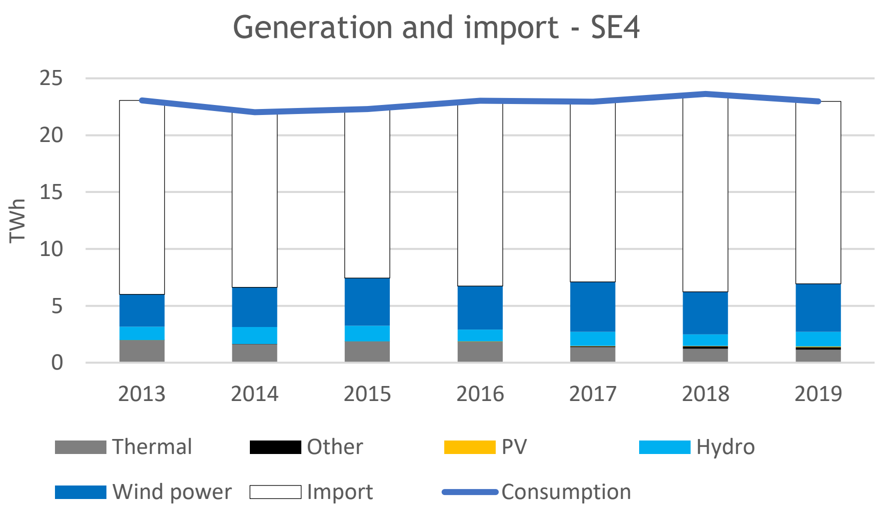


Figure 2: Generation and import of electricity in SE4 between 2013 and 2019.

The SE4 bidding zone contains many small-scale thermal generators, mainly combined heat and power units (CHP). However, the sum of the capacity these thermal generators is 1.5 GW, which is significantly smaller than the peak demand of 5 GW in the bidding zone. The current capacity balance is shown in Figure 3.

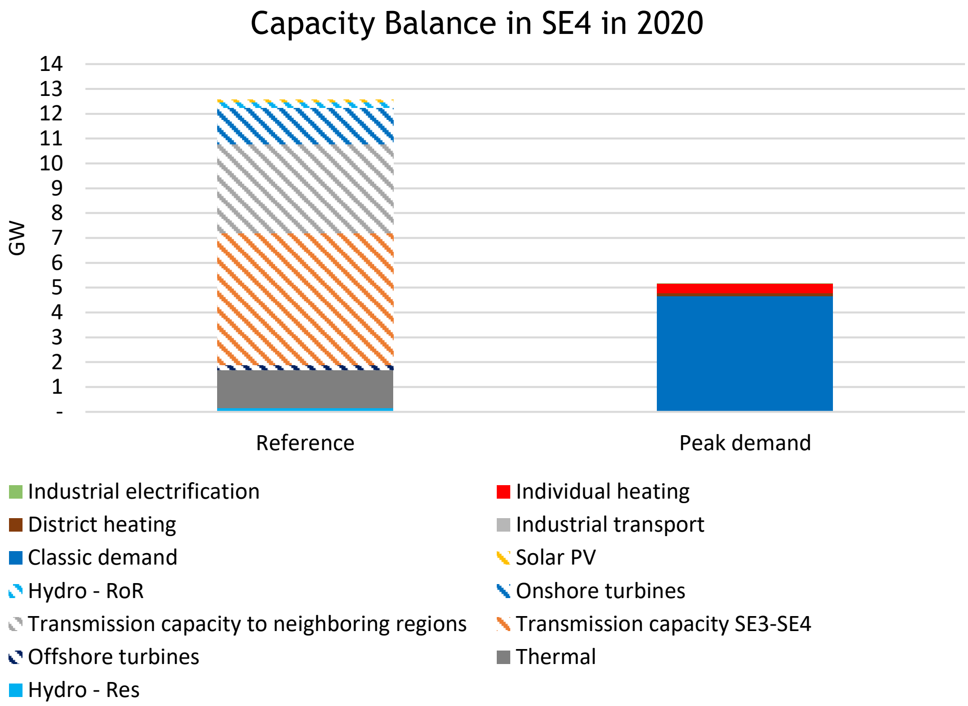


Figure 3: Capacity balance of SE4 in 2020.

The capacity balance shows the peak demand, dispatchable capacity and transmission capacity to neighboring regions. The SE4 bidding zone is reasonably well connected to neighboring regions with 5.3 GW from SE3 and 3.6 GW from other regions such as DK2, Germany, Poland and Lithuania. This means that peak demand can potentially be supplied by neighboring regions alone if cross border transmission capacity is available. During March and April 2021, the available capacity for the spot market between SE3 and SE4 has however only been at around 4 GW and the capacity of other interconnectors are also sometimes limited as it appears from the figures on the next page.

Note that looking at the capacity balance is one issue, but frequency and voltage control is another issue completely. Other tools such as PowerFactory and PSS/E is needed to evaluate the frequency and voltage stability of a grid.

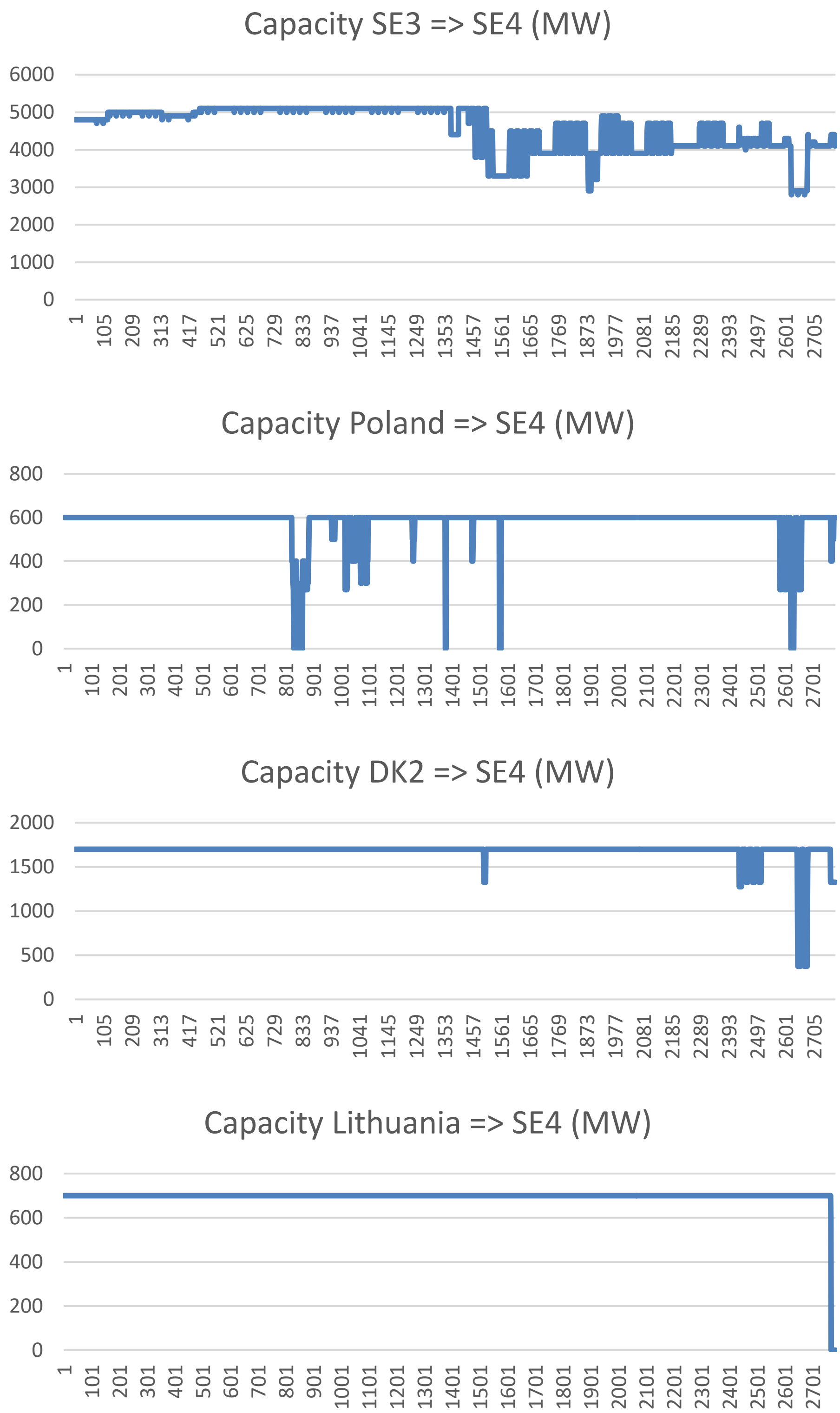


Figure 4: Elspot capacity from neigbouring regions to SE4 during 2021 (1. Jan – 26 April) Hourly resolution. Source: NordPool

3 Outlook and Power Market Analysis

This section provides information on how the power system in SE4 and neighboring jurisdictions is projected to develop towards 2040 and what opportunities lie ahead. The capacity balance of the future energy system is analyzed as an indicator for security of supply.

Moreover, we explore how power prices in the SE4 region can expect to develop as input for the business case analyses of thermal power generators in the following chapter.

The Balmorel power market model is applied for this part of the study.

3.1 The Balmorel model

The Balmorel model is a bottom-up energy system model used for modelling and simulating power and district heating markets. The model optimizes the generation dispatch, transmission and consumption of power and heat under the assumption of full foresight. Balmorel can be applied for policy analysis and testing future scenarios. The spatial resolution in Balmorel can cover any country or geographical area. For this project, the spatial resolution covers the Nordic countries and countries that are of importance to the Nordic power system. These are Austria, Belgium, Czech Republic, Estonia, France, Germany, Great Britain, Latvia, Lithuania, Luxembourg, Netherlands, Poland, Italy and Switzerland, as shown in Figure 5.

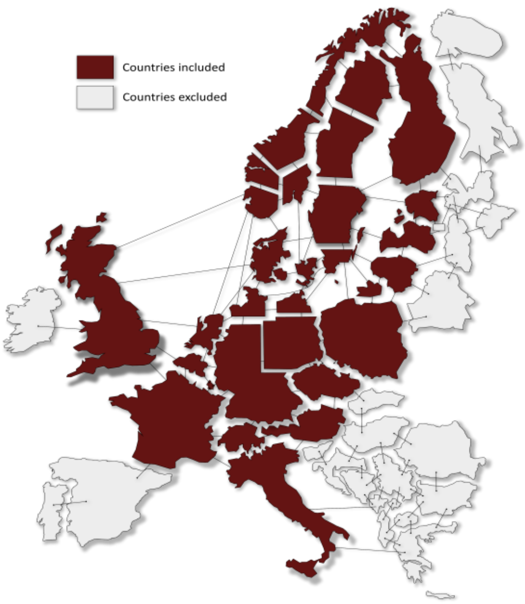


Figure 5 The modelled area in Balmorel.

The model assumes perfect market conditions where units bid in the power market according to their short-term marginal costs, corresponding to a merit order curve approach. It operates iteratively in two steps which is investment optimization and then a unit dispatch optimization. Further documentation of the Balmorel model is presented in Appendix 6.1.

A detailed representation of offshore areas in the Baltic Sea and North Sea, as shown in Figure 6, are also a part of the model. These areas are created based on data from potential sites for offshore turbines. The model has the option to apply capacity in these areas. Additionally, it has the flexibility to connect multiple neighbouring regions to an offshore area.

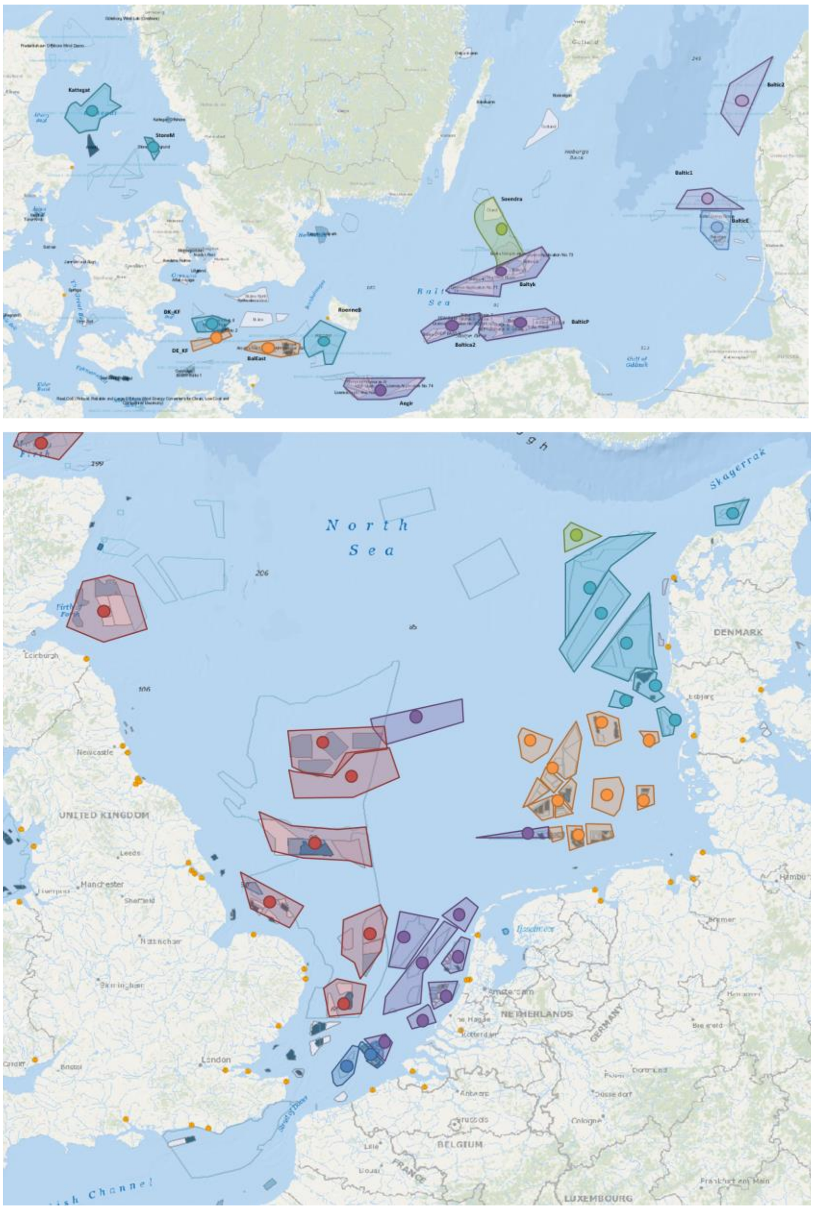


Figure 6 Baltic Sea and North Sea offshore areas in the Balmorel model.

3.2 Scenarios for the future development of the power sector

One reference scenario and three sensitivity scenarios have been developed for the power market analysis. These are further explained here:

1. The **reference** projection assumes that European countries act on their climate targets and achieve almost total decarbonization of the power system towards 2050. This decarbonization is driven by an increasing cost of CO_2-emissions allowances, along with further cost reductions of wind power and solar PV. The forecast of electricity demand is based on the European Commission's 2050 Long-Term Strategy, 2018 (LTS18)[1], following the so-called COMBO[2] scenario in 2050, which shows roughly 90% GHG reductions in 2050 at the EU level. The reference projects increased electrification of the transport, heating, and industrial sector along with clean fuels such as hydrogen as a main strategy to transform and store energy. The total electricity demand in the COMBO scenario increases by about 90% between 2020 and 2050 and almost 70% of the power demand increase stems from the production of electrofuels, such as hydrogen and ammonia, at Power-to-X (PtX) plants.
2. Four different sensitivity analyses.

- **High demand scenario** – The future electricity consumption of the Swedish industry is a debated topic as of 2021. Luossavaara-Kiirunavaara Aktiebolag (LKAB) has announced ambitious electrification plans of the mining industry which could lead to 55 TWh higher electricity consumption in 2045. This is reflected in the high demand scenario which sees a gradual increase of electricity consumption in Northern Sweden which reaches over 50 TWh in 2040.
- **NIMBY - scenario** – The not-in-my-back-yard scenario represents a scenario where solar PV and onshore wind developments are limited in the model area, except for Sweden. The leads to a stronger deployment of offshore wind.

[1] A Clean Planet for all - A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy https://ec.europa.eu/clima/policies/strategies/2050_en
[2]The COMBO scenario is a combination of 5 long term strategy options called Electrification (ELEC), Hydrogen (H2), Power-t o-X (P2X), Energy Efficiency (EE) and Circular Economy (CIRC).

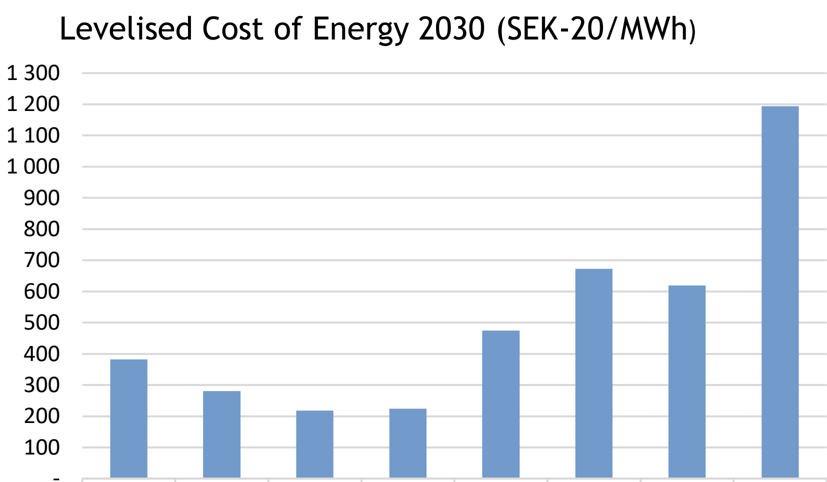
- **Delayed electrification** – The delayed electrification scenario reflects a case where the increasing electricity demand for PtX fuels is delayed. The scenario contains no PtX electricity demand in the model area.
- **Thermal sensitivity** – the reference scenario assumes that there is refurbishment of thermal generators in Sweden. However, this thermal sensitivity investigates a case where the model has to choose between refurbishment and decommissioning of thermal capacity at end of life.

3.3 Main assumptions

This section presents the main assumptions applied for the power market analysis, i.e., electricity demand projections, fuel- and CO_2 prices as well as local capacity development and capacity potentials for different types of generators for Sweden.

3.3.1 Technology development for new plants

The assumed development of data for each generation technology is based largely on the Danish Energy Agency's Technology Catalogue. The 2030 LCOE of some selected generation technologies are shown in Figure 7.



	Offshore turbines	Onshore turbines	PV - utility scale	PV - utility scale + tracker	PV - medium scale	PV - small scale	CC gasturbine	600 MW biomass CHP
Total costs	382	281	218	224	475	673	619	1 194

Figure 7: LCOE's for new power generation capacity based on the DEA Technology Catalogue.

3.3.2 Development in electricity consumption

As previously mentioned, demand projections are based on the European Commission's 2050 Long-Term Strategy, 2018 (LTS18), following the COMBO scenario until 2050, which shows roughly 90% GHG reductions by 2050. While the total demand in the COMBO scenario increases by 90%, between 2020 and 2050, it does not project very high levels of direct electrification of the transport, heating, and industrial sector. Rather, the COMBO scenario sees clean fuels such as hydrogen as the main strategy to transform and store energy. Following the importance of clean fuels in the COMBO scenario, almost 70% of the power demand increase (2020-2050) stems from PtX. Increased levels of direct electrification and subsequently lower levels of indirect electrification (PtX) will lead to a lower total electricity demand due to higher efficiency of direct electrification. Figure 8 shows the projected development of electricity consumption in the modelled area. PtX electricity consumption is projected to be the main source of electricity consumption increase in 2040. Further category descriptions are presented in Appendix 6.2

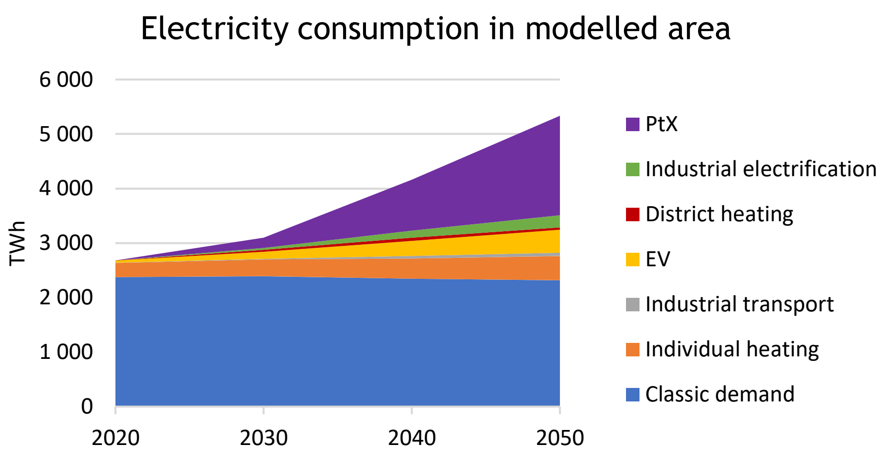


Figure 8 Projected electricity consumption in the modelled area.

The electricity consumption in Sweden is also projected to rise mainly due to increases in PtX electricity consumption. The reference projection of consumption applied in this project reaches 180 TWh in 2040, shown in Figure 9. However, it is possible that the electricity consumption will increase even further because of electrification of heavy industries and global industries moving manufacturing to Northern Sweden where the power prices are comparatively lower. This possibility will be investigated through sensitivity analysis and is explained later.

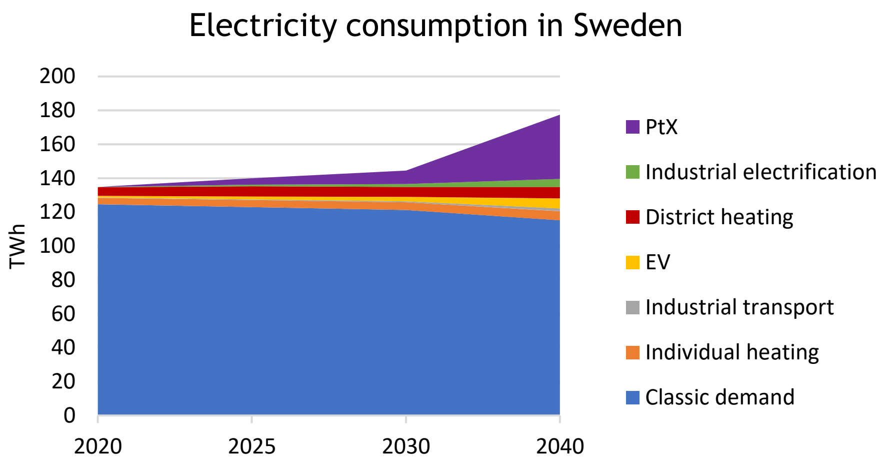


Figure 9: Projected electricity consumption in Sweden.

The projected electricity consumption in SE4 is shown in Figure 10. The main increase in consumption is due to PtX similar to that expected for Sweden as a whole. The relative increase in total electricity consumption in SE4 is 21 percent from 2020 to 2040 which is lower than the 31 percent increase in total Swedish consumption. This is mainly due to the greater likelihood of PtX electricity consumption being placed in SE1, SE2 and SE3. The electric vehicle (EV) electricity consumption in SE4 is projected to be 0.6 TWh in 2030, equivalent to 240,000 EV’s, and 1.3 TWh in 2040, equivalent to 510,000 EV’s, assuming a yearly consumption of 2,580 kWh per vehicle.

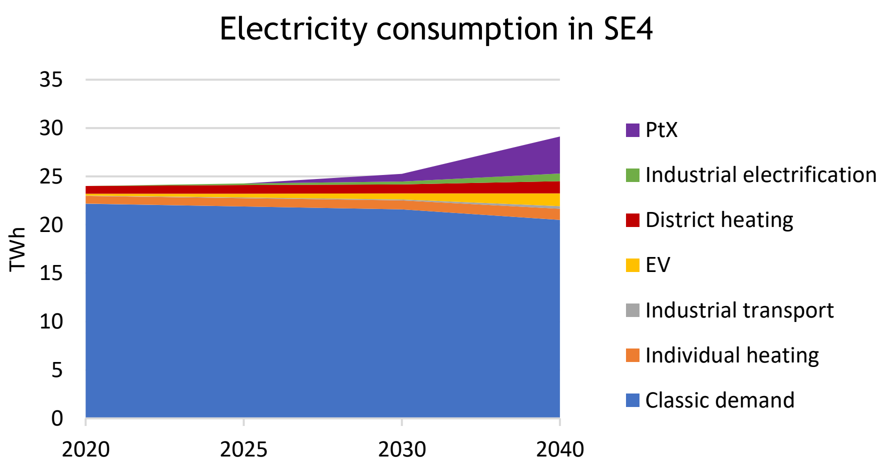


Figure 10: Projected electricity consumption in SE4.

3.3.3 Fuel- and CO_2 prices

Fuel prices

Fossil fuel prices are based on the Sustainable Development Scenario from International Energy Agency’s World Energy Outlook 2020. The prices are taken for 2030 and 2040, and extrapolated hereafter. For 2021, forward prices, which is a predetermined price of a commodity between buyers and sellers, are used. Between 2021 and 2030 prices are projected to converge from forward prices to the IEA projections.

Historically, the IEA has underestimated technological progress. Choosing the Stated Policies Scenario could potentially lead to the underestimating the cost competitiveness of RE technologies, and therefore leading to higher fuel price estimates. Furthermore, the Paris Agreement and European Green Deal strengthen the argument for using the sustainable development scenario. The applied fuel price projections are shown in Figure 11.

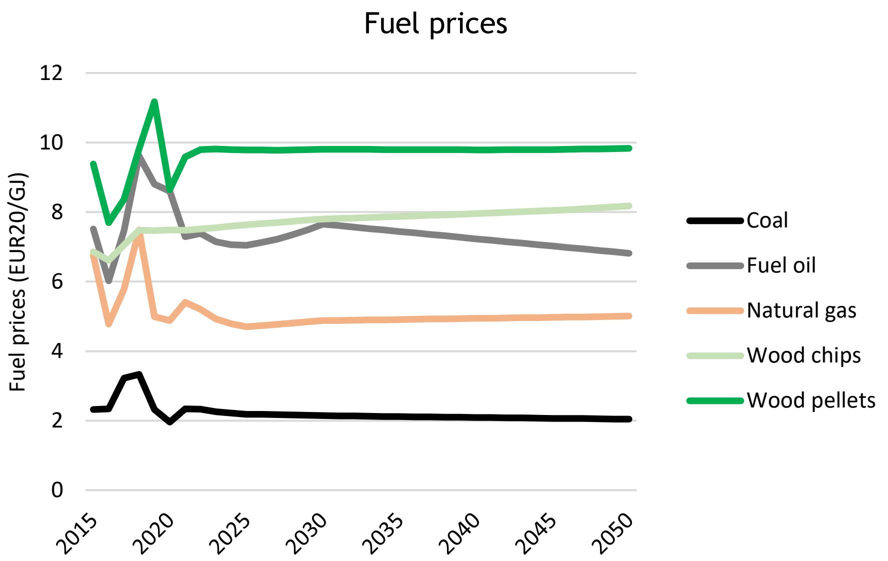


Figure 11: Fuel prices applied in the model.

CO₂-prices

The price of CO_2 emission rights has increased from approximately 5 €/ton in 2017, to 44 €/ton in April 2021. Based on the analyses underlying the European Commission's impact assessment for a 55 % GHG reduction target in 2030, it is anticipated that the CO_2-price will remain at the same level until 2030. A higher reliance on the ETS system to fulfil climate targets, reflected in the EU Commission's so-called CPRICE scenario, may increase the CO_2-prices. In the long term, the CO_2 price is assumed to grow rapidly reaching 120 €/ton, equal to the level in the IEA WEO Sustainable Development Scenario. The applied CO_2 price projection is shown in Figure 12.

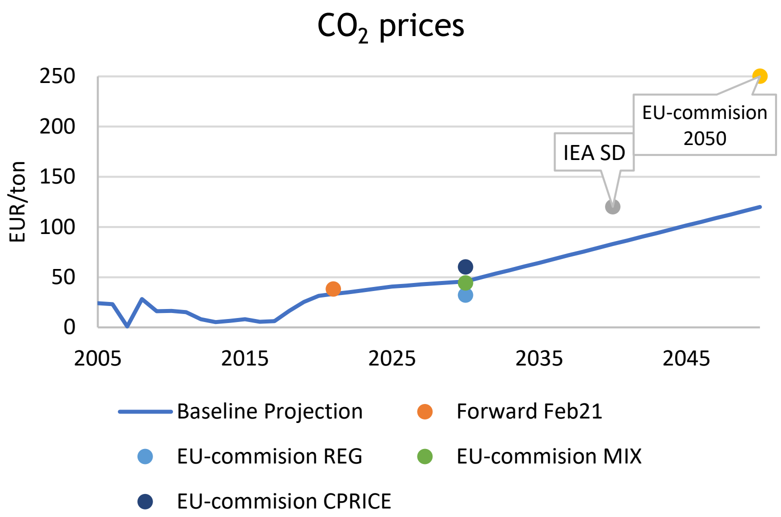


Figure 12 CO_2 price projection applied in the model.

Taxation of district heating production from natural gas

There is a 93.3 SEK (9.2 EUR) per GJ tax on district heating production from natural gas units in Sweden. This is not included in the Balmorel model as well as other Swedish specific taxation schemes, for example on heat from electricity that is not accounted for either. However, this taxation of district heating from gas is included in the generator specific economic analysis in chapter 4.

3.3.4 Specific assumptions for Sweden

Thermal capacity

In their short-term market analysis called "*En sammanfattning av Kortsiktig marknadsanalys 2020*" Svenska kraftnät (Svk) projects that Karlshamnsverket in Blekinge and Heleneholmsverket in Malmö are decommissioned by 2025. This assumption is included in the model. Table 1 shows an overview of thermal capacity, both backpressure and condensing, per region in Sweden.

Table 1 Thermal capacity per region in Sweden. Source: Svenska kraftnät

Thermal capacity (MW)	2021	2022	2023	2024	2025
Sweden	**5,660**	**5,660**	**5,700**	**5,730**	**4,960**
- SE1	290	290	290	290	290
- SE2	760	760	760	760	760
- SE3	3,100	3,100	3,140	3,160	3,160
- SE4	1,510	1,510	1,510	1,510	750

The thermal capacities are assumed to be refurbished at end of life to maintain capacity in the system towards 2040.

Nuclear capacity

There is uncertainty regarding the nuclear capacity present in the Swedish power system. All existing nuclear power plants are assumed to online with for the time horizon of this study, 2020-2040.

There is some probability that these nuclear reactors will be decommissioned in the future. However, the increasing need for baseload capacity may make these reactors more than likely to be profitable for another 20-year life extension. This project assumes that all reactors be decommissioned at the end of their 60-year lifetime which is between end-2040 and 2050, shown in Table 2. The discussion on the future of nuclear does not affect the modelling in this study.

Table 2 Assumed nuclear decommissioning dates.

Name	Unit No.	Reactor Type	Capacity in MW Net	Commercial operation	Closure Date
Forsmark	1	BWR	986	10 Dec. 1980	10 Dec. 2040
Forsmark	2	BWR	1,116	7 Jul. 1981	7 Jul. 2041
Forsmark	3	BWR	1,167	18 Aug. 1985	18 Aug. 2045
Oskarshamn	3	BWR	1,400	15 Aug. 1985	15 Aug. 2045
Ringhals	3	PWR	1,062	9 Sep. 1981	9 Sep. 2041
Ringhals	4	PWR	1,104	21 Nov. 1983	21 Nov. 2043

Onshore wind turbine potential

Svensk Vindenergi projects a significant short-term build-out of onshore turbine capacity towards 2025. The increase in onshore turbine capacity from 2020 to 2025 is projected to be around 7 GW, shown in Figure 13. This projected development is included in the model.

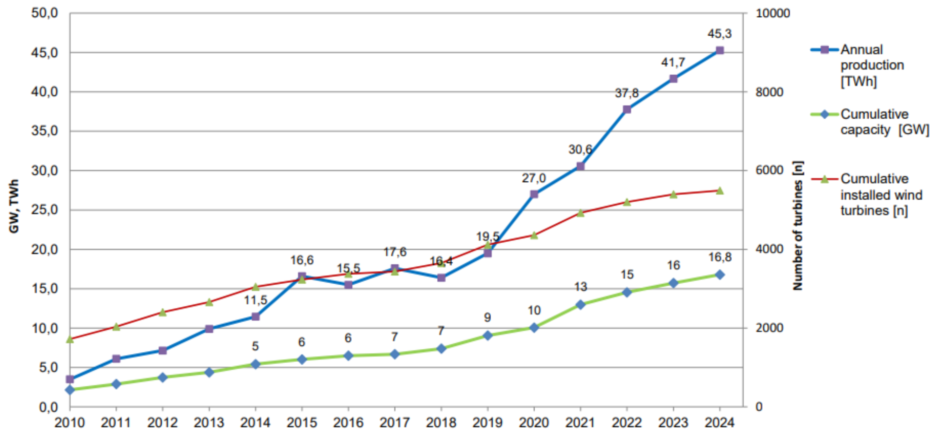


Figure 13 Projected onshore turbine capacity and generation development. Source: Svensk Vindenergi.

From 2025 to 2040, a maximum potential of 30 GW for onshore wind potential in Sweden is considered, based on data from Energimyndigheten's (2021) "Nationell strategi för en hållbar vindkraftsutbyggnad". This is reflected in the maximum onshore wind potential in 2030 that is set at 25 GW and 30 GW in 2040 as shown in Table 3.

Table 3 Onshore potentials in Sweden per region.

Onshore turbine potentials (MW)	SE1	SE2	SE3	SE4	Total
2025	2,076	5,190	8,131	1,903	17,300
2030	3,000	7,500	11,750	2,750	25,000
2040	3,600	9,000	14,100	3,300	30,000

Reserve requirements

The Balmorel model contains a requirement of 1,960 MW of strategic and manual reserve for Sweden to be supplied by generations units. This requirement is defined on a country level. For comparison, today, Svenska Kräftnet has a total requirement of 2,700 MW of reserves (700 MW of fast reserves with an activation time less than 2 minutes, 1450 MW of capacity with an activation time less than 15 minutes, i.e. störningsreserven, and 562 MW of strategic reserves), which can be provided by production and consumption units.

District heating consumption

District heating production data has been gathered locally from each municipality in Skåne to model the district heating demand of the region, as shown in Table 4.

Table 4 District heating demand of each municipality in Skåne.

Municipality	District heating production (GWh)	Municipality	District heating production (GWh)
Bjuv	21.0	Perstorp	44.9
Bromölla	34.3	Simrishamn	46.1
Eslöv-Lund-Lomma	805.0	Skurup	27.1
Helsingborg	958.4	Staffanstorp	25.5
Hässleholm	173.8	Trelleborg	90.1
Höganäs	41.5	Ystad	128.6
Kristianstad	340.6	Ängelholm	161.5
Landskrona	247.2	Örkelljunga	26.4
Malmö	1971.0	Åstorp	37.8
Total			**5181**

3.4 Development in the European power system in reference

The transition toward renewable energy sources is driven by increasing CO_2 prices that increase generator marginal costs. A transition to renewable energy sources unfolds throughout the model area as PV, onshore and offshore wind generation increase towards 2040. The renewable energy shares of the model area reach 50% in 2030 and 74% in 2040 as shown in Figure 14.

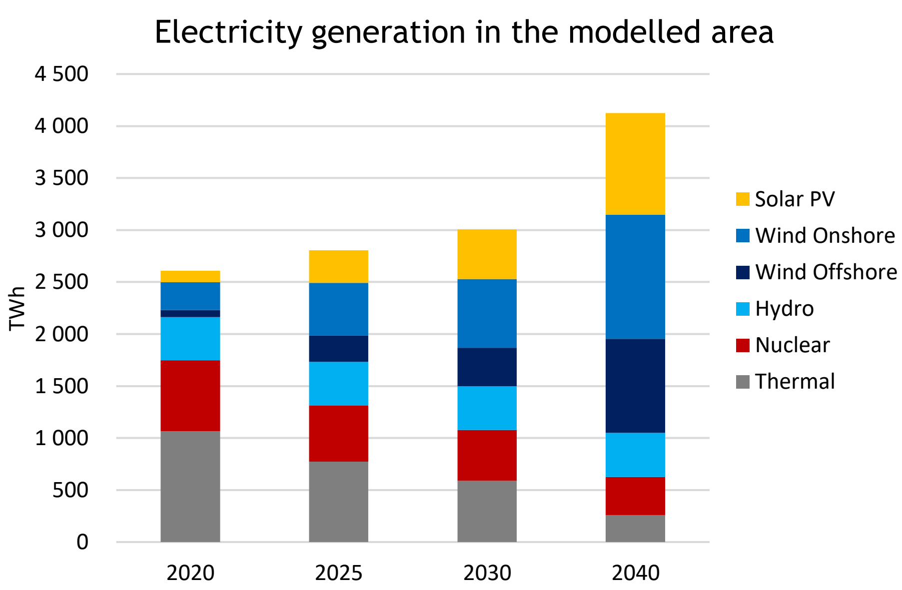


Figure 14 Projected electricity generation in the modelled area.

3.5 Overall development in the Swedish power system

Electricity generation from onshore wind is projected to increase significantly in Sweden from 25 TWh in 2020 to 88 TWh in 2040, shown in Figure 15. This capacity is mainly applied in the Northern regions of SE1 and SE2. Generation from photovoltaic panels (PV) is projected to increase from 1 TWh in 2020 to 8 TWh in 2040. Offshore wind power is projected to increase to 6 TWh in 2040. The majority of PV and offshore wind power capacity is in SE4.

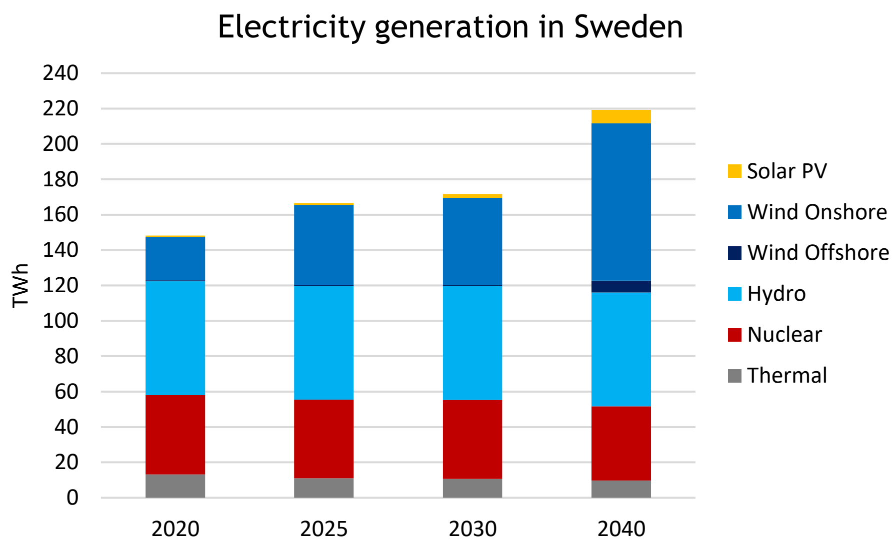


Figure 15 Projected electricity generation in Sweden.

3.6 Overall development in the SE4 bidding zone

This section presents specific results to the SE4 bidding zone in Sweden. The SE4 bidding zone is projected to have modest capacity developments from 2020 to 2030, which can be seen in Figure 16. As stated in the assumptions, the thermal capacity is assumed to decrease as Karlshamnsverket and Heleneholmsverket are decommissioned. The onshore wind power capacity in SE4 is limited by the potential of the region which is estimated to be approximately 10 TWh equaling 3.2 GW in capacity. PV capacity in Sweden is mainly seen in the SE4 region due to a slightly higher number of full load hours compared to the other regions. In SE4, the PV capacity increases to 2 GW in 2030 and then 7 GW in 2040. In 2040, the model invests in 2 GW offshore wind capacity. This is mainly applied as near shore. It should be stressed that local bottlenecks in the power grid could be an important obstacle for realizing the PV deployment envisioned in the reference scenario.

The PtX electricity consumption increase, shown for Sweden in Figure 9, is the main reason behind a need for more capacity of both PV and offshore wind in 2040.

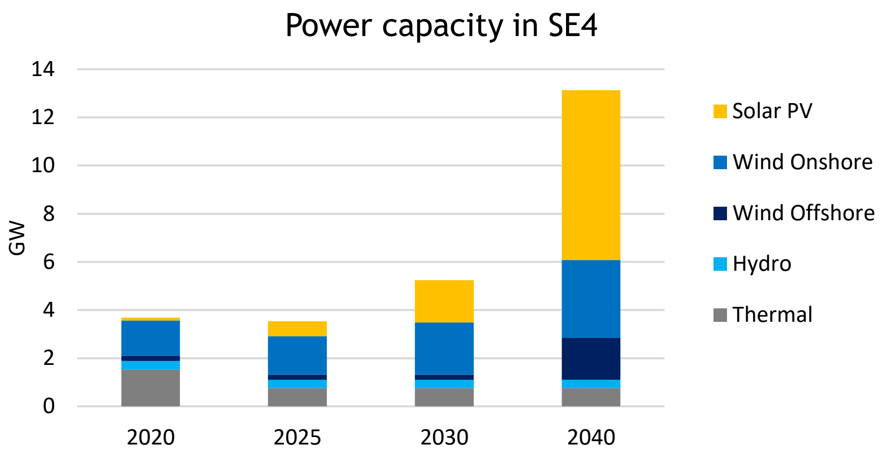


Figure 16 Power capacity in the SE4 region.

The model results show that the remaining 0.6 GW thermal capacity, which is not biomass CHP's, is kept operating through strategic reserve capacity payments. The model has a reserve requirement of 2 GW in Sweden which ensures that a portion of the capacity is kept as reserve (strategic reserve and manual reserve capacity). This production capacity can not take part in the spot market.

The SE4 region is projected to be largely dependent on import from especially SE3 between 2020 and 2030 to satisfy the local demand, as shown in Figure 17. In 2040, the annual net import from neighbouring regions is reduced to 5 TWh due to the increased generation from PV and offshore wind.

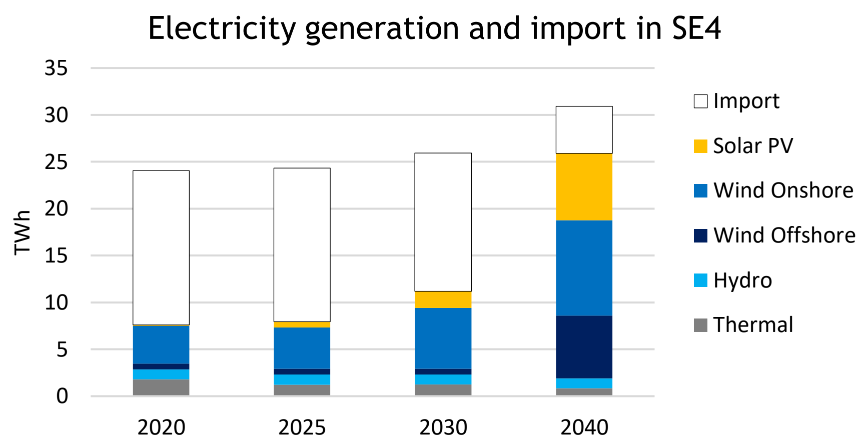
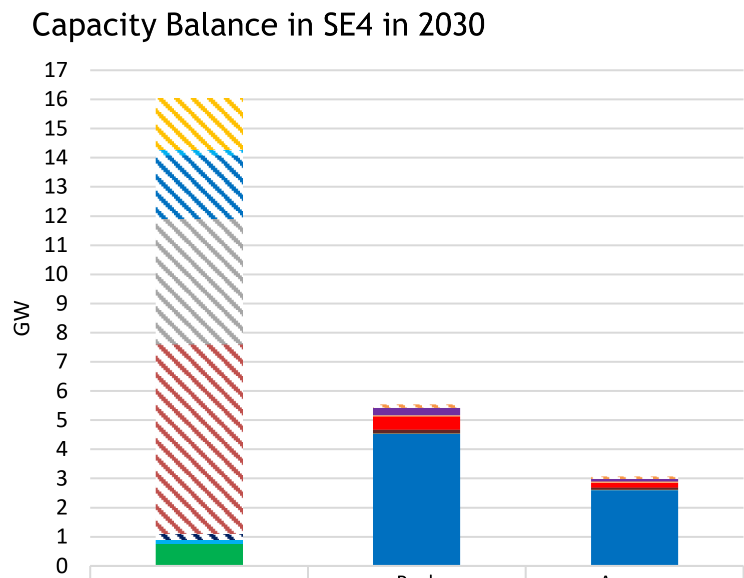


Figure 17 Electricity generation and import in SE4.

As this project investigates the issue of security of supply in SE4, it is important to analyze the capacity balance in the region. This is shown in

Figure 18.



	Reference	Peak demand (winter)	Average demand (summer)
Electrolyzer capacity		0,13	0,09
EV		0,25	0,09
Industrial electrification		0,05	0,05
Individual heating		0,45	0,16
District heating		0,13	0,08
Industrial transport		0,01	0,01
Classic demand		4,53	2,60
Solar PV	1,76		
Hydro - RoR	0,21		
Onshore turbines	2,17		
Transmission capacity to neighboring regions	4,30		
Transmission capacity SE3-SE4	6,50		
Offshore turbines	0,21		
Hydro - Res	0,15		
Thermal	0,75		

Figure 18 Capacity balance in SE4 in 2030.

In 2030, the winter peak demand is estimated to increase to 5.5 GW compared to 5 GW in 2020, mostly due to rising electric vehicle (EV) demand, electrification of the individual heating demand and PtX demand. The summer daytime demand is on an average around 3 GW. Electricity demand used at district heating and PtX plants is assumed not to contribute to peak demand, since these loads are usually flexible and would therefore be disconnected in case of extreme electricity prices. The thermal capacity is based on Svenska Kräftnet’s assumptions which is 750 MW in 2025. The transmission capacity from SE3 to SE4 totals 6.5 GW in 2030, compared to 5.3 GW in 2020, due to the expansion project SydVästlänken which is expected to be finished in 2022. SE4 holds an additional 4.3 GW of transmission capacity to DK2, Germany and Poland. As it can be seen, the SE4 region is relatively well connected and has more than enough transmission capacity to supply the peak demand through imports. The main issue is therefore whether there is sufficient generation capacity available for export in the neighboring areas in a scarcity situation? According to the Balmorel model, which looks at a typical weather year, that is the case in all hours but about 20-30 (see next section). To explore this issue in more detail other tools would be required that apply stochastic modelling of outages of power plants and transmission lines along with examining the situation in a multitude of years with different weather conditions.

3.6.1 Power price development in SE4

The power price in SE4 is another interesting parameter to investigate, as it is obviously of pivotal importance to the feasibility of existing power producers and potential investments in new generation capacity. The historic SE4 power prices of 2018 and 2019 are shown in Figure 19 along with the projected prices of 2030 and 2040. The projected 2030 average power price in SE4 is projected to be 431 SEK per MWh which is higher relative to the 2019 average price of 420 SEK per MWh. The average price in 2040 is projected to be 444 SEK per MWh. However, the changes in average prices may be modest, but the price volatility increases.

The price profiles show the effect of increased generation from renewables as higher and lower price hours are present in the duration curve.

There are approx. 20-30 hours where the power price reaches the price ceiling in the market in 2030 and 2040. In these hours there is not sufficient generation capacity in the spot market to cover demand, and as a result, consumers would have to be disconnected or the strategic reserves would have to activated. This result shows that the power balance is tight. More specific tools would be required to determine in more detail to what extent involuntary disconnection of consumers is needed. That result is also sensitive to whether some consumers will voluntarily choose to abstain from using electricity when extreme prices are observed.

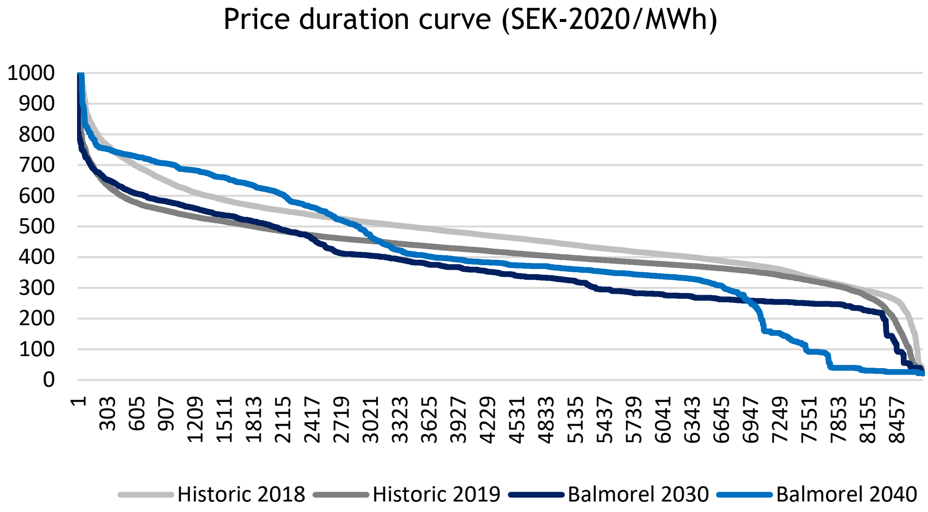


Figure 19 Price duration curves of SE4.

3.6.2 Dispatch curves in 2030 – winter and summer weeks

As an output from the model, we can examine operational dispatch curves to see unit operation, power prices, electricity consumption and import/export in the individual bidding zones. Figure 20 shows the operational dispatch of SE4 in a winter week.

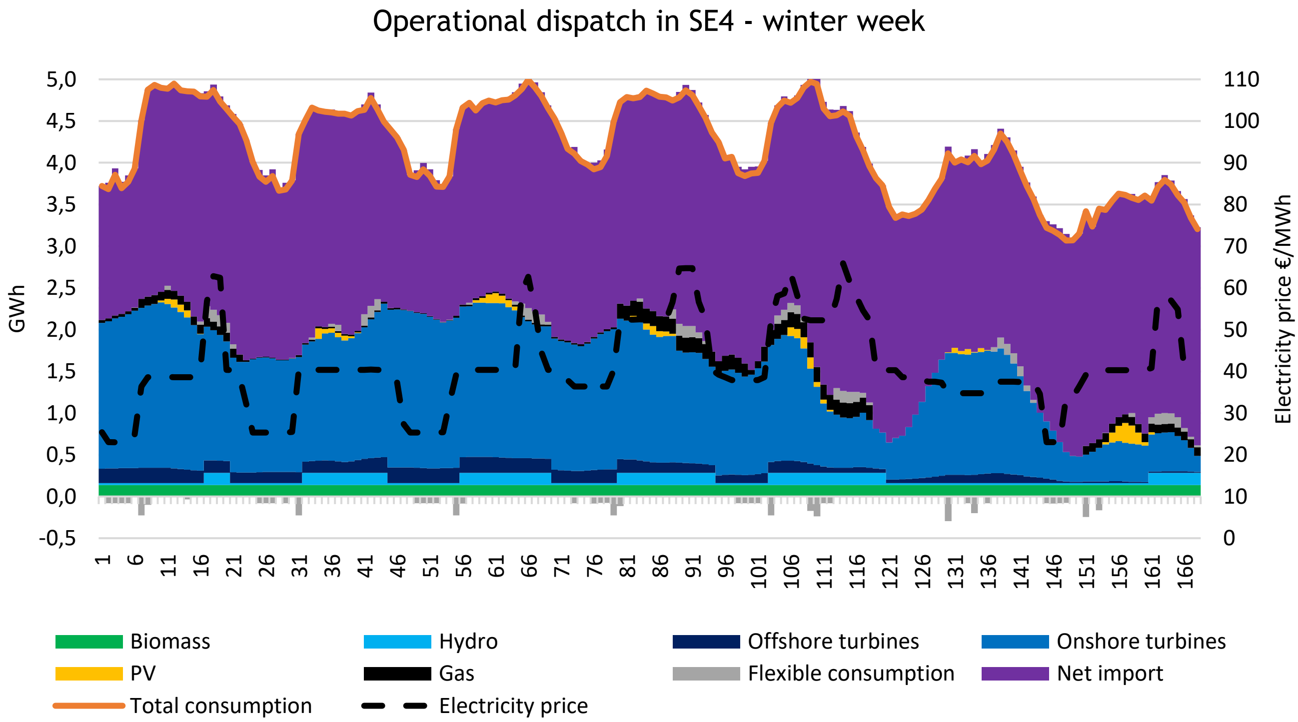


Figure 20 Operational dispatch of a winter week in SE4 in 2030.

The Figure shows that total electricity consumption is high in the daytime hours, reaching 5 GW. Most of the demand is supplied by import from cross area border transmission lines. Generation from onshore wind is high and fairly constant throughout the period which characterizes a winter week. The power prices increase to the extent that the gas turbines of the region are activated in a few hours to supply the consumption.

In contrast, a summer week in SE4 is shown in Figure 21. The Figure shows that generation from onshore wind are comparatively lower throughout the week and solar PV provides large quantities of generation in the daytime hours. There is also a need for import throughout this week similarly to the winter week. The electricity consumption of this week is on average significantly lower compared to the winter week, as average daytime consumption reaches around 3 GW an hour compared to 5 GW an hour. The power price is stable at around 30 € per MWh which is a strong contrast to the volatile winter week prices. The hydro units operate to a higher degree as baseload due to the stable price pattern.

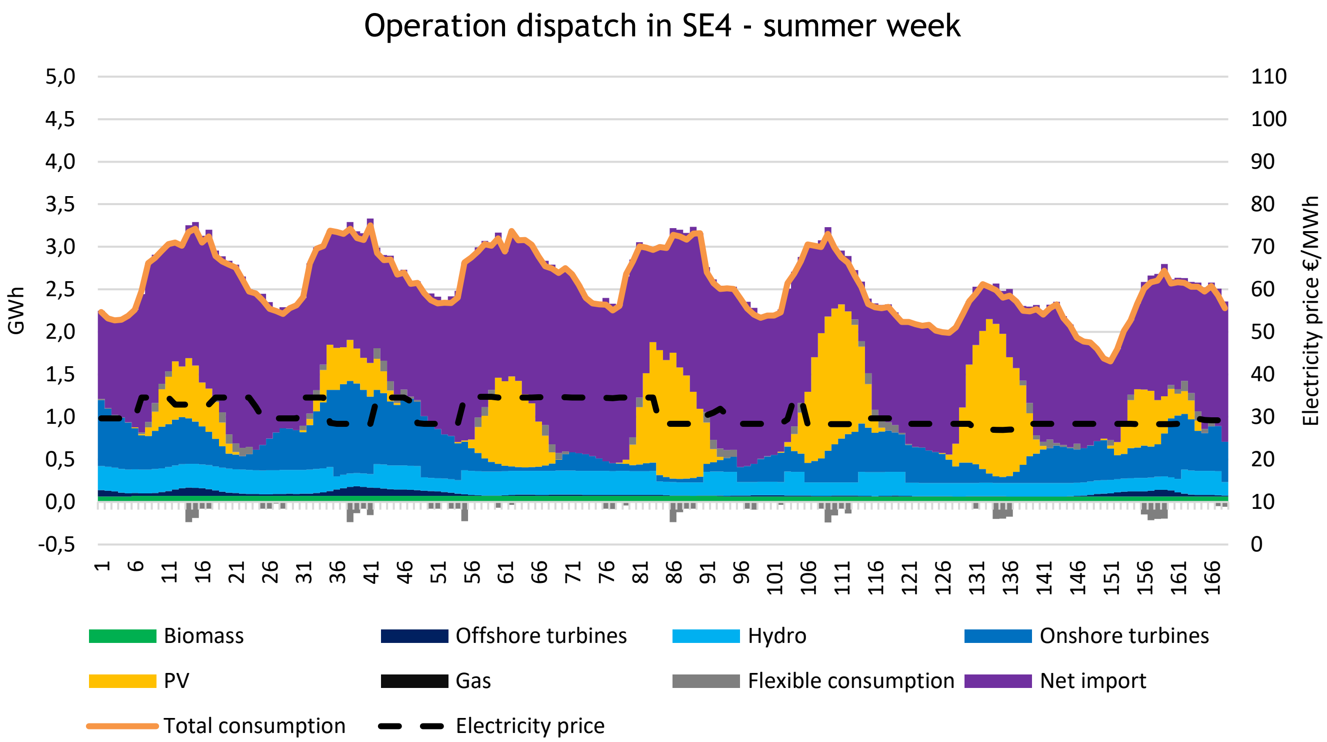


Figure 21 Operational dispatch of a summer week in SE4 in 2030.

3.7 Sensitivity analyses

This sensitivity analyses explores four different scenarios:

- High demand scenario
- NIMBY - scenario
- Delayed electrification
- Thermal sensitivity

The first three scenarios are investigated in the following section. These scenarios have different capacity buildouts in Sweden as shown in Figure 22.

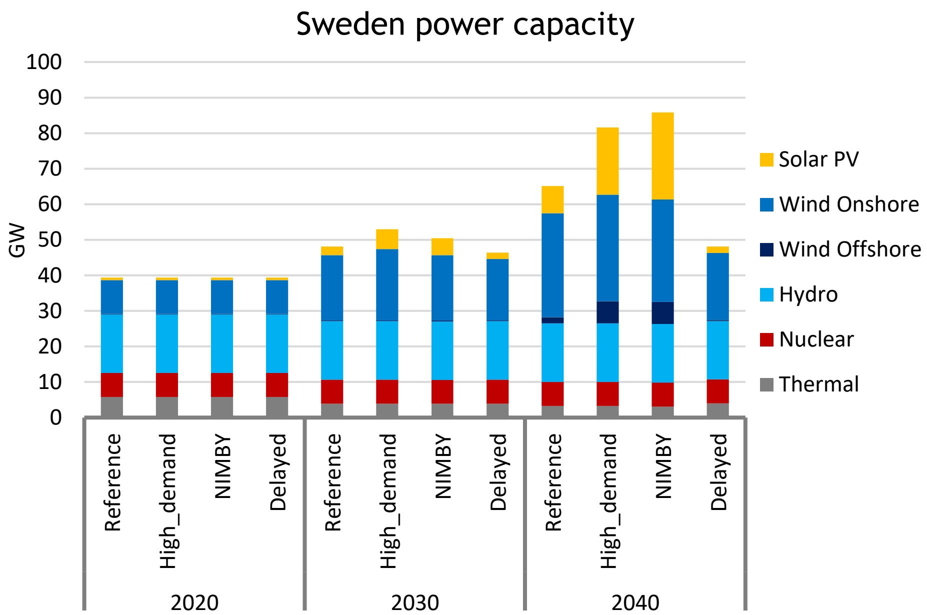


Figure 22 Power capacity in Sweden in different scenarios. Data table is in appendix.

The projected capacity in each scenario is relatively similar in 2030 with additional 4 GW in the high demand and NIMBY scenarios. In 2040, we see major changes in the sensitivity with large amounts of PV and offshore wind capacity being added in the high_demand and NIMBY scenarios. The PV capacity increases to 19 and 25 GW in these scenarios compared to a projected reference capacity of 8 GW in 2040. The demand for additional PV capacity in the high_demand scenario is linked to the increase in electricity demand of 50 TWh by 2040. Interestingly, the high_demand scenario is the only scenario which utilizes all onshore wind potential of 30 GW in 2040 as both the reference and NIMBY contain 29 GW respectively. This indicates that PV, onshore and offshore wind are on par cost-wise by 2040. This is a consequence of decreasing costs of PV and offshore turbines. The delayed electrification scenario shows a different story as the electricity consumption remains at a fairly constant level in all years which results in small amounts of additional onshore capacity.

The transmission capacity expansions in each scenario are fixed up until 2030 and follows the TYNDP18 planned expansions, as shown in Figure 23. From 2030 the model can invest in additional transmission capacity between regions up to 1,500 MW per 5 years. In the 2040, the model utilizes the full expansion potential to SE3 and Poland in all scenarios, installing 3 GW to both these regions. Capacity expansion to the other regions is more modest. SE4 is to a large extent used as a transit area, moving cheap green electricity from Northern Sweden to continental Europe as 38 TWh is imported from SE3 and 35 TWh is exported to Poland, Germany and Denmark in the reference in 2040. The NIMBY scenario shows an approximately 6 GW higher transmission expansion relative to the other scenarios due to 5 GW additional capacity to German regions and 1 GW to Lithuania.

Previous analyses have shown that there are bottlenecks in the central German grid due to a high demand in Southern Germany. This bottleneck effect is amplified in the NIMBY scenario which contains further limitation on solar PV and onshore wind in central Germany which creates an increased import demand to the region. Further geographical representation of the transmission flows between regions in the reference and NIMBY scenarios are present in Appendix 6.4.

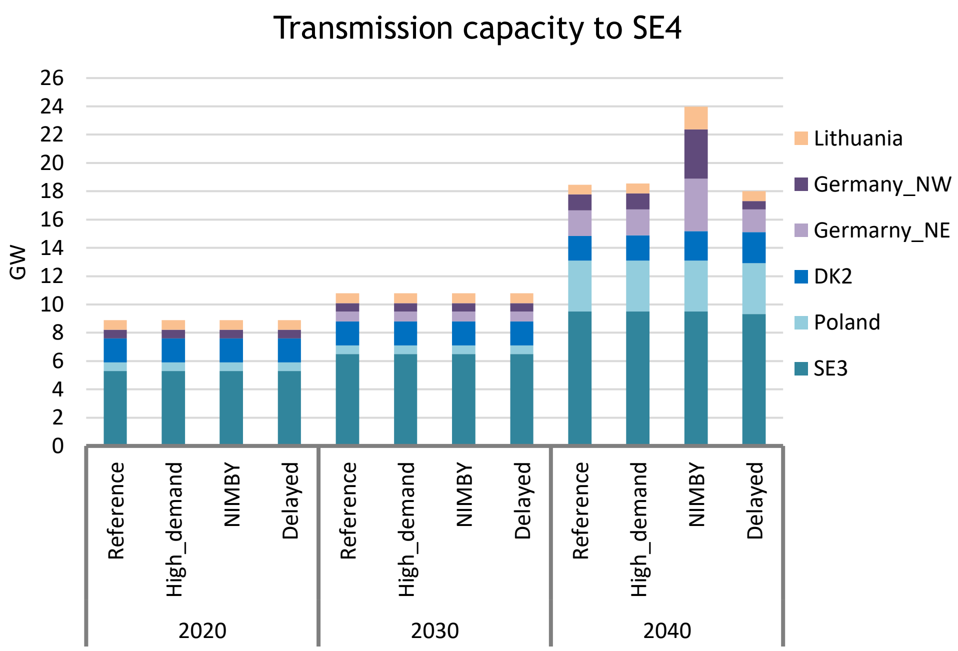


Figure 23 Transmission capacity development in SE4 in different scenarios.

Figure 24 shows the power capacity in SE4 in each sensitivity scenario in 2030 and 2040. In 2040, the Figure shows that all offshore capacity and a large part of the PV capacity in Sweden is located in SE4 in the high_demand and NIMBY scenarios. The remaining PV capacity of Sweden is distributed across mainly the SE3 and the SE2 region close to load centres. The delayed electrification scenario shows a significant impact on the PV and offshore turbine buildout while the onshore turbine buildout remains constant in all scenarios.

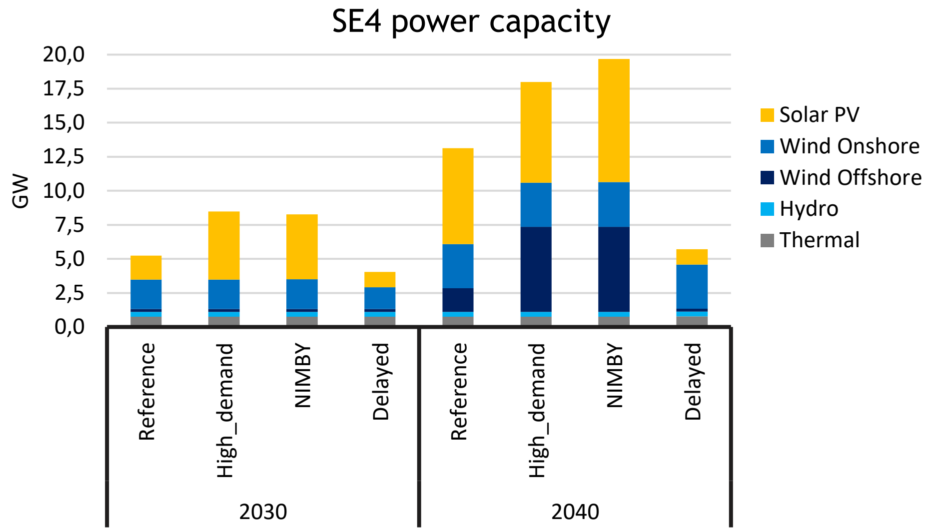


Figure 24 Power capacities in each scenario in SE4.

Figure 25 show that SE4 remains a net importer in the reference and delayed electrification scenarios while a net export is obtained in the high_demand and NIMBY scenarios mainly due to generation from offshore turbines.

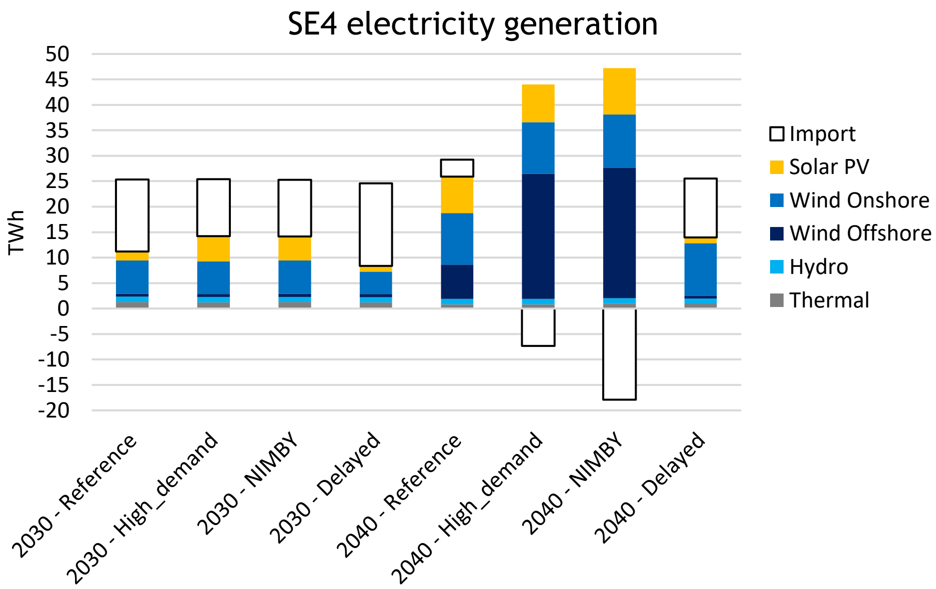


Figure 25 Electricity generation in each scenario in SE4 in 2030 and 2040.

3.7.1 Focus on thermal power capacity

The reference scenario assumes refurbishment of existing thermal capacity so that lifetimes are extended to 2040.

Table 5 shows in which market each individual power plant operates in different years in the reference scenario.

Table 5 Power plant operation in the reference scenario with assumed refurbishment of most power plants.

Plant	Fuel	2020 operation	2030 operation	2040 operation
Alloverket 1	bio	Spot market	Spot market	Spot market
Vasthamnsverket 1	bio	Spot market	Spot market	Spot market
Minor biomass plants	bio	Spot market	Spot market	Spot market
Vasthamnsverket GT	gas	Spot market	Spot market	Strategic reserve
Öresundsverket GT G24	gas	Spot market	Spot market	Strategic reserve
Karlshamnsværket	gas	Spot market	Spot market	Strategic reserve
Karlshamnsværket	oil	Strategic reserve	Decommissioned	Decommissioned
Heleneholmsverket	oil	Strategic reserve	Decommissioned	Decommissioned
Minor fuel oil plants	oil	Strategic reserve	Strategic reserve	Strategic reserve

In the reference scenario, the biomass units Alloverket, Vasthamnsverket 1, and the aggregated category “minor biomass plants” participate in the spot market. The gas power plants of Vasthamnsverket, Karshamnverket and Öresundsverket all participate on the spot market until 2040 where their contribution margin switch to being capacity payments exclusively due to high CO_2 prices. The oil units in the aggregated category “minor fuel oil plants” exclusively function as strategic reserves to stay online for all years as their marginal costs are too high to have reasonable revenues in the spot market.

In the reference scenario the existing power plants are assumed to available for the power market until 2040 assuming that the regular annual operation and maintenance costs are sufficient to keep the plants operational. A sensitivity scenario is created assuming 25-year lifetime of all power plant to see whether the model would choose to refurbish the units when their lifetime is exceeded. Table 6 show an overview of power plants in SE4 with capacities and assumed end-of-life time years.

Table 6: SE4 plant overview of capacity and assumed decommissioning years in the thermal capacity sensitivity analysis. In the reference scenario the existing power plants are assumed to

available for the power market until 2040 assuming that the regular annual operation and maintenance costs are sufficient to keep the plants operational

Plant	Fuel	MW	Commissioned	End of life time
Allöverket 1	bio	14	2013	2038
Västhamnsverket 1	bio	69	2006	2031
Västhamnsverket GT	gas	54	2000	2030
Heleneholmsverket	oil	126	1960	2024
Öresundsverket GT G24	gas	128	2009	2039
Karlshamnsværket	oil	670	1973	2024
Karlshamnsværket GT	gas	35	2000	2030
Minor biomass plants	bio	47	2013	2038
Minor fuel oil plants	oil	357	2000	2030

Figure 26 shows the model results of the sensitivity analysis. The results show that all existing thermal capacity is fully decommissioned by 2040. This means that the model does not find the potential contribution margin enough to cover refurbishment investment costs for fuel-oil, gas, and other biomass related units. However, a 200 MW new biomass CHP plant is established in 2040 which runs on low biomass fuel costs from the usage of wood waste which is limited in the model. The economic analysis in section 4 will investigate this biomass CHP type further.

The alarming results is that the SE4 region is by 2040 left with just 0.2 GW of thermal capacity to cover a peak demand of more than 5.5 GW. It should be stressed, that in the model the requirement for reserve capacity is defined at a national level and therefore it does not take into account that Svenska Kraftnät would require a portion of the disturbance reserve to be located in SE4.

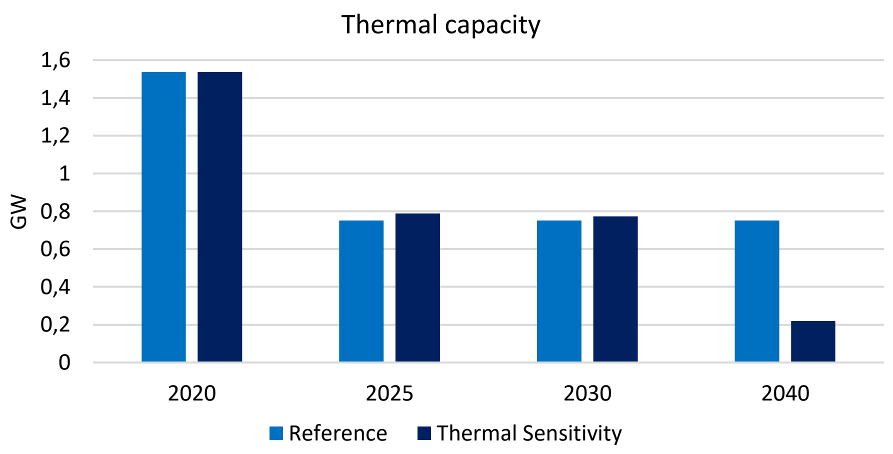


Figure 26 Thermal capacity development in SE4 in each scenario. The thermal sensitivity assumes 25-year lifetime of thermal generators. At end-of-life time the model can choose to refurbish the plant or decommission it.

4 Thermal Generator Economy in SE4

Using the power price projections for SE4 from the Balmorel model, a separate market simulation tool is applied for the analysis of thermal power plant economy.

This market simulation tool can provide information on the operation of thermal generators in the spot market as well as in regulating power market. The focus of this part of the analysis is only 2030. However, it should be stressed that determining revenues in the regulating power markets is associated with a high level of uncertainty and these results should therefore be interpreted with caution.

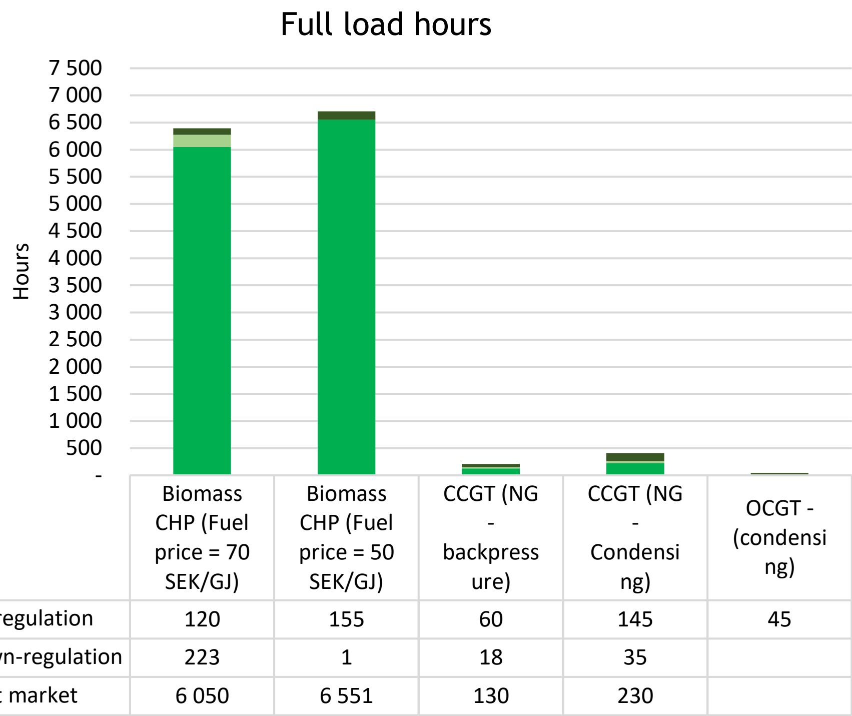
We investigate four theoretical new thermal generator technologies. Due to the uncertainty related to the cost of procuring biomass we are investigating two biomass price levels:

- Wood chip combined heat and power – backpressure
  - which is able to procure biomass at a cost of **50 SEK per GJ**
  - which is able to procure biomass at a cost of **70 SEK per GJ**
- Combined cycle gas turbine – backpressure.
- Combined cycle gas turbine – condensing.
- Open cycle gas turbine – condensing.

The thermal generators are not assumed to affect power prices. This is a realistic assumption for small units. Larger units may cause a small reduction in power prices, implying that the analysis may slightly overestimate revenues in the power market for such units. Appendix 6.3 presents a more detailed documentation on the market simulation tool.

4.1 Results of thermal generator economics

Figure 27 show the full load hours obtained by each of the four thermal generation technologies on the spot- and regulation power markets. Regulating power is divided between up- and down regulation.



	Biomass CHP (Fuel price = 70 SEK/GJ)	Biomass CHP (Fuel price = 50 SEK/GJ)	CCGT (NG - backpressure)	CCGT (NG - Condensing)	OCGT - (condensing)
Up-regulation	120	155	60	145	45
Down-regulation	223	1	18	35	
Spot market	6 050	6 551	130	230	

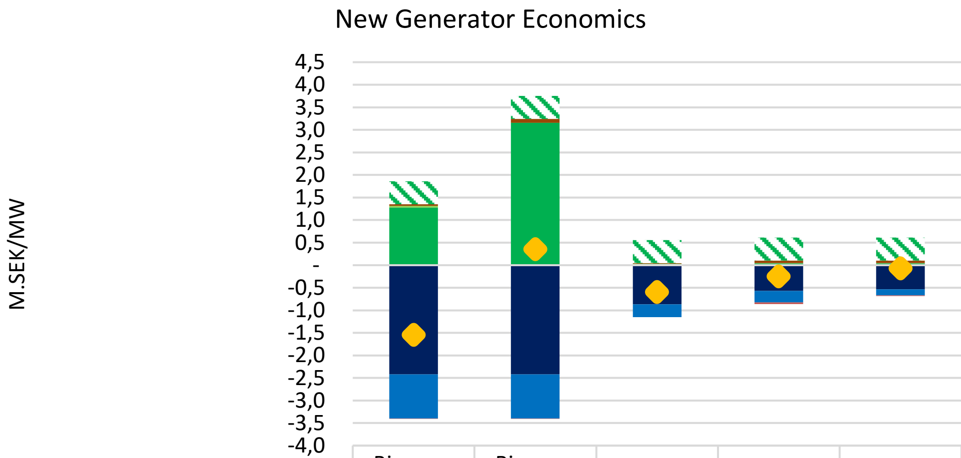
Figure 27 Full load hours of each technology.

The wood chip CHP technologies operate as baseload units in the spot market with 6,050 and 6,551 full load hours. The biomass CHP with reduced fuel cost operates to a higher degree on the spot market due to lower marginal costs. The CCGT – backpressure unit is heavily affected by high taxation on district heating from natural gas units. The current regulation taxes heat from natural gas-fired CHP units by 93.3 SEK per GJ heat. This gives a very low – and in many hours non-existing - contribution margin from heat sales. The CCGT – condensing and OCGT units operate as peak units with low amounts of full load hours in each market due to high marginal costs. The condensing unit has higher revenues than the CHP unit, indicating that given the high taxes on heat natural gas, it would be more profitable for the owner of the CHP power plant to operate the plant in condensing mode and stop district heating production if this was technically possible.

Figure 19 showed that average prices in the SE4 regions increase in 2030 and 2040 compared to the historic years of 2018 and 2019. This creates better conditions for thermal generators as they are more likely to be able to cover their costs.

The economic results of the market simulation tool are presented in Figure 28. The positive figures in the graph show the contribution margin made from power sales in spot and intraday markets, i.e. difference between the electricity price and the marginal cost of power generation for the unit. The contribution margin from scarcity prices is specifically for very high price hours. The fixed cost of the power plants, divided on fixed operation and maintenance cost and capital costs, along with start-up costs are presented as negative figures.

A fixed heat price is assumed with respect to the combined heat and power plants based on data from Energiforsk. The heat price of biomass CHP units is set to 11.2 € per GJ while the natural gas-fired units receive a price of 14.9 € per GJ because they usually operate in peak demand periods where the price is typically higher.



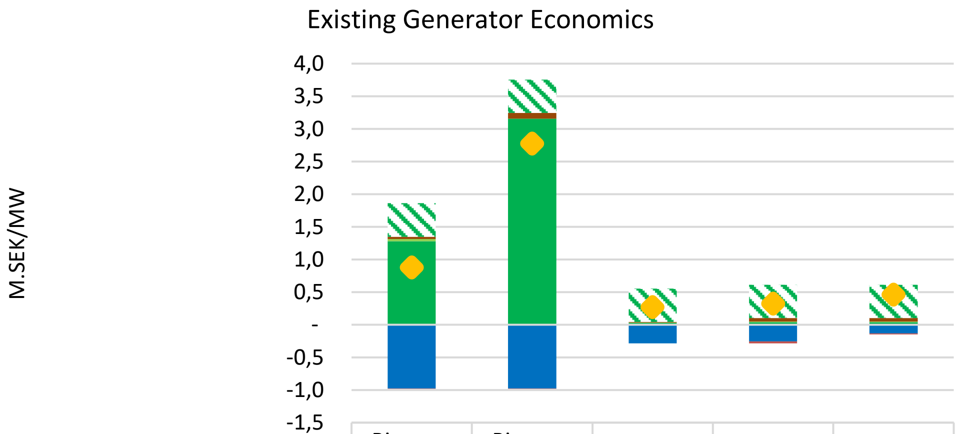
	Biomass CHP (Fuel price = 70 SEK/GJ)	Biomass CHP (Fuel price = 50 SEK/GJ)	CCGT (backpressure)	CCGT (condensing)	OCGT - (condensing)
Contribution margin from scarcity prices	0,51	0,51	0,51	0,51	0,51
Contribution margin from up-regulation	0,04	0,09	0,01	0,05	0,05
Contribution margin from down-regulation	0,03	0,00	0,00	0,01	0,01
Contribution margin from spot market	1,28	3,16	0,02	0,04	0,04
Start up costs	-0,01	0,00	0,01	-0,03	-0,01
Annual fixed O&M	-0,98	-0,98	-0,28	-0,26	-0,13
Annualized investment	-2,42	-2,42	-0,87	-0,57	-0,54
Annual profit	-1,54	0,36	-0,60	-0,25	-0,07

Figure 28 New thermal generator economic results from market simulation tool.

The wood chip CHP unit technologies show the highest contribution margin from the spot market. However, only the biomass CHP with a reduced fuel price of 50 SEK/GJ obtains a contribution margin which covers investment and fixed costs, making it a new positive investment. This shows how sensitive the biomass CHP investments are to the future fuel prices.

All the investigated technologies earn 0.51 million SEK from scarcity prices on 30 hours where the power price is averagely around 17,000 SEK per MWh. As expected, the gas turbine technologies show a high dependency on scarcity prices to cover their costs. The CCGT – backpressure unit shows very little contribution margin from each market, giving it a yearly loss of 1.11 million SEK per year. The peak units of CCGT condensing and OCGT shows lower yearly losses of 0.76 and 0.58 million SEK respectively, due to lower investment and fixed costs relative to the other technologies.

The same analysis concerning generator economics is now applied on the same units as before but this time excluding capital cost in order to represent the economy of theoretical existing units, where capital cost are considered sunk cost . Figure 29 shows the results.



	Biomass CHP (Fuel price = 70 SEK/GJ)	Biomass CHP (Fuel price = 50 SEK/GJ)	CCGT (backpressure)	CCGT (condensing)	OCGT - (condensing)
Contribution margin from scarcity prices	0,51	0,51	0,51	0,51	0,51
Contribution margin from up-regulation	0,04	0,09	0,01	0,05	0,05
Contribution margin from down-regulation	0,03	0,00	0,00	0,01	0,01
Contribution margin from spot market	1,28	3,16	0,02	0,04	0,04
Start up costs	-0,01	0,00	0,01	-0,03	-0,01
Annual fixed O&M	-0,98	-0,98	-0,28	-0,26	-0,13
Annual profit	0,88	2,78	0,27	0,33	0,46

Figure 29 Existing thermal generator economics.

The Figure shows that, if investment costs have been covered, wood chip CHP’s have the highest net profit of 2.78 million and 0.88 SEK per year followed by OCGT which obtains 0.46 million SEK a year.

In conclusion, investment in new gas turbine power plants appears to be non-economically feasible due to low contribution margins from both spot- and intraday markets. Closed cycle gas turbines require an additional 0.25 million SEK a year per MW to be economically feasible and open cycle turbines require only 0.07 million SEK/MW which makes open cycle close to break-even. The results show a high sensitivity to the chosen fuel price of biomass CHP technologies as using a fuel price of 70 SEK per GJ provides a non-economically feasible investment and a lower price of 50 SEK per GJ is economically feasible. Additionally, the contribution margin obtained in the regulation market is quite limited for all technologies. However, existing thermal units, where capital costs are considered sunk cost, can have a net positive turnover as contribution margins are higher than total costs.

5 Conclusion and recommendations

Power market analysis

The power market analysis shows that only solar PV, onshore and offshore wind demonstrate economically feasible investments. The Balmorel model does not invest in new thermal capacity but it does not decommission the existing capacity either as long as major re-investments are not required. In this case the existing capacity is kept online despite the high CO_2 prices, which increase to 83 € per ton in 2040. The fuel-oil and light-oil units cannot compete in the spot market, but they receive reserve payments between 2020 and 2040. The natural gas-fired units operate on the spot market until 2040 where the CO_2 price becomes too high for spot market participation. In 2040, these units act as reserve capacity exclusively. From a modelling perspective, this shows a need for capacity payments if existing thermal capacity should be maintained.

In a sensitivity analysis, where existing power plants are assumed to require refurbishments after 25 years of lifetime (which is not an unrealistic assumption) we see that all existing thermal capacity is decommissioned between 2030 and 2040 and replaced with 200 MW of new biomass CHP capacity. This worrying result exposes that SE4 could potentially be left with just 0.2 GW of thermal capacity by 2040 if no dedicated measures are put into play to safeguard security of supply. It is important to mention that this development would not necessarily lead to disconnection of consumers because SE4 under normal conditions would be able to import power from neighbouring jurisdictions, but it could leave SE4 in a more vulnerable position than today.

Market simulation tool

Further analyses using a bottom-up based market simulation tool, that considers revenues in spot and regulating power markets, show that many new thermal generators cannot obtain an adequate contribution margin to cover investment costs in SE4 in 2030. Biomass CHP fuelled by wood chip needs a fuel price of 50 SEK per GJ or lower to be economically feasible in SE4 in 2030. Contribution margins from the regulating power market appear to be rather limited with respect to all thermal generator technologies. Condensing closed cycle gas turbines require an additional 0.25 million SEK a year per MW to be economically feasible. Condensing open cycle turbines require only 0.07 million SEK/MW which makes open cycle turbines close to break-even.

Other sources of revenue	Ancillary services such voltage control is another other source of income that has not been investigated in this analysis due to the limitations of the Balmorel model and the market simulation tool. The need for frequency control is it least partly considered through the reserve requirements. However, the thermal generator economic results showed that there is a substantial gap between total costs and the contribution margin required to have economically feasible investments. It is unlikely that the gap can be closed by voltage ancillary services alone.
Offshore opportunities	The High Demand and NIMBY sensitivity scenarios results show an opportunity for offshore turbine expansion in the SE4 bidding zone. Offshore turbine deployment could potentially improve security of supply since it provides a relatively stable power production with a fairly high capacity factor and at the same time introducing offshore wind in Southern Sweden would have a downward effect on power prices. An interesting opportunity lies in the development of interconnected offshore wind farms grid in the Baltic Sea. Combining offshore capacity with increased interregional transmission capacity could be a way of further improving security of supply through stronger access to generation resources in Poland, Germany and Denmark. Denmark and Germany are already interconnected at Kriegers Flak and Denmark plans for an additional 2 GW of offshore capacity at Bornholm. Thus, there appears to be ample opportunities for the Skåne Region and Sweden to exploit offshore wind power in cooperation with its neighbours in the Baltic Sea.
Strengthen interconnectors to continental Europe	Even if a strategy for interconnected offshore wind is not pursued, the analyses indicate a need for strengthening the interconnectors between Sweden and continental Europe, as a means to transit green power from the northern parts of Sweden to consumers in Germany and Poland. In 2040, the model utilizes the full expansion potential to SE3 and Poland in all scenarios, installing 3 GW to both these regions. Enabling these opportunities would improve security of supply in Southern Sweden but could potentially raise average power prices because continental Europe in general displays high prices compared to Scandinavia. For the owners of the interconnectors (typically the TSO, i.e. Svenska Kraftnät) interconnectors would provide a source of income in the form of congestion rents.
Solar power	The analysis shows good opportunities for solar power in Southern Sweden, solar conditions appear to be slightly better than in Northern Sweden and at

the same time power prices in SE4 are higher than in the other Swedish bidding zones, improving the business case for solar PV.

6 Appendix

6.1 Documentation of the Balmorel Model

Balmorel is a detailed techno-economical partial equilibrium model suited for analyses of electricity as well as combined heat and power markets. It is capable of both investment and dispatch optimisation. In the investment mode, it can simultaneously determine the optimal level of investments, refurbishment and decommissioning of electricity and heat generation and storage technologies as well as transmission capacity between predefined regions. In the dispatch optimisation mode, it determines the market optimal utilisation of available generation and transmission capacity. It is capable of both time-aggregated as well as hourly modelling, to fit the analysis to the right level of geographical, technical and temporal detail. It is particularly suited to address the interdependency between heat and electricity production of combined heat and power (CHP) generators.

The mathematical principle behind Balmorel is based on finding a least cost solution for the dispatch and investments within the regarded interrelated electricity and district heating markets. Doing so, Balmorel considers developments of electricity and heat demand, grid constraints, technical and economic characteristics for each kind of production unit, fuel prices, spatial and temporal availability of primary renewable energy, etc.

The model has been continuously developed and distributed under open source ideals since 2001. The GAMS based source code and its documentation is available for download on (www.balmorel.com). The Balmorel developers are active members of the open energy modelling initiative (www.openmod-initiative.org), an international platform for knowledge exchange and the promotion of open source and open data within the energy modelling sector.

The model is highly versatile and has been successfully applied for long-term planning and scenario analyses, and short-term operational analyses on both international as well as detailed regional levels. It has been used by several institutions and companies, including Ea Energy Analyses, Technical University of Denmark (DTU), Tallin University of Technology, Norwegian Univerity of Life Sciences (NMBU), Elering (Estonian TSO), Litgrid (Lithuanian TSO), the Danish Energy Association, Grøn Energi, and HOFOR. Many projects have been carried out related to the Danish, Nordic, and European combined heat and power systems. In addition, the Balmorel model has been applied in Canada, Mexico, Vietnam, China, Indonesia, India, Western Africa, South Africa, and

Eastern Africa. Ea Energy Analysis is the leading company in terms of commercial engagement with Balmorel model and is currently active in modelling projects in several of the aforementioned countries[3].

The model fulfils all the most relevant aspects to be covered by power system planning tools used to model systems with high amount of variable renewable energy, as outlined by (IRENA, 2017). Indeed, its characteristics are:

- Co-optimization of dispatch and new investments: non-marginal analysis of new capacity addition and consideration of capacity factor evolution of traditional plants
- Co-optimization of new transmission and generation capacity, to include trade-off between resource quality and distance to load centers
- Consideration of interplay of power and other sectors, such as district heating and transport sectors
- Good representation of RE variability based on hourly meteorological data and detailed modelling on the impact on the residual load
- Flexible, customizable, and scalable in terms of geographical and temporal resolution
- Open Source

In terms of geo-spatial and temporal resolution, Balmorel is very flexible and can be setup with varying level of details depending on the interest and data availability. As for temporal resolution, the model can go down to the hourly level for a full year. In terms of geospatial resolution, normally setup depending on dispatch areas and congestions in the transmission-distribution grids.

Since the model has a detailed representation of the power sector, e.g. with the individual power plant described, the work of collected the needed data will take some time. However, once the model setup is complete, it is very quick to run an alternative scenario. Within a few hours an

[3] A large number of projects are available at: http://www.ea-energianalyse.dk/projects_uk.html.

alternative policy goal, or technology costs can be formulated and computed. Easy-to-use Excel files are used to share both input data and model results.

An overview of the structure of the model and the inputs needed is displayed in the Figure below.

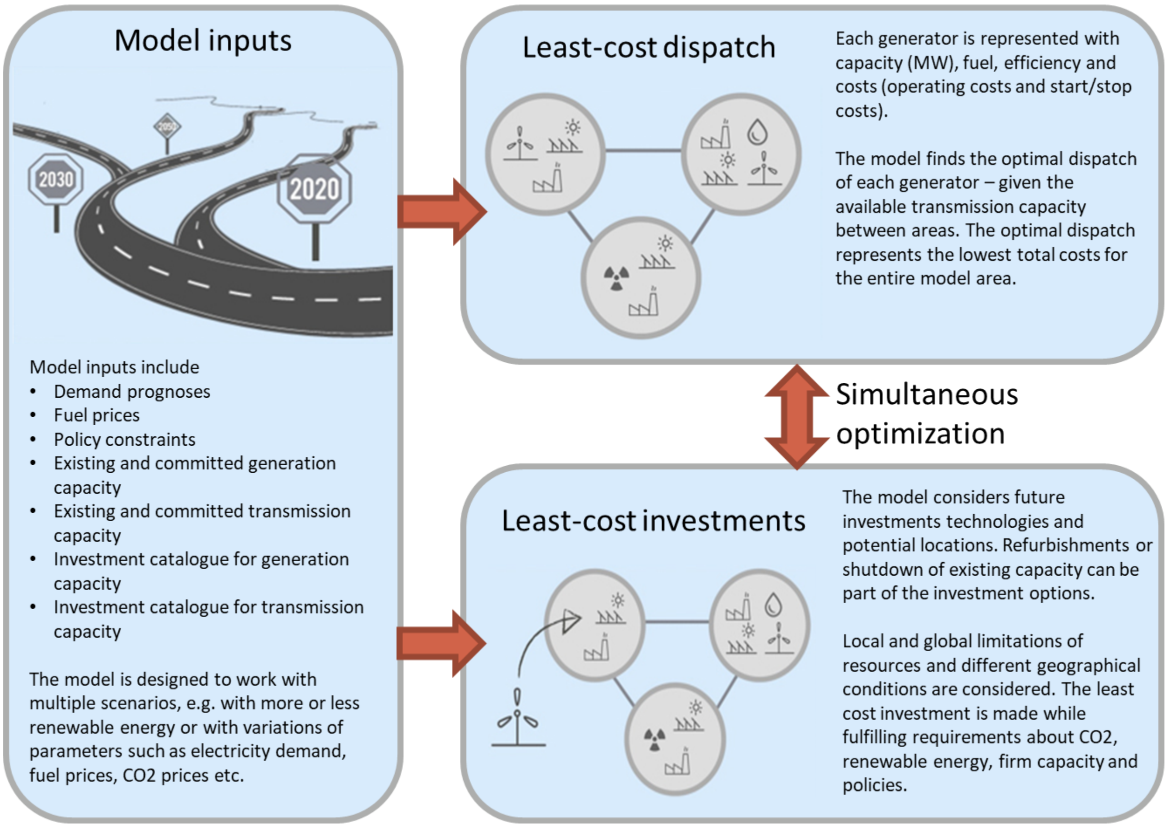


Figure 30. Overview of Balmorel model structure.

Since the model simulates both least-cost investment and least-cost dispatch, the outputs include both the evolution of the generation fleet overtime in the different scenarios, and the actual dispatch of the system to supply the power demand in each hour at the lowest possible cost.

Model outputs include but is not limited to:

- Investments in new generation capacity by technology and fuel
- Power Generation down to hourly level for each power plant represented
- Hourly electricity price for each modelled region
- System costs (CAPEX, fixed and variable OPEX, fuel cost, emission cost) by fuel, region and total for the country
- Emissions and cost of CO_2 and pollutants

- Stakeholders economy, down to each power plant
- Fuel consumption

6.2 Consumption terminology

- **Classic demand** contains all demand which does not fall under the other categories. The demand is mainly modelled with demand profiles based on the consumption in 2014.
- **Electric vehicles demand** includes all electricity for road transport. This demand is flexible, and an increasing share can be moved for 4 hours.
- **Electricity for individual heating** includes electricity consumption for space heating in buildings, which is modelled as heat demand. The demand is supplied by heat pumps and electric boilers. All the individual heat demand is flexible and can be moved 4 hours.
- **Electricity for electrification of industrial energy demand** is included as the growth in electricity use in the industrial sector (compared to 2015), considering increasing energy efficiency. The demand is modelled as heat demand which can be fully supplied by coal, natural gas and oil boilers. When advantageous, additional electric boilers can be installed to supply the heat demand.
- **Electricity for district heating** is based on model optimization. Heat pumps and electric boilers are among the options to supply the district heating demand. Other options are fuel based district heating generation from heat only boilers or CHP.
- **Electricity for P2X** is included based on the consumption of e-gasses, e-liquids and hydrogen. A P2X efficiency of 70% is assumed for hydrogen and 60% for e-gasses and e- liquids. If profitable, storages can be installed to move portions of the demand.

6.3 Market simulation tool documentation

A market simulation tool has developed to determine how thermal power plants will dispatch their generation in the spot and regulating markets

- The aim of the tool is to mimic realistic market behaviour (approximation)
- For thermal power plants the tool considers start-up costs and minimum-load, planned outages and heat off-take (CHP)
- Participation of a generator in one market (for example spot market) may exclude the participation in another market (for example up regulation market)
- **Full load hours are a model output**

Development of the balancing market is highly uncertain, both in terms of prices and volumes. A number of factors affect the development:

Factors increasing volume and/or prices

- Increased shares of variable renewable energy in the power system with associated forecast uncertainties
- Reduction of thermal power plant capacity
- Thermal power plants change role to supplying power in fewer hours, reducing total ability to provide regulating power
- Larger overall power system (increased electrification)
- Option to provide regulating power to adjacent markets

Factors decreasing volume and/or prices

- Distribution of variable renewable energy across Europe can reduce system wide forecast errors and variations
- New suppliers of regulating power
- Increased flexibility in demand

Balancing prices are estimated assuming similar characteristics as today regarding correlations between spot and regulating power prices. With this background a number of synthetic prices series for regulating power prices are estimated. The price series are associated to the spot prices calculated from the Balmorel Model.

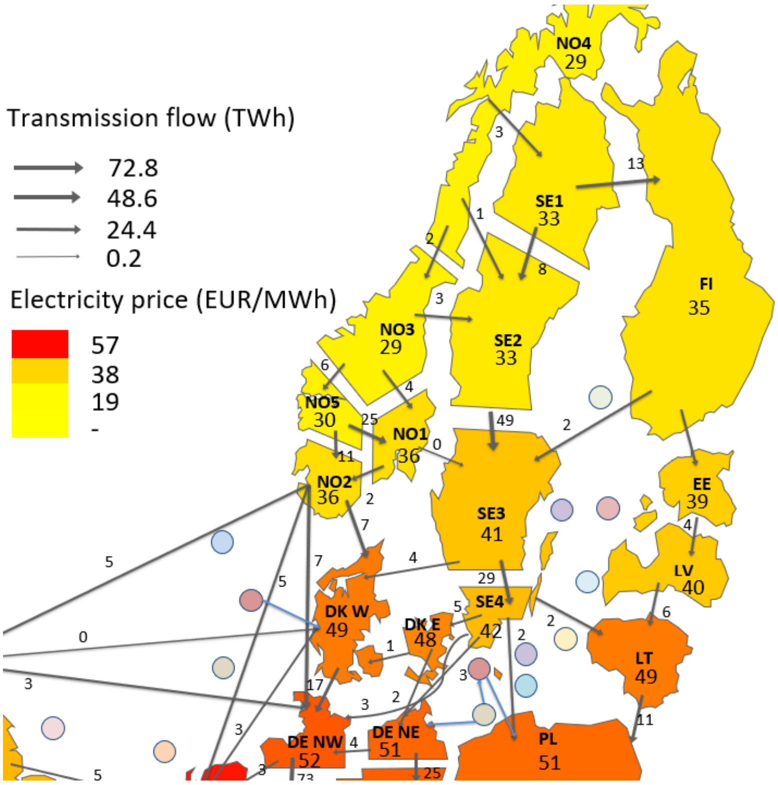
Assumptions behind the model are:

- Plant operates in blocks with price-foresight, e.g. 12 hours
- If a plant can retrieve start-up cost in block -> it operates
- Two points of operation allows the plant to react to price variations:
  - minimum load
  - maximum load
- Planned outages considered (derate factor)
- Seasonal variation in heat offtake considered for CHP (BP)
- If plant is active in spot market it can participate in down-regulation
  - if not active in spot market it can participate in up-regulation
    - up regulation is based on same concept but with 1-hour blocks

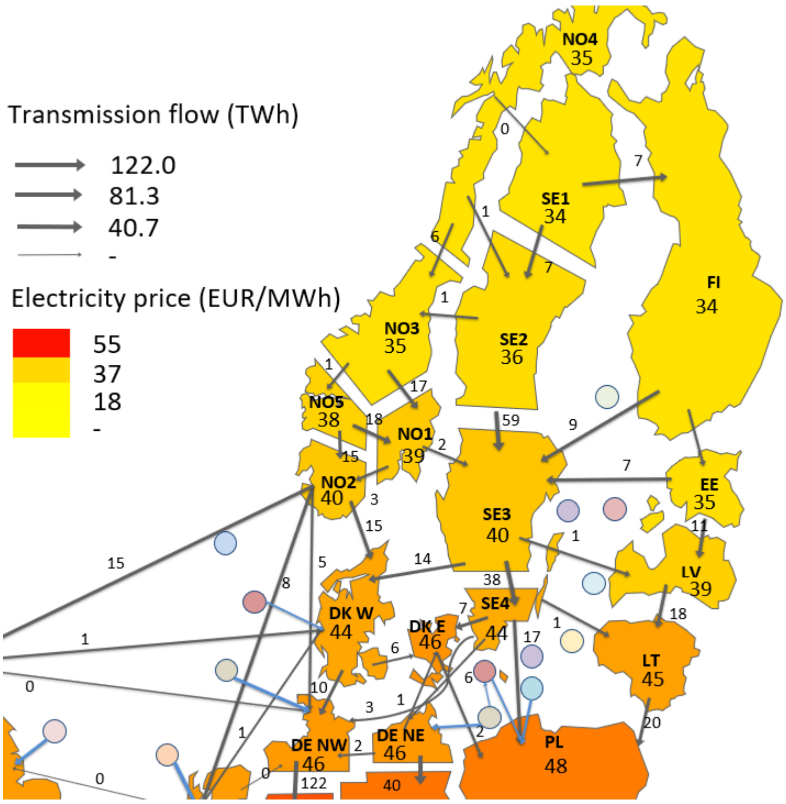
6.4 Geographical representation using maps

This section contains the geographical representation of model results using maps. The reference and NIMBY scenario are displayed for years 2030 and 2040. Maps contain both transmission flows between regions and the bidding zone electricity price in euro per MWh.

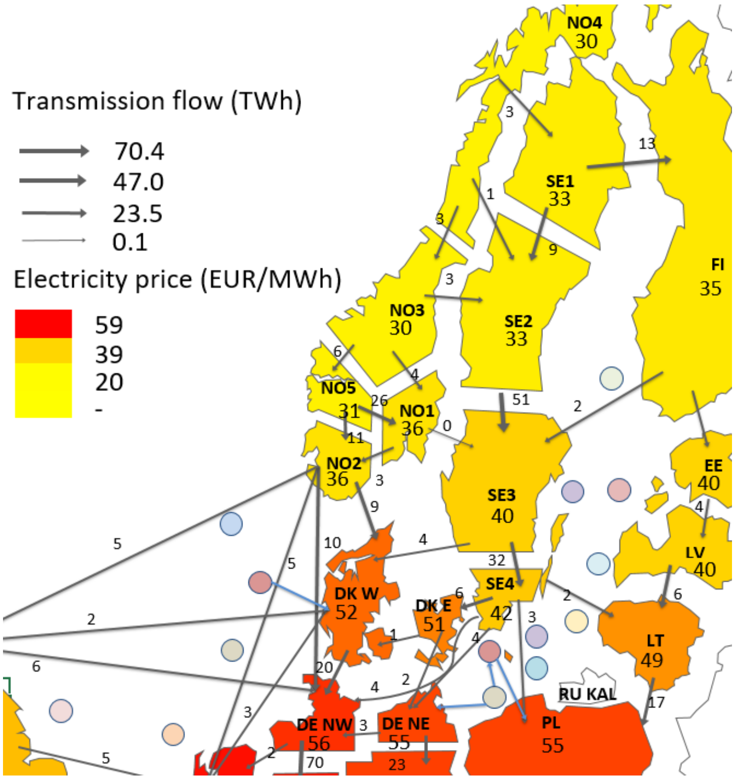
Reference scenario 2030



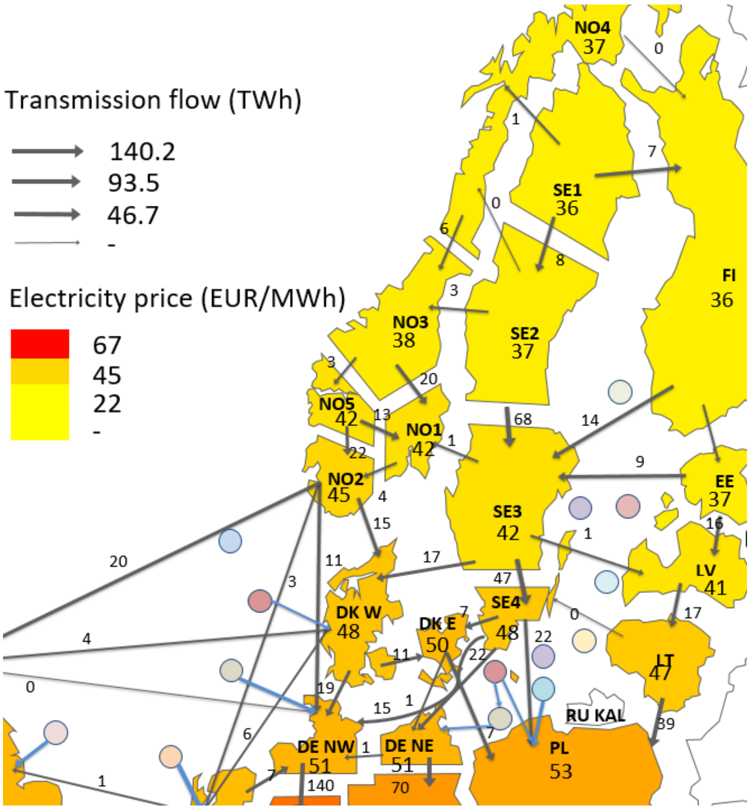
Reference scenario 2040



NIMBY 2030

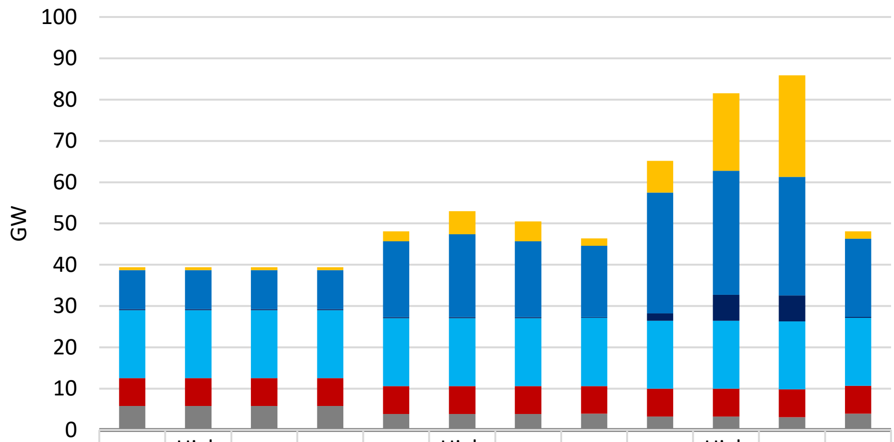


NIMBY 2040



6.5 Data table for power capacities

Sweden power capacity



	2020 Reference	2020 High_demand	2020 NIMBY	2020 Delayed	2030 Reference	2030 High_demand	2030 NIMBY	2030 Delayed	2040 Reference	2040 High_demand	2040 NIMBY	2040 Delayed
Solar PV	1	1	1	1	2	6	5	2	8	19	25	2
Wind Onshore	9	9	9	9	18	20	18	17	29	30	29	19
Wind Offshore	0	0	0	0	0	0	0	0	2	6	6	0
Hydro	16	16	16	16	16	16	16	16	16	16	16	16
Nuclear	7	7	7	7	7	7	7	7	7	7	7	7
Thermal	6	6	6	6	4	4	4	4	3	3	3	4