MASTER'S THESIS

MSc IN SUSTAINABLE ENERGY, ELECTRIC ENERGY SYSTEMS

Analysis of Socio-economic Potential for Power Storage in the Nordic Clean Energy Scenarios 2020 through Balmorel modelling

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February-2021

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Abstract
Power systems around the world are increasingly facing balancing issues due to increased integration of renewable energy sources. Flexibility measures are required to assist the transition from conventional power plants to renewable energy sources. Flexible consumption, storage capacity and transmission capacity between regions are competing measures of flexibility that can be utilized. This study investigates the potential of power storage in a highly competitive setting using the Balmorel model. The results show that power storage is competitive in multiple countries despite ambitious flexible electric vehicle consumption and transmission expansion being available. Results show that lithium-ion batteries are mainly competitive in Great Britain and Italy. Long-term high temperature thermal energy storage is shown to be competitive in Denmark, Sweden and Poland with total cycle durations of above 16 hours. However, endogenous storage investments prove to be sensitive to underlying Balmorel model assumptions regarding storage cycles in temporal aggregation.

Keywords: Energy Systems Analysis, Balmorel, Renewable Energy Integration, Flexibility Measures, Power Storage, High Temperature Thermal Energy Storage.

1 Introduction

In 2016, the Nordic countries, along with 195 other countries, signed the Paris Agreement which unified the nations of the world in the pursuit of keeping the increase of global temperature well below 2°C above pre-industrial levels [1]. Additionally, all efforts to limit the change to 1.5°C should be pursued as this would likely substantially reduce the risks and impact of climate change [1].

The power systems of the Nordic countries are undergoing a fundamental shift from traditional power plants towards renewable energy resources such as wind turbines and photo-voltaic panels (PV)[2]. The Nordic transportation sector has seen rapid growth in electric vehicles (EV) and plug-in hybrid vehicles (PHEV) sales. The result is a total Nordic EV and PHEV fleet reaching close to 500.000 vehicles in 2019 [2]. From the accelerated integration of renewables, arises an intermittency problem, due to the unpredictable nature of wind turbine and solar PV panel generation. There are many different approaches to handling this issue and many involve increasing the flexibility of the power system. Flexibility can be increased by strengthening inter-regional transmission connections, implementing flexible consumption measures, such as the utilization of existing EV battery capacity, through sector coupling or implementing storage capacity for peak shaving and valley filling. Analyses suggest that storage can provide an important interplay with intermittent power generation as suggested by the European-Commission and the Danish Energy Association [3][4].

This thesis will focus on the socio-economic[a] potential of power storage within the scope of the Nordic Clean Energy Scenario 2020 project (NCES2020).

[a]Socio-economics is the study of the economy as a whole contradictory to an individual perspective. Socio-economics involve both social and economic factors.

1.1 The Nordic Clean Energy Scenarios 2020

The NCES2020 project is a research study commissioned by Nordic Energy Research (NER) which serves under the Council of Nordic Ministers. The study serves the purpose of providing neutral and unbiased scientific analysis which will fuel political debate on pathways to decarbonizing the Nordic region. These pathways aim to limit global climate change to well below 2°C. The key objective is to examine the most cost-effective manners of reaching carbon neutrality.

1.2 Research Objective

This dissertation is carried out in collaboration with Ea Energy Analyses which has the leading Balmorel modelling role in the NCES2020 project. In this project, three different energy system scenarios are created and represents the foundation of further research objectives.

This thesis explores the potential of power storage integration of high temperature thermal energy storage (HTTES) and lithium-ion batteries on a utility-scale in the NCES2020 context. The NCES2020 pathways are utilized to obtain this objective as the three scenarios represent three different power system developments. This approach will provide insights into the energy system prerequisites needed for HTTES and lithium-ion battery integration. Additionally, the overall competitiveness of HTTES technology versus lithium-ion batteries is explored. Power storages are modelled to cover investment costs through arbitrage trading[a] in this thesis.

2 Methodology

This section presents the methodology applied in this thesis. The Balmorel model is applied for the analysis of scenarios and storage potential. An introduction to the model is presented in section 2.1. The flowchart in Figure 2.1 visualizes the methodology applied in this thesis. The base Balmorel model of Ea Energy Analysis is used as a foundation of the project. Updated input data from various sources, data calibration and area-aggregation of small Danish areas is implemented in the base model, shown in Figure 2.1. Additionally, HTTES technology modifications and data is applied. This leads to the NCES2020 and then the storage potential of HTTES technology and lithium-ion batteries. Lastly, a sensitivity analysis is conducted.

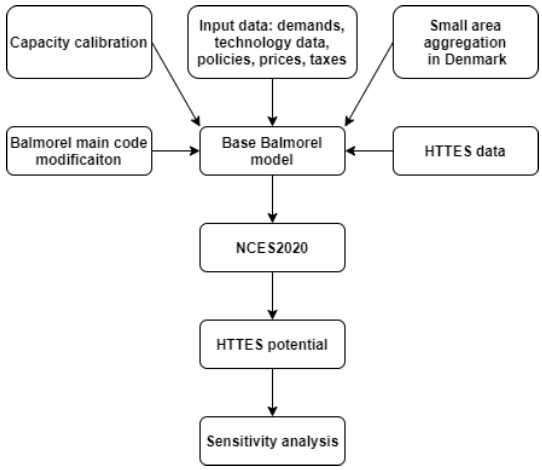

Figure 2.1: Flow chart of the applied methodology.

2.1 The Balmorel Model

The Balmorel Model is a partial-equilibrium model structured with a bottom-up perspective which is used for modelling and simulating power and district heating systems. 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 dissertation, 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 and Switzerland. There are four different model modes available in Balmorel. BB1 is an economic dispatch for one year. The economic dispatch operates unit generation through least-cost optimization which is called a unit commitment problem. This resembles that of real market conditions

[a] Arbitrage trading means taking advantage of price differences in a market. For example buying at a low price and selling at a high price.

as a merit order curve[a] is applied based on short-term marginal costs. This is applied to all regions and selected time segments. BB2 is an economic dispatch and capacity expansion for one year. Capacity expansion means that Balmorel will minimize the costs required to satisfy consumption in all regions and areas. For example, this can be done by adding or decommissioning unit capacity. The optimization is based on the total system costs of the whole model area. The capacity expansion and economic dispatch is performed iteratively to reach the optimum solution. BB3 is an economic dispatch for each season which is done iteratively. BB4 is an economic dispatch and capacity expansion for two or more years which allows investments to be based on a longer time perspective relative to BB2 mode. Further Balmorel description is in Appendix A.

All scenarios were analyzed using both BB2 and BB3 modes. BB2 capacity expansion and economic dispatch simulation require temporal aggregation to reduce computational time. The BB2 temporal aggregation applied is a resolution of 26 seasons and 12 time segments, simulating the years 2020, 2030, 2040 and 2050. As for BB3, the resolution was full-hourly with 52 seasons and 168 time segments per season for the years 2030, 2040 and 2050. The reason behind choosing the Balmorel model, to model the Nordic Clean Energy Scenarios and for investigating the storage potential, is because of its unique ability to simulate power and district heating markets and systems to a highly detailed degree. Additionally, the model is a widely acknowledged tool of energy system analysis research [5].

2.2 Competing Means of Flexibility

There are different types of flexibility measures available in the Balmorel model. These are the following:

- Dispatchable units.
- Storage.
  - Seasonal storage.
    - Heat pits.
    - P2X fuel storage.
    - Pumped hydro.
    - HTTES.
  - Short-term storage.
    - Lithium-ion batteries.
    - Short-term heat storage.
- Flexible Consumption.
  - P2X electricity consumption redistribution.
  - EV smart charging.
  - Demand response.
- Interregional transmission capacity.

These means are all in competition with eachother in terms of investment. They compliment eachother on a system level too. The seasonal storages can store power or heat in-between seasons while the short-term storages are intra-seasonal only. Flexible consumption are of different types. In this thesis, P2X electricity consumption redistribution allows for local regional-specific consumption to be shifted at a specified cost. The EV smart-charging flexible consumption acts as virtual storage were a part of the consumption can either increase, by charging outside natural pattern, or decrease by refraining from charging in the natural pattern. A specific fraction of the total EV capacity that can be used as virtual storage is assumed, shown in Appendix H. Interregional transmission capacity can provide indirect flexibility between regions as bottlenecks are minimized.

3 Data and Input

This section will present the major modifications and inputs to the Balmorel model. These are the following:

- Technology data regarding the HTTES technology will be shown in section 3.1.2.
- Lithium-ion battery technology data from the Technology Catalogue of Energy Storage from the Danish Energy Agency will be applied [6].
- Changes to the Balmorel main code will be shown in section 3.2
- Validation of storage representation in time-aggregated capacity expansion simulations will be addressed in section 3.3

Other model modifications are represented in Appendixes.

- An input overview of the applied data can be found in Appendix F
- Capacity calibration, represented in Appendix B
- Aggregation of Danish smaller district heating areas, represented in Appendix B.2

[a] A merit order curve is a ranking system of production units which is based on short-term marginal costs. The order is from low to high.

3.1 Technology Overview: High Temperature Thermal Energy Storage

3.1.1 Literature Review

HTTES technology is thermal storage which is a power-to-power storage. HTTES concepts have been under development in Denmark during the last decade. Several different configurations have been theorized, each configuration having some component differences. Different thermodynamic models of HTTES systems have been created in other dissertations, proving the theoretical feasibility of such systems[7][8]. The potential of a specific Rankine cycle based HTTES technology has been investigated in Balmorel before which resulted in 14.3 GW, 7.5 GW and 1 GW investments in Great Britain, Germany and Denmark respectively between years 2025 and 2035[7]. The storage replaced peaker gas turbines in the installed countries. As for practical feasibility, there are several HTTES pilot projects underway, as of 2020. One is a Siemens Gamesea project which applies an electric heater charge system and a conventional Rankine cycle for discharge [9].

The second is a DTU built thermal storage which applies an electric heater for charging and no discharge configuration [10]. As for the storage unit itself, different configurations of loading were investigated with a horizontal flow into layers of plates filled with diabase rocks. The study came across multiple challenges of charging the storage using horizontal flow. The end conclusion was that "In applications where thermal efficiency is critical, it will probably be advantageous to use a vertical flow configuration". This leads to the newest pilot project built at DTU which applies a vertical flow of charging the storage[11]. This dissertation will focus on a storage unit identical to the newest DTU project. The applied charge and discharge concept used is one developed by Stiesdal Storage Technologies(SST) which plans on building a prototype by 2022. SST has built a complete thermodynamic model in the software Engineering Equation Solver(EES) which simulates the thermodynamics behind storage charge and discharge, shown in Figure 3.1. This concept has three main differences from previous HTTES concepts.

- A reverse Brayton-Joule charge cycle and a Brayton-Joule discharge cycle is applied, explained in Section 3.1.2.
- The maximum temperature of the hot thermal storage is limited to 450°C. The majority of previous papers expected a 600 to 650°C thermal storage temperature [10], [7] [8]. This is the minimum limit temperature guaranteed by the actual turbomachinery manufacturer of the pilot project.
- Waste heat, otherwise lost to ambient air, can be utilized from the charge cycle. Other concepts will have featured the extraction of waste heat on the discharge cycle.

3.1.2 Applied HTTES Concept

The concept, used in this dissertation, applies a closed Brayton-Joule cycle when discharging and a reverse Brayton-Joule cycle when charging, using air as a medium. The system components are a compressor, a high temperature storage consisting of tanks filled with basalt rocks, a likewise low temperature storage, a turbine and a heat exchanger for cooling purposes.

An illustration of the system is shown in Figure 3.1. Blue and red trapezoids represent compressors and turbines respectively. Orange and blue tanks represent the hot and cold thermal storage respectively. When charging the storage, air is compressed to a high temperature through two compressors which are powered externally. The heated air is circumvented to the heat storage tanks and afterward cooled in the heat exchanger with the input cooling of a secondary closed system. The cooling source could potentially be the return pipe of a district heating system or another form of cooling. There is the potential to utilize heat at temperatures of approximately 95 °C down to 50 °C. The cooled air is expanded through a turbine to reach subzero temperature, and then circumvented to cool the cold storage tanks. The cycle is then repeated. Note that the charging principle is similar to that of a heat pump which explains a high efficiency of 330%, shown in Table 3.1. The discharge cycle starts by applying the cold storage to increase the discharging efficiency as the air can be cooled right before compression when discharging. The charging and discharging of the cold storage is proportional to the hot storage.

HTTES data			
Technical data \Years	30-39	40-49	50
η_{charge} [%]	330	330	330
$\eta_{discharge}$ [%]	17	17.5	18
CB-value	2.78	2.78	2.78
CAPEX power [M€-20/MW]	0.5	0.47	0.44
CAPEX volume [K€-20/MWh]	10	5	5
OPEX [k€-20/MW]	2.5	2.5	2.5
Stationary storage loss [%/hour]	0.1	0.1	0.1
Lifetime [years]	25	25	25

Table 3.1: Technical and economic HTTES data[12]

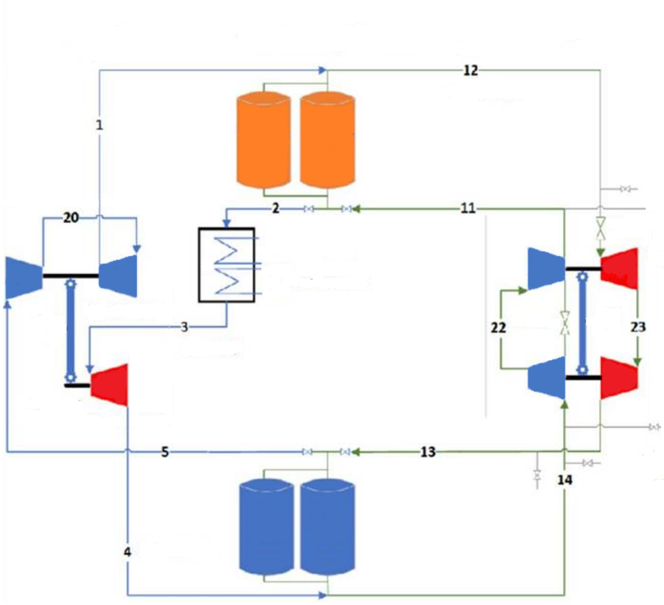

Figure 3.1: Schematic of the system components, blue marking the charge cycle and green marking the discharge cycle [12]

Compressed air is then circumvented to the hot storage for heating. Afterward, the air is expanded through the two turbines, generating power, and the cycle is repeated. Note that the two compressors are consuming some of the generated power in the discharge cycle. This results in a fairly low discharge efficiency of 16-17 percent, shown in Table 3.1. Gas turbine and compressed air energy storage(CAES) installations have similar components to the HTTES technology. The HTTES power capital expenditures, CAPEX, are projected to decline similar to that of regular gas turbines. The volume CAPEX is projected to decline due to economics of scale. HTTES power investment cost is comparable with gas turbines and CAES capital costs of 0.5-0.6 million €per MW [6][13]. The operating expenditures, OPEX, of the HTTES technology is based on OPEX estimates of CAES by the Danish Energy Agency estimates of 2.5 k€per MW in all years [6][14]. The storage is estimated to have a stationary loss of 0.1 percent of the energy content per hour. Appendix E contains further documentation of the HTTES technology.

3.2 Balmorel Modelling of Storage

Lithium-ion batteries are well represented in the Balmorel model with no need for modification. However, the current Balmorel version does not contain the specifications required for the direct implementation of the HTTES technology. For this reason, changes to the Balmorel main code is made. Two large modifications is represented in this section.

- Modification of storage volume equation.
- Allowed heat generation from power storage.

The HTTES technology is implemented so that the energy volume of the storage is equal to the thermal energy stored in the hot storage. Only the hot storage is modelled in Balmorel as the charge and discharge of the cold storage is proportional to that of the hot storage. All endogenous storage technologies are modelled using a Balmorel add-on which allows optimization of loading, unloading and volume capacities independently.

3.2.1 Volume Equation

First, the volume equation is modified to include stationary storage loss in the HTTES. This has not been needed before since other types of seasonal power storage, like pumped hydro, has no stationary loss. However, as the storage loss of the HTTES technology is 0.1 % per hour, this was deemed necessary to implement to simulate the real physical conditions. An example of the modifications in the volume equation is shown in bold in Equation 3.1.

$$Volume(Area, IGESTO_S, Season, Time\ step+1) = Volume(Area, IGESTO_S, Season, Time\ step) \boldsymbol{-(Volume(Area, IGESTO_S, Season, Time\ step) \cdot\ Loss(\%/hour) \cdot\ Length(Time\ step))} + Length(Time\ step) \cdot ((Loading(Area, IGESTO_S, Season, Time\ step) \cdot \boldsymbol{\eta_{Load}} - (Unloading(Area, IGESTO_S, Seasons, Time\ step) / \eta_{unload}))/Cyclesin(Season) \tag{3.1}$$

Where an area is the specified spatial layer, IGESTO_S is an internal set containing seasonal storage technologies, the season is the current season, the time step is the current time segment. A new loading efficiency is introduced by multiplying η(load) on the loading magnitude. The hourly loss is implemented by subtracting the current volume, as a function of area, IGESTO_S, season and time segment, multiplied with the percentage hourly loss and then multiplied with the length of the time segment. Multiple time segments are aggregated in BB2 capacity expansion simulations which makes the length of the time segment vary as it can be as many as 80 hours in some time segments. Details of the volume equation is presented in Appendix C.1.

Lastly, loading and unloading magnitudes are divided by the parameter cyclesin in Equation 3.1 which is the assumed number of cycles per season. This parameter is inserted only in BB2 capacity expansion simulations to compensate storage units because time-aggregation heavily limits arbitrage trading opportunities of a storage on a yearly basis. 8,736 hours are aggregated into 312 time segments and price differences within these 312 time segments cannot be utilized. Cyclesin provides storage units with additional artificial volume capacity as the loading and unloading magnitudes are divided with a value above 1 to simulate cycles within each time segment. Cyclesin is only applied in volume equations and does not affect the system-perspective loading and unloading capacity of a storage.

3.3 Validation of Cyclesin Value

The cyclesin value of 8 is applied in the Ea Energy Analyses base model. However, a comparison between time-aggregated BB2 and full-year BB3 simulations showed a large mismatch between storage electricity generation. Especially lithium-ion batteries showed a large generation mismatch which needed to be adjusted as not to over-represent this type of storage. Figure 3.2 shows the average relative difference in electricity generation from endogenous storage investments between BB2 capacity expansion simulations and full-year BB3 simulations as a function of cyclesin value.

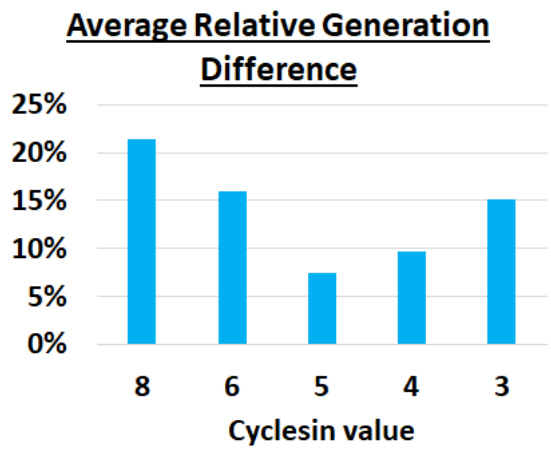

Figure 3.2: Average relative difference in storage electricity generation between BB2 and BB3 as function of cyclesin value.

The Figure shows that a cyclesin value of 5 results in the lowest average relative generation difference between time-aggregated and full-year model simulations. This value is applied in further model simulations.

3.3.1 Allowing Heat Generation

The HTTES technology can generate heat when loading which is unlike any technology type implemented in Balmorel. This required several modifications in the Balmorel main code. The main modification was to create an equation that limits the heat generation of the HTTES technology using the CB-value, similar to conventional backpressure co-generation plants. This is shown in Equation 3.2.

$$Loading(Area, IGEHSTO, Season, Time\ step) = Heat_{gen}(Area, IGEHSTO, Season, Time\ step) \cdot CB \tag{3.2}$$

Where area is the specified spatial layer, IGEHSTO is an internal set containing HTTES technologies, season is the current season, time step is the time segment.

A more detailed documentation of modifications regarding allowing heat generation is presented in Appendix C.2. Model input changes concerning the HTTES technology implementation are documented in Appendix D.

3.4 Nordic Clean Energy Scenarios 2020

The **Carbon Neutral Nordic (CNN)** scenario is a pathway of which the Nordic countries reach carbon neutrality through the current national plans. Current electrification projections are used for heating, transport and industry. Main assumptions are:

- P2X[a] electricity consumption has to be satisfied locally in each country.
- Inter-regional transmission expansion limitation to 1,500 MW per 5 years.
- Potentials of onshore wind turbines in the Nordic countries is limited due to high assumed local resistance to onshore turbines.

The **Nordic Powerhouse (NPH)** scenario is a pathway of which the Nordic countries reach carbon neutrality through the current national plans. Additionally, the Nordic countries will function as a powerhouse to central Europe which can provide cheap electricity for industry and electrofuels. The model will have the option of redistributing electrofuel, P2X, electricity consumption in one country to another country at a cost of 10 € per MWh fuel. All electrofuel demand is modelled to be a flat demand with no variations as a function of time. Main assumptions are:

- P2X redistribution option, 10 €-19 per MWh fuel.
- Increased inter-regional transmission expansion limitation to 3,000 MW per 5 years.
- Higher onshore wind turbine potentials in Nordic countries, local resistance to onshore turbines is assumed low.

The **Nordic powerhouse + (NPH+)** scenario is equal to the NPH scenario but with a decrease in capital costs of 5%, 15% and 25% of offshore wind power technologies in 2030, 2040 and 2050. This scenario is created to see the effect of reduced offshore turbine costs.

A model area biomass consumption constraint of 2,537 PJ per year is applied in all scenarios to maintain reasonable levels of consumption, documented in Appendix G.

4 Scenario Findings

The scenario findings is presented in this section.

4.1 Electricity Consumption

The applied electricity consumption in the scenarios is based on the European Commission COMBO scenario [15]. The modelled countries in Balmorel are named EU18[b]. The scenario shows to what extent green house gas emissions can be reduced by current technological solutions and options. The scenario reaches a 90 percent green house gas emissions reduction in 2050 compared to 1990, thereby addressing the well below 2°C ambition. Figure 4.1 shows the development of classical, P2X, EV, district heating, individual heating and industry electricity consumption in EU18 countries.

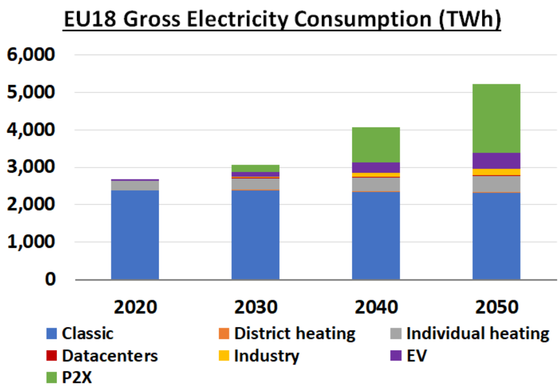

Figure 4.1: Electricity consumption of the EU18 countries COMBO Scenario

The classical consumption is expected to be fairly constant as growth and energy savings roughly cancel out with the consumption being 2,374 TWh in 2020 and 2,319 TWh in 2050. The EU Commission is expecting significant increases of P2X electricity consumption of 192 TWh in 2030, 933 TWh in 2040 and 1,828 TWh in 2050. EV consumption, individual heating consumption and industry consumption are expected to reach 425, 449 and 155 TWh, respectively, in 2050.

[a] Power-to-X (P2X), in this research, includes all electrofuels including hydrogen, meaning all fuels produced by electricity.

[b] The EU18 countries include Austria, Belgium, Czech Republic, Denmark, Estonia, France, Finland, Germany, Great Britain, Latvia, Lithuania, Luxembourg, Netherlands, Norway, Poland, Sweden, Switzerland.

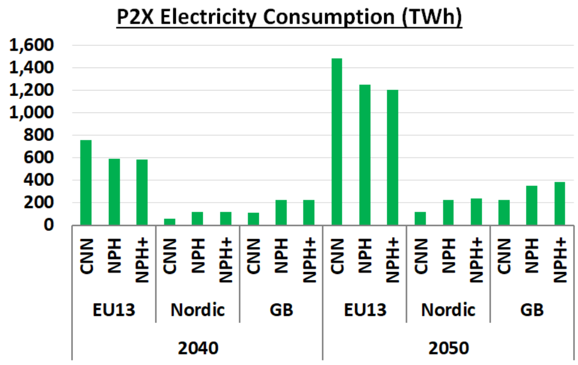

Figure 4.2: P2X electricity consumption.

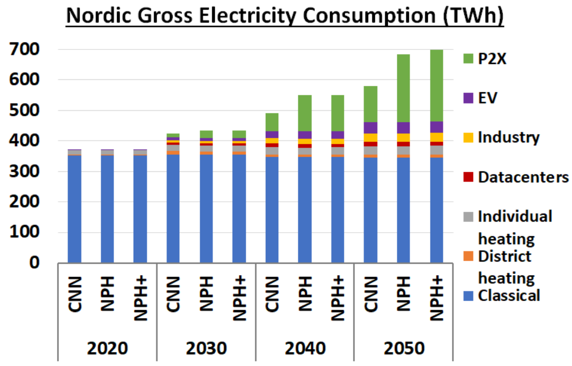

Figure 4.3: Nordic electricity consumption.

The district heating electricity consumption is projected to have a modest development from 2 TWh in 2020 to 14 TWh in 2050. These significant consumption increases towards 2050 combined with a need for energy transition to renewable energy sources will require a heavy build-out across Europe. The key to understanding the difference between the CNN and NPH scenarios is to understand the redistribution option of P2X electricity consumption between countries. The P2X consumption is a flat consumption profile and can be shifted between countries at a penalty cost of 10 € per MWh fuel in the NPH and NPH+ scenario. In the CNN scenario, the P2X electricity consumption must be fulfilled locally.

Figure 4.3 shows how the P2X electricity consumption is shifted from continental Europe to the Nordic countries and Great Britain in 2040 and 2050. In the NPH scenario in 2040, 60 TWh P2X electricity consumption is shifted to the Nordics, increasing the total consumption to 120 TWh. The shifted consumption from continental Europe to the Nordics becomes 117 TWh in 2050. Figure 4.2 shows how the total Nordic consumption changes in the CNN, NPH and NPH+ scenarios respectively. The Figure shows the magnitude of increase in the total Nordic electricity consumption, as the total Nordic electricity consumption is increased by 12% in 2040 in the NPH scenario and by 20% in 2050. Great Britain also experience a shift in P2X electricity consumption as 113 TWh is added in the NPH scenario in 2040 and a total of 130 TWh in 2050, seen in Figure 4.3. This indicates a strong incentive to move P2X electricity consumption to the Nordic countries and Great Britain due to favorable conditions. The NPH+ scenario show additional P2X electricity consumption increases.

4.2 Development in the Model Area, EU18

The scenario-specific model area power capacities are shown in Figure 4.4. Figure 4.4 shows similar results in all scenarios in 2020, 2030 and 2040 with an extensive

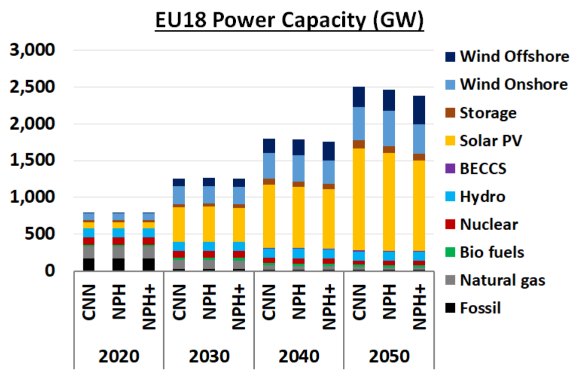

Figure 4.4: Model area power capacity development in each scenario.

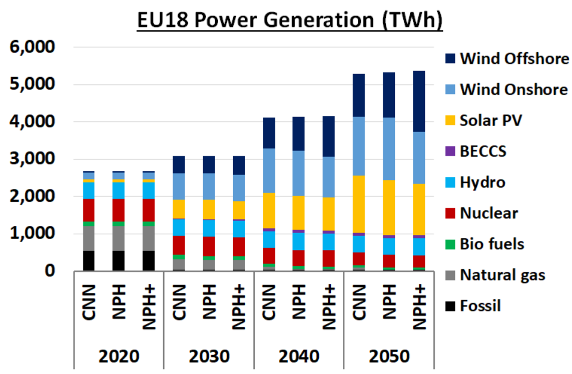

Figure 4.5: Model area electricity generation development in each scenario.

build-out in solar PV, onshore and offshore wind power. Averagely 460 GW of solar, 240 onshore wind power and 110 offshore wind power is installed in 2030. These replace fossil related capacity where 130 GW is decommissioned in 2030. Figure 4.5 shows the generation perspective where 500 TWh fossil-based generation and 380 TWh of natural gas-based generation is replaced in 2030 in all scenarios. This early phaseout can mainly be explained by the high CO_2-prices applied from the Sustainable Development scenario which states a price of 79 € per ton in 2030, which is a very high expenditure of fossil related generation [16]. Further increases in renewables is shown in years 2040 and 2050, shown in Figure 4.4, due to increases in P2X electricity consumption, shown in Figure 4.1, and increasing CO_2-prices. In Figure 4.4, the NPH+ scenario shows a different tendency as reduced offshore prices result in higher expansion degrees of offshore turbines across Europe in 2040 with 257 GW installed against 194 GW in CNN and 214 in NPH. Figure 4.5 shows that the high full load hours of offshore wind compensate for the decreased overall capacity of the NPH+ scenario in 2040 as less solar PV and onshore wind turbines are applied in the scenario.

The flexible EV consumption is behind a major flexibility in the scenarios. This flexibility is obtained from lowering or increasing consumption to replace real generation. The effect of this operation is quite significant on a system level as it corresponds to a large magnitude of generation. This magnitude is 38 TWh in 2030, 123 TWh in 2040 and 240 TWh in 2050 in the EU18 model area.

The effect of allowing P2X electricity consumption redistribution is not apparent before 2050 in Figure 4.4. However, there are differences in capacity in regions where consumption is shifted to or away from. These will now be presented.

4.3 Development in the Nordics

Figure 4.6 shows the Nordic power capacity in 2040 where an additional 15 GW of onshore wind power is installed in the NPH scenario in 2040. The difference is due to a 8 GW capacity increase in Norway, 2 GW in Sweden and a 5 GW increase in Finland which has higher Nordic onshore turbine potentials in the NPH scenario relative to the CNN scenario. This corrsponds to the increase in onshore turbines on a European level in Figure 4.4 between CNN and NPH scenarios.

In Figure 4.4, the NPH scenario has an increase of 25 GW onshore wind power across Europe with respect to the CNN scenario in 2040. The onshore shift can largely be explained by Figure 4.6 which shows a 25 GW increase in onshore wind between CNN and NPH scenarios in 2050 in the Nordics. All Nordic countries, except Finland, install their maximum onshore potential in the CNN scenario in 2050 which contains more conservative onshore potentials. The NPH and NPH+ scenario contain higher potentials which are exploited as onshore wind is favored to a higher degree than solar PV and offshore wind power. The Nordics experience a decrease of 11 GW in offshore capacity in the NPH scenario as capacity in the Norwegian and Swedish areas is reduced due to the availability of additional onshore wind power.

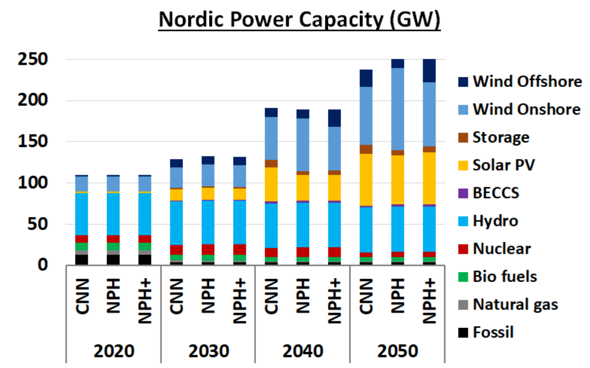

Figure 4.6: Nordic power capacities in each scenario.

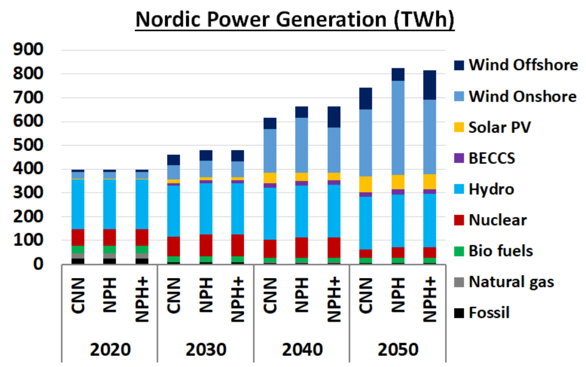

Figure 4.7: Nordic power generation in each scenario.

In the NPH+ scenario in 2050, Figure 4.6 shows that the total Nordic offshore wind capacity is increased by 16 GW and the onshore wind capacity is decreased 21 GW relative to the NPH scenario as offshore prices are more competitive with onshore turbines. However, even with a 25% reduction in 2050 in offshore capital costs, onshore turbines are still, by far, the main renewable resource utilized in the Nordics due to competitive average wind speeds and full load hours.

4.4 North Sea Offshore Turbine Development

In Figure 4.4, the increase in total European offshore between CNN and NPH/NPH+ scenarios is mostly due to increases in British and Dutch North Sea areas, shown in Figure 4.8. This increase is due to P2X elecricitt consumption shifting as 130 TWh P2X power demand is shifted to Great Britain from continental Europe between the CNN and NPH scenario in 2050.

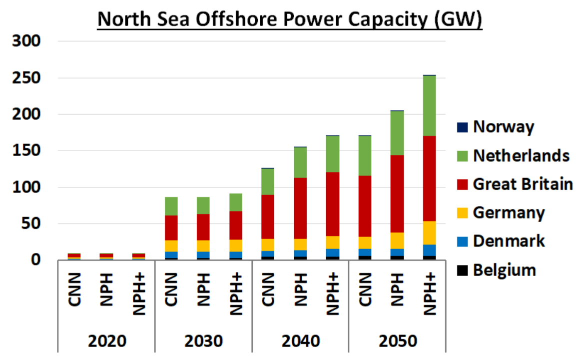

Figure 4.8: Offshore capacity in the North Sea.

Interestingly, the NPH sceneraio show added investments in British and Dutch offshore areas in 2040 and 2050 when one would think that Denmark, Norway and Germany have roughly the same conditions. The reason is that some British and Dutch areas have a slight advantage in average wind speeds in areas that are in the medium distance to shore category.

4.5 2050 Electricity Consumption

Figure 4.9 shows the magnitude of gross electricity consumption in Great Britain, among other selected countries, which is one of the reasons behind the significant offshore turbine capacity expansion in Figure 4.8. Additionally, Figure 4.9 shows that the P2X electricity consumption is mainly shifted from South Germany, called DE_CS, and Italy, in the NPH and NPH+ scenarios, to Great Britain and the Nordic regions. Interestingly, the NPH+ scenario shows that the Netherlands and Great Britain have increased P2X electricity consumption relative to the NPH scenario. A decrease in offshore prices would thereby allow even more P2X electricity consumption to be shifted from South Germany.

The reason behind the shift from South Germany is because the region contains a high electricity consumption compared to onshore turbine and solar PV potentials. All onshore turbine and solar PV potential in the South German region are utilized in all scenarios and years. This makes the region dependent on electricity import to supply the high consumption, due to the large population which is located in the region, shown in Figure 4.9. Similar arguments apply to Italy which also deploys all onshore turbine and solar PV potential in all scenarios and years. However, Italy contains offshore potential but the Mediterranean Sea generally offers fewer full load hours compared to the North Sea.

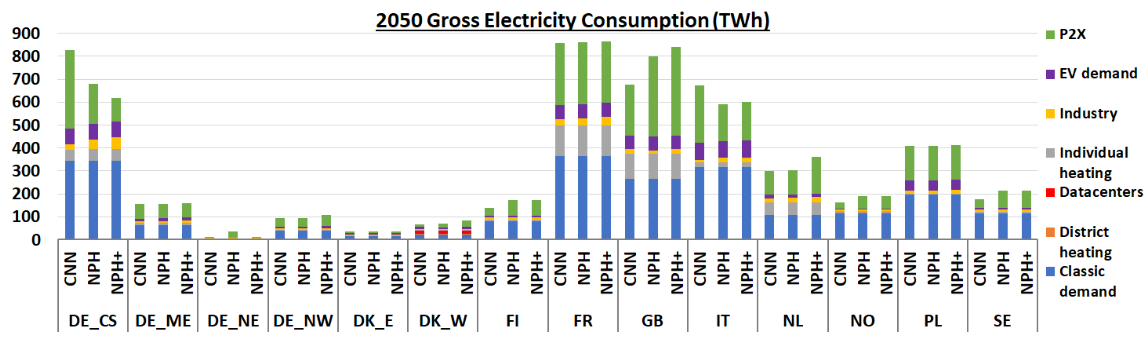

Figure 4.9: 2050 regional gross electricity consumption of selected regions. Regional nomenclature is in Appendix N.

4.6 Objective Function

In the end, the objective function is reduced from 276.5 billion € in the CNN scenario to 271.5 billion € in the NPH scenario in 2050 which is a 2 percent reduction. This is due to the redistribution of P2X electricity consumption, increased transmission expansion possibilities and increased Nordic onshore wind potentials. The socio-economic value of these changes is thereby 5 billion € in 2050.

5 Storage Findings

This section will present the storage results.

5.1 Lithium-ion Battery Investments

Figure 5.1 and 5.2 shows the installed lithium-ion battery power and volume capacities of each scenario and year. The Figures show that battery capacity is mainly installed in Great Britain, Poland and Italy. The CNN scenario shows a larger magnitude of investment of unloading capacity and volume capacity relative to the other two. The CNN scenario is the least flexible of the three which makes it the most attractive scenario for storage investments. The reason behind storage capacity installed Poland and Sweden is due to a demand for export to neighboring German regions in the CNN scenario. The German regions require import because local P2X consumption cannot be redistributed in the CNN scenario. This is further explained in Appendix I.2

The highest magnitude of battery investment is in Great Britain in 2050. The country has a relatively large installed capacity of all renewable energy sources and a relatively small share of dispatchable units in that year. 11 GW nuclear, 4 GW biomass and 2 GW hydro units are operational while all fossil-fired units are phased out in 2050. A demand for dispatchable power capacity arises to satisfy the hourly demand which reaches 63 GW in peak hours. Italy remains largely unaffected in NPH and NPH+ scenarios as there is little change in the fundamental power system between scenarios. Reasons for battery investment in Italy could be that solar PV is a very fluctuating energy resource which is a good combination to short-term storages such as lithium-ion batteries. This combination has also been observed to be attractive in other studies [4][17].

5.2 HTTES Technology Investments

The HTTES technology investments are shown in Figure 5.3 and 5.4. Investments in power capacity are limited compared to lithium-ion batteries due to the high power investment costs per MW. However, volume capacity investments show magnitudes which is comparable to lithium-ion battery volumes. This shows a high volume to power ratio of HTTES investments. Unlike the lithium-ion battery investments, the HTTES investment in Poland magnitude does not vary significantly between the three scenarios. In Poland in the NPH and NPH+ scenario, HTTES capacity is slightly increased while lithium-ion battery capacity is phased out. HTTES investments in Denmark and Poland only occur in 2030. The existing power capacity in Poland 2020 consists largely of coal-fired power plants and only 0.5 GW natural gas units.

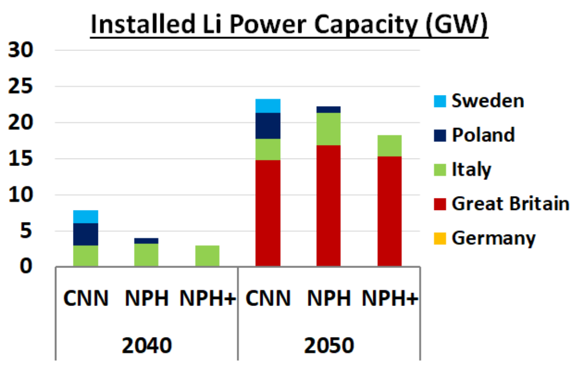

Figure 5.1: Power capacity of lithium-ion batteries.

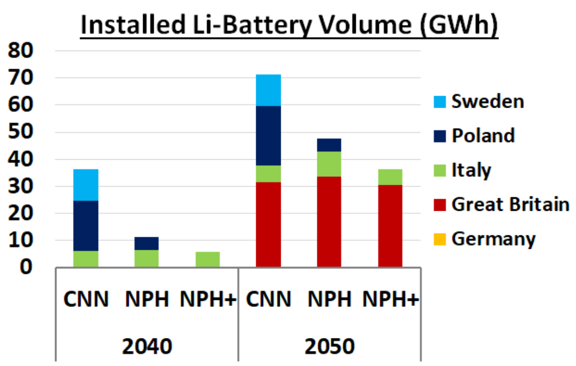

Figure 5.2: Energy volume of lithium-ion batteries.

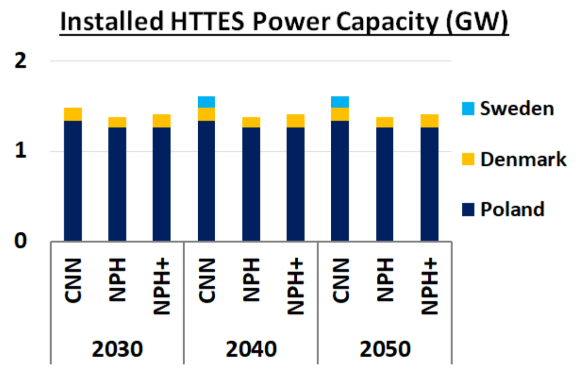

Figure 5.3: Power capacity of HTTES technology.

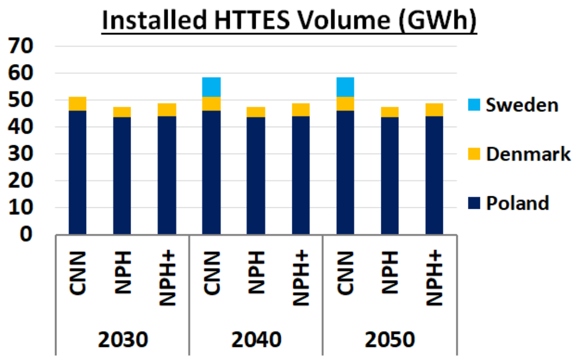

Figure 5.4: Energy capacity of HTTES technology.

2 GW of additional natural gas unit capacity is installed in 2030 but the majority of investments in future years are in renewables. Additionally, Poland plans to commission new nuclear capacity of which 3 GW is installed in 2033 and 3 additional GW in 2039 which can cover baseload needs[18].

5.3 Storage Investment Cost Comparison

The following cost comparison will analyze the cost-competitiveness of lithium-ion batteries versus HTTES and why investments, in both technologies, are present in Sweden and Poland. The main modelling difference between lithium-ion battery technology and HTTES technology is in the loading and unloading efficiency. The lithium-battery model setup is quite simple as it is assumed to have a 100 percent loading efficiency and a 92 percent unloading efficiency. On the other hand, the HTTES technology has a 330 percent loading efficiency and a 17-18 percent unloading efficiency depending on the year. The impact of efficiency is important to understand because it means that, to achieve the same power output capacity as lithium-ion batteries, the HTTES storage volume needs to be 1/0.17 or 5.9 times larger due to the discharge efficiency, shown in Table 5.1.

The larger volume needed also affects the loading capacity needed to equal a specific lithium-ion battery loading duration. The loading capacity should thereby be divided by the loading efficiency of 330 percent but also multiplied by 5.9 to have an equivalent loading duration. All in all, this is a disadvantage to the HTTES technology as the required higher volume capacity and loading capacity equal higher costs. However, the HTTES volume investment costs are significantly lower than lithium-ion battery costs. HTTES MWh costs are only 5-7 percent that of lithium-ion battery costs from 2030-2050.

Example of 2 hour loading and unloading duration		
	Lithium-ion battery	**Equivalent HTTES**
Unloading capacity (MW)	0.5	0.5
Storage volume (MWh)	1.1	5.9
Loading capacity (MW)	0.55	0.9

Table 5.1: Example of lithium-ion battery equivalent HTTES capacities.

The significantly lower HTTES volume cost is reflected in Figure 5.5 which shows 2030 investment costs per MWh volume at different unloading durations. The Figure shows how HTTES and battery investment costs per MWh decreases as a function of higher cycle durations. The HTTES technology becomes cost-competitive to lithium-ion battery investment costs at 8 hours of unloading time. The HTTES investment costs, in Figure 5.5, include the costs of higher volume and loading capacity required to make a lithium-ion battery equivalent. However, lithium-ion volume costs are projected to rapidly decline, at a faster pace than HTTES volume costs. Figure 5.6 shows that lithium-ion batteries will be competitive to HTTES technology at up til 16 hours of unloading duration in 2050. The lithium-ion battery cost-competitiveness of years 2040 and 2050 is reflected by investment in Figure 5.2 and 5.1.

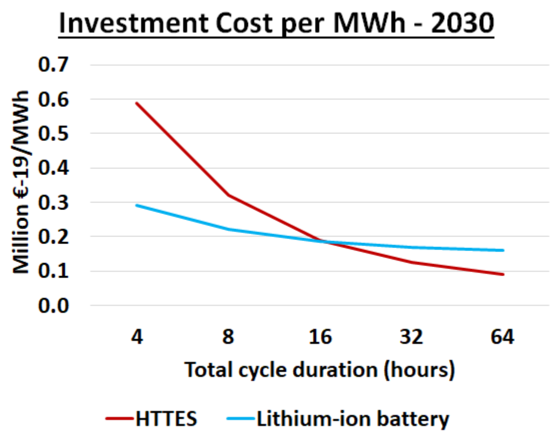

Figure 5.5: Investment costs per MWh as a function of total cycle duration. Loading and unloading durations are equal.

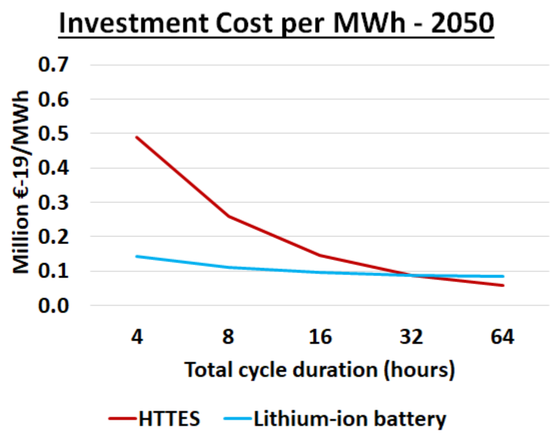

Figure 5.6: Investment costs per MWh as a function of total cycle duration. Loading and unloading durations are equal.

5.4 Optimized Loading and Unloading Durations

The model have the opportunity to optimize storage loading, unloading and volume capacity independently. Figure 5.7 show the loading and unloading durations of storage investments. HTTES investments in Poland, Sweden and Denmark show high loading and unloading durations. This reflects the investment cost curves of Figure 5.5 as HTTES investments have above 16 hours of total cycle duration. HTTES capacity in Poland shows that loading duration is significantly increased compared to unloading duration. This indicates a cost trade-off of having less loading capacity to maximize unloading capacity. All other storage investments show a roughly linear relationship between loading and unloading duration. Lithium-ion batteries are applied at loading and unloading durations of 2 hours in Great Britain and Italy while investments in Poland and Sweden show higher durations of 6 hours. Figure 5.1 and 5.3 show capacity investments of both technologies in Sweden and Poland. The loading and unloading durations of batteries and HTTES in Sweden are particularly close. These durations approach the intersection between HTTES and lithium-ion battery costs as shown in Figure 5.5 where investment costs per MWh are equal. This potentially means that changes in investment costs or other parameter changes could flip the scales in either direction, resulting in only one storage technology being applied.

5.5 2030 Electricity Prices

Storage technologies cover their investment costs by performing arbitrage tradingn in a market. The difference in electricity prices in a region is a key factor in the feasibility of storage technology. Figure 5.8 shows

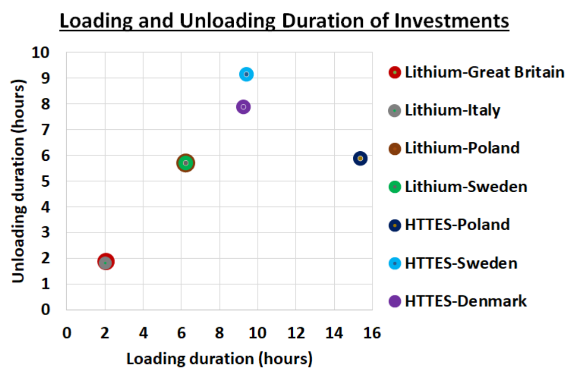

Figure 5.7: Optimized loading and unloading durations of storage investments. These are equal across scenarios.

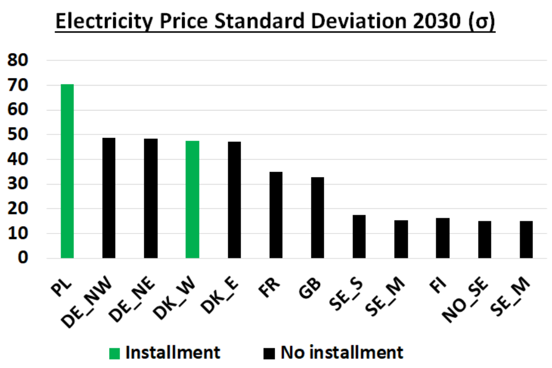

Figure 5.8: Electricity price standard deviation in selected regions in CNN scenario 2030.

the electricity price standard deviation in selected regions. The Figure shows that Poland has a relatively high deviation from the average price compared to other regions. The Western Denmark region, DK_W, contains a high price deviation but the limited investments in Figure 5.3 reflect that the prerequisites are border-lining to no investment. Be aware that price standard deviation does not reflect the chronology of a price profile which is an important aspect to arbitrage trading.

5.6 Storage Capacity Optimization

A description of how Balmorel optimizes storage capacity is presented in this section. Balmorel optimizes all unit capacity so that BB2 annual revenues are equal or lager than annualized costs. The revenues of a storage are determined through arbitrage trading value in a market. Balmorel installs storage capacity if the differences in electricity prices between time segments yield an annual revenue that can cover the annualized costs. Storage capacity is thereby added until an equilibrium between annual revenue and costs is formed. This means that storage capacity is primarily optimized according to the time segment which contain very high prices as these yield a high revenue.

One can argue whether or not this methodology is valid as storage revenue is fully optimized which would be challenging to do in reality. As storage capacity is optimized based on BB2 prices, a revenue mismatch can occur relative to BB3 simulation because electricity price magnitude and profiles can vary between the two simulations. Optimized storage capacity according to BB2 prices might not be optimal relative to BB3 prices. The previously mentioned cyclesin parameter plays a crucial role in the BB2 capacity optimization. The usage of this parameter adds artificial volume capacity to a storage unit as loading and unloading magnitudes are divided by the cyclesin value. In this thesis, a cyclesin value of five is applied. From a system perspective, the storage volume is effectively five larger to compensate for time-aggregation in BB2 simulation. Without compensation, storage investments are not feasible.

5.7 Example of the Impact of Cyclesin Application

This section presents the impact of cyclesin application, see volume Equation C.2, which is applied in BB2 simulation and not in BB3. Figure 5.9 shows an HTTES storage cycle in Poland during the highest price duration where the electricity price reaches 946 € per MWh for 30 hours. The Figure shows that the volume and unloading capacity is optimized to perfectly match the duration of the high price hours. Note that the length of the aggregated time segments S24-T010 and S24-T011 is 30 hours. Figure 5.10 shows a storage cycle in BB3 during peak price hours which has the same duration of 30 hours as in BB2 in Figure 5.9.

However, the HTTES storage volume in the BB3 simulation is not large enough to fully exploit the total duration of these high prices as cyclesin is not applied in the BB3 simulation. The maximum volume capacity in BB3 simulation is thereby reduced. Note that the total volume in Figure 5.9 is five times larger than in Figure 5.10 due to the usage of cyclesin. Additionally, this

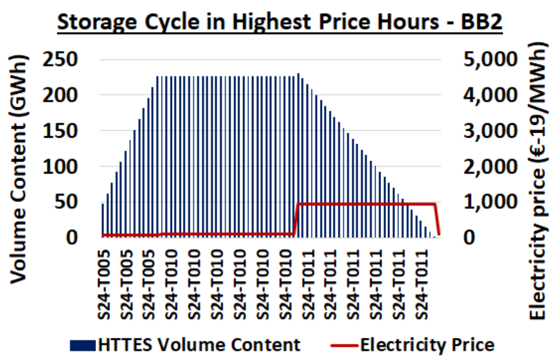

Figure 5.9: BB2 HTTES storage operation in Poland, CNN 2030. Time segments are disaggregated.

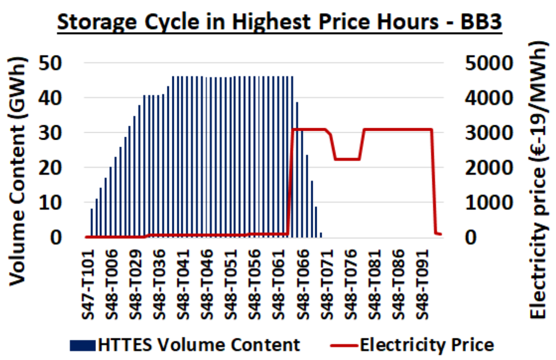

Figure 5.10: BB3 HTTES storage operation in the highest duration of extremely high prices in Poland, CNN 2030.

makes optimized BB2 loading and unloading durations different to real durations which is present in BB3 simulations. This is an issue as the HTTES technology is potentially underrepresented in full-year BB3 simulations due to its very low volume investment costs.

5.8 HTTES Operation and Profit in BB2 and BB3

Figure 5.11 shows the HTTES storage operation in Poland 2030 in the BB2 simulation. The Figure shows the loaded storage volume and accumulated electricity sales profit throughout the year. Note that the x-axis shows the aggregated time segments of the BB2 simulation and that artificial volume capacity obtained through cyclesin usage is included in the y-axis. Additionally, charging costs are included in electricity sales profit. The profit of the storage in Poland shows that the majority of its profit from electricity sales are earned in extremely high price hours around hour 70 and 277. In practice, this is difficult to realize.

Figure 5.12 shows the same operation as Figure 5.11 but with respect to the HTTES storage in Denmark. The Figure shows that the HTTES technology in Denmark is less dependent on profit from extremely high prices as 35 percent of the total electricity sales profit is earned around hour 70. Figure 5.13 shows BB3 results of full-year HTTES operation in Poland. The Figure shows that 23 million € a year is earned outside extremely high price hours which is around the same level as Figure 5.11. However, the total charging cost of BB2 operation is 44 million € a year while BB3 charging cost are 23 million € a year. This indicates larger local optimization flexibility in the BB3 simulation due to full-year resolution. An overview of charging costs can be seen in Appendix Figure L.2. However, profit from extreme price hours is reduced in the BB3 simulation.

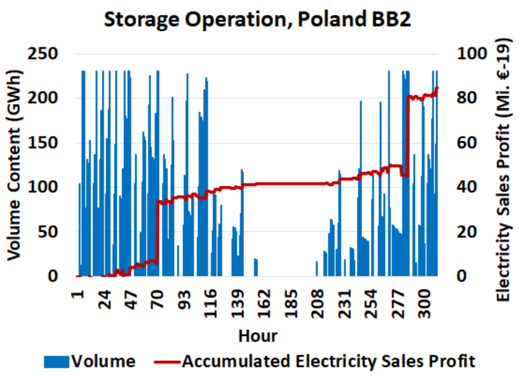

Figure 5.11: HTTES operation on installed capacity in Poland in 2030 from BB2 results.

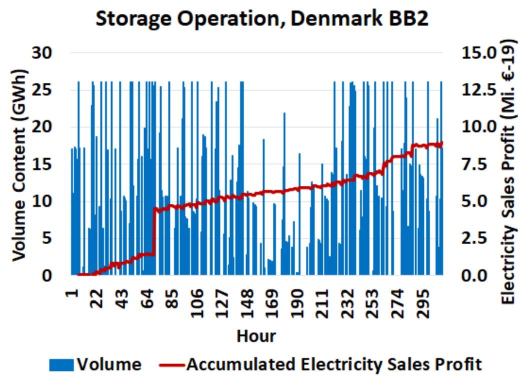

Figure 5.12: HTTES operation on installed capacity in Denmark in 2030 from BB2 results.

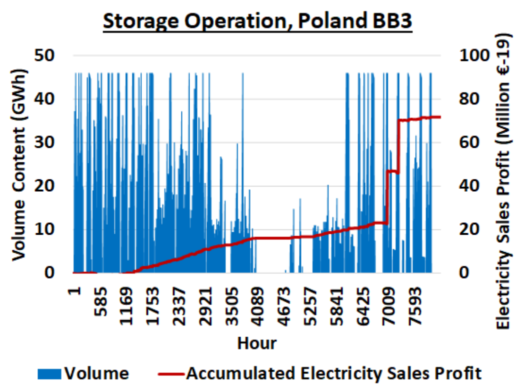

Figure 5.13: HTTES operation on installed capacity in Poland in 2030 from BB3 results.

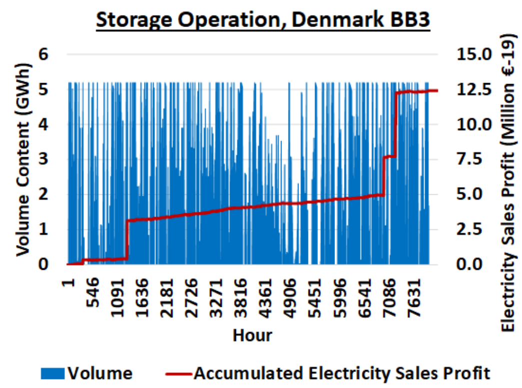

Figure 5.14: HTTES operation on installed capacity in Denmark in 2030 from BB3 results.

This results in a 72 million € yearly BB3 profit in Poland compared to 85 million € a year in BB2 simulation. Oppositely, HTTES operation in Denmark in Figure 5.14 show that the BB3 simulation results in a higher annual profit of 12.5 million € compared to 9 million € in the BB2 simulation. The reason behind the increase is due to a higher profit from extremely high price hours as shown in Figure 5.14. This means that the HTTES capacity in Poland is overrepresented in the full-year BB3 simulation as the profit is 15 percent reduced while the HTTES capacity in Denmark is underrepresented as the BB3 profit is 30 percent increased.

5.9 100 Highest Prices in Poland and Denmark W

Figure 5.15 show that the HTTES investments in Poland should be able to have a higher profit using BB3 prices as there is a significant number of hours with a higher electricity price equal to 3,000 €.

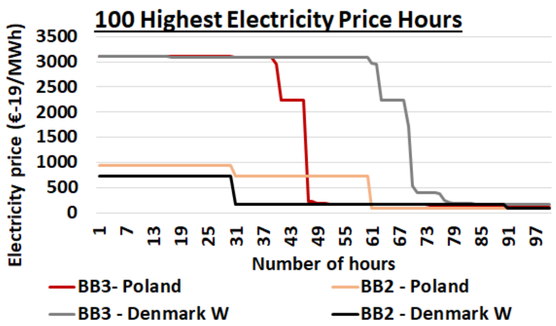

Figure 5.15: 100 highest electricity price hours in Western Denmark and Poland.

However, as Figure 5.10 shows, many of the highest price hours are connected in series. This poses a problem in BB3 simulation as the volume capacity is lower without the usage of cyclesin for time-aggregation compensation. The volume capacity becomes the limiting factor in total BB3 electricity sales profit from extreme prices in Poland. Figure 5.15 show that the BB3 electricity price results in Denmark show a higher number of high price hours and a significantly higher price magnitude. These price differences outweigh the limitations of the lower BB3 volume capacity of the HTTES storage in Denmark. This is the reason behind the increased profits in BB3 simulation of HTTES technology in Denmark in Figure 5.14 relative to BB2 total profits in Figure 5.12. Note that the price differences between BB2 and BB3 simulation are potentially due to missing capacity in BB3 simulation. Adding backup capacity such as gas turbines to BB3 simulation could reduce the magnitude of the price difference. This would result in the extremely high price hours being equal to the marginal costs of these backup units instead which does not necessarily make the BB3 prices more equal to BB2 prices. Price duration curves are shown in Appendix J.

In conclusion, storage capacity is optimized based on hourly aggregated BB2 prices and artificial volume capacity which creates an electricity sales profit mismatch relative to full-year BB3 simulation. The main reason behind the profit mismatch is the difference in extremely high prices between BB2 and BB3 simulation. A higher degree of price alignment between BB2 and BB3 simulations can reduce the HTTES profit difference. Currently, the number and magnitude of extremely high BB3 price hours in Western Denmark and Poland indicate non-utilized profit potential compared to the highest BB2 prices. This profit potential cannot be utilized due to volume limitations as shown in the example of Figure 5.10. This could be the case of other regions too.

The cyclesin parameter is necessary to have storage investments as a cyclesin value lower than 3 results in no endogenous storage investments due to time-aggregation limiting arbitrage trade opportunities. However, the application of cyclesin adds to the BB2 and BB3 electricity sales profit mismatch due to the removal of the cyclesin parameter in BB3 simulation. The endogenously installed storage capacity thereby becomes sub-optimal in full-year BB3 simulation. HTTES capacity in Poland is currently overrepresented and HTTES capacity in Denmark is underrepresented in BB3 simulation. Note that heat revenue between BB2 and BB3 is roughly the same. Revenue from heat sales constitutes 10-20 percent of the total revenue in Poland and Denmark in 2030. This implies lesser importance relative to electricity sales, yet still important to the feasibility of investments. Capture prices, charging costs, profits from electricity and heat of HTTES investments are further documented in Appendix L. In the end, it can be debated whether storage investments, which are mainly based on extreme price profits, are viable.

6 Sensitivity Analysis: The Impact of Cyclesin Value

This section will present the results of the sensitivity analysis which investigates the impact of varying the cyclesin parameter from the volume Equation 3.1. Different cyclesin values result in different levels of storage power and volume investment, shown in Figures 7.1, 7.2, 7.3 and 7.4.

The Figures show linearly declining lithium-ion investments as a function of decreasing cyclesin values. This is because lithium-ion batteries volume investment costs are significantly higher than HTTES. For this reason, the artificial volume capacity, gained from the application of cyclesin, is of higher value to lithium-ion batteries relative to HTTES technology. HTTES investments show a more parabolic relationship between investment and cyclesin value with a optimum at a cyclesin value of 4. When cyclesin equals 4, the value of lithium-ion batteries decreases enough to flip the scales in the favor of HTTES technology in Sweden and Poland, resulting in increased investments, shown in Figure 7.2 and 7.4. This corresponds with the previous observations in Figure 5.7 where HTTES and lithium-ion battery loading and unloading durations is shown to be relatively close.

In conclusion, it is difficult to properly represent storage technologies in BB2 capacity expansion simulations due to the time-aggregation. The choice of cyclesin will affect the attractiveness of storage technologies and the impact of volume investment costs on the objective function. Lowering the cyclesin value below 3 will result in no endogenous storage investments due to lack of compensation of the time-aggregation. This will, highly likely, not reflect the future development as utility scale storages are expected to increase [3]. Increasing the cyclesin value beyond 8, will increase the storage generation mismatch. Appendix M shows that average electricity price differences between BB2 and BB3 decrease as a function of decreasing cyclesin values potentially due to decreasing storage generation in Poland. The same tendency is seen in average capture price differences of PV and wind power between BB2 and BB3 in Appendix M.1.

7 Discussion

This section will discuss the main points of consideration regarding the model results.

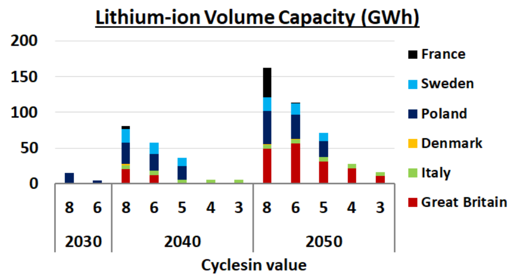

Figure 7.1: Levels of lithium-ion battery capacity investment per cyclesin value in different years. CNN scenario.

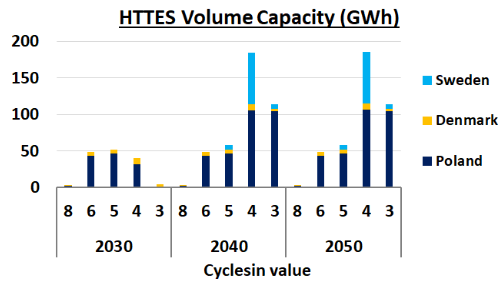

Figure 7.2: Levels of HTTES capacity investment per cyclesin value in different years. CNN scenario.

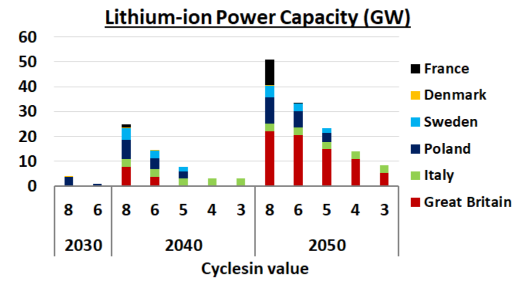

Figure 7.3: Levels of lithium-ion battery volume investment per cyclesin value in different years. CNN scenario.

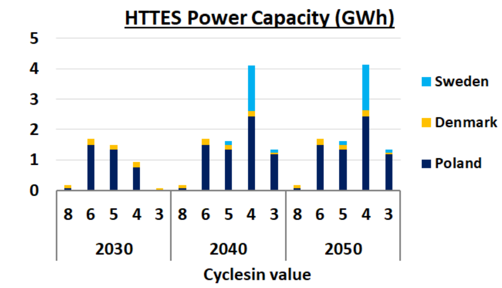

Figure 7.4: Levels of HTTES volume investment per cyclesin value in different years. CNN scenario.

7.1 NCES2020 Scenario Considerations

There is always uncertainty connected to predictions of future parameters such as demands, CO_2 prices, fuel prices and technological development. Many assumptions can change due to an uncountable number of reasons. The results of this thesis are built upon data that could potentially change in the coming years.

Input data, which is of higher concern, is the onshore and solar PV potentials throughout Europe. It is highly difficult to determine how much potential is economically and socially acceptable in perspective countries and regions.

General sector-coupling between the power, heating, transportation and industry could potentially have implications on electricity consumption.

7.2 Balmorel Storage Considerations

Balmorel operations are performed under the assumption of full foresight. This results in a unique situation in terms of storage dispatch as storage operations can be fully optimized and sized accordingly. In reality, complex algorithms for predicting future electricity prices would have an important role in the practical planning of storage operations. These will never have an accuracy matching the full foresight assumptions of Balmorel.

The representation of power storages in BB2 capacity expansion simulations should be improved. Different aggregation schemes could potentially provide different results and a more coherent generation between BB2 and BB3 simulations.

The applied means of storage revenue in Balmorel is through arbitrage trading. Additional types of revenue can be utilized such as frequency regulation or capacity markets. It is uncertain whether the HTTES technology will have the response time needed for frequency containment reserve which is the ability to deliver full capacity within 15 to 30 seconds in Denmark [19]. However, it is expected to have a response time below 30 seconds which is the required response time of automatic frequency regulation reserve in Denmark [19].

7.3 HTTES Costs

The HTTES costs are a source of uncertainty as no full physical storage has been built as of 2020. The investment costs and maintenance costs could potentially be different from those stated. Economics of scale could potentially also play a role in the development of storage costs. There is especially uncertainty regarding operating expenditures of the HTTES technology. Estimates on the operating expenditures of CAES installations vary from 1,400 € to 8,000 € in various sources [6][14][20][21]. There are no variable operating costs applied in this project but this could have been included.

7.4 Lithium-ion Battery Lifetime

There are different factors in optimizing the lifetime of a lithium-ion battery. Studies show that high operating temperatures lead to a faster decline in usable capacity [22]. If one were to maximize the cyclic lifetime, there might be additional costs related to battery installment such as cooling equipment. Additionally, studies have shown that calendar aging is increased by operating the battery at a high depth of discharge levels [22]. The lifetime of the battery could thereby become lower if lithium-ion batteries are applied the way it currently is represented in Balmorel. Applying the lifetime maximizing theory on storage operation would lead to higher volume investment costs. On that topic, note that the volume investment costs of the HTTES technology include the required cost of non-utilized volume capacity.

8 Conclusion

This section will present the conclusions of the model results.

8.1 Scenario Conclusions

The allowance of P2X electricity consumption redistribution at cost of 10 € per MWh fuel along with higher transmission expansion possibilities and Nordic onshore turbine potentials results in a socio-economic value of 5 billion € in the NPH scenario which is a 2 percent reduction of the objective function. The socio-economic value is mainly derived from shifting P2X electricity consumption to regions where it can be supplied with minimum costs. 186 and 95 TWh P2X electricity consumption is redistributed from South Germany and Italy to mainly Great Britain and the Nordic countries to minimize costs in the NPH scenario in 2050.

8.2 Storage Conclusions

The model results show that there is a socio-economic potential for power storage in many European countries which should be utilized. Storage capacity is installed despite flexible EV consumption being a major source of flexibility, generating 240 TWh as a virtual storage in the EU18 area in 2050, and a high level of allowed transmission capacity expansion. Underlying assumptions regarding P2X electricity consumption do have an indirect impact on storage investments in Sweden and Poland of especially lithium-ion battery capacity.

Results show that HTTES technology is cost-competitive to lithium-ion batteries at total cycle durations of above 16 hours in 2030 in Poland, Denmark and Sweden when performing arbitrage trading. 1.2 GW HTTES is installed in Poland with a 45 GWh volume in all scenarios. 150 MW HTTES is installed in Denmark with a 5 GWh volume in all scenarios. 150 MW HTTES is installed in Sweden with a 7 GWh volume in the CNN scenario. Cost reductions in lithium-ion batteries result in high battery investment in Great Britain and Italy in all scenarios in 2050.

High electricity price variation between time segments is a key prerequisite to endogenous storage investments as this increases arbitrage trading opportunities. The chronology of electricity price variation between time segments is another important prerequisite to the feasibility of endogenous storage investments.

Results show that differences in extremely high prices between BB2 and BB3 simulations result in the HTTES technology being underrepresented in Western Denmark and potentially other regions. This is based on a 12.5 million € electricity sales profit in BB3 simulation relative to 9 million € in BB2 simulation. The HTTES capacity installed in Poland, Denmark and Sweden is highly dependent on the utilization of extremely high prices which is difficult to carry out in practice. In Poland, BB3 results show that the installed HTTES capacity is currently overrepresented because the volume capacity cannot fully utilize extremely high price hours.

The parameter cyclesin is a necessary prerequisite to have endogenous storage investments due to BB2 temporal aggregation limiting arbitrage trade opportunities. However, the application of cyclesin adds to the mismatch between BB2 and BB3 electricity sales profit as cyclesin is not applied in BB3 simulation. The endogenously installed storage capacity thereby becomes sub-optimal in full-year BB3 simulation.

The socio-economic potential of HTTES technology show a modest level of investments relative to another study in which a different HTTES technology is applied. 14.3 GW, 7.5 GW and 1 GW of this HTTES is installed in Great Britain, Germany and Denmark respectively between years 2025 and 2035. [7].

8.3 Sensitivity Conclusions

The sensitivity analysis shows that the HTTES technology can compete with lithium-ion batteries to a higher degree in Sweden and Poland by decreasing the cyclesin value to 4. This is due to a significantly lower HTTES volume investment cost which reduces the impact of cyclesin values relative to batteries. Endogenous storage investments prove to be highly sensitive to the applied cyclesin value.

9 Further work

Many model sensitivities could use further investigation. The most important sensitivity is the impact of different temporal aggregation schemes on storage investments in BB2 simulations. The results could be compared to another temporal aggregation containing for example 4 full weeks, each representing a season. One should exercise extreme care in the selection of representative weeks as results are highly dependent on this selection. The impact of varying both HTTES investment costs and fixed costs could be analyzed. Lastly, the BB4 model mode could be applied for a less myopic investigation of endogenous storage investments compared to the BB2 model mode.

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A Appendix A: Balmorel Documentation

Balmorel is an open source model which promotes the transparency of the main code and discussion between researchers and other users. Balmorel is a partial equilibrium modelling of power and heating systems. The model can be used for technical or policy analysis on national and international levels. The geographical scope of the model is very flexible and can be adapted easily. Fundamentally, the model is a bottom-up model, meaning that each unit in a system is modelled individually to create the foundation of the overall energy system. The purpose of the Balmorel model is to minimize the total annualized cost of the entire energy system.

A.1 Modes within the Model

The Balmorel model is a deterministic model containing full foresight across chosen the modelling period. Variability in the model is implemented using profiles or capacity factors. This is both with respect to generation from for example wind and solar sources and demand side consumer patterns. Balmorel can run in two different optimizations, least-cost dispatch and least-cost investment, shown in Figure A.1. The two can applied at the same time or least-cost dispatch alone. The least-cost dispatch will optimize the unit dispatch so that the least-cost scenario is obtained. This simulates market conditions as merit order curves which is based on unit short term marginal costs are simulated. For power generation, the dispatch occurs for each individual region and time segment and for heat generation, this occurs for each demand area and time segment. The dispatch, of especially power generation, closely simulates real markets. The other mode, capacity expansion, is initially based on input data for exogenous units and build from there. Balmorel will determine whether it is lowering the objective function to invest in new units and decommission old units. If both modes are applied together, the capacity optimum is found and then the model iterates back to dispatch mode which then can result in a new capacity expansion iteration. The strength of the model is within this simultaneous co-minimization of new capacity costs and dispatch costs as well as simulating transmission and exchange between neighboring regions. The specific names of each model mode are the following.

- BB1 Economic dispatch for one year.
- BB2 Economic dispatch and capacity expansion for one year.
- BB3 Economic dispatch for each season iteratively.
- BB4 Economic dispatch and capacity expansion with a two or more year horizon.

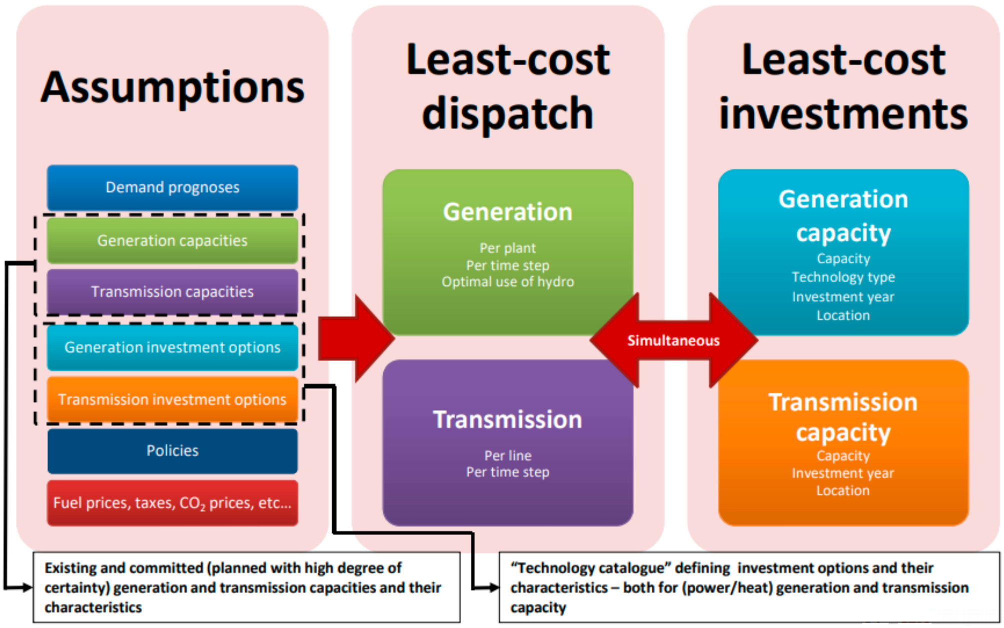

Figure A.1: Overview of Balmorel operation and input data[23].

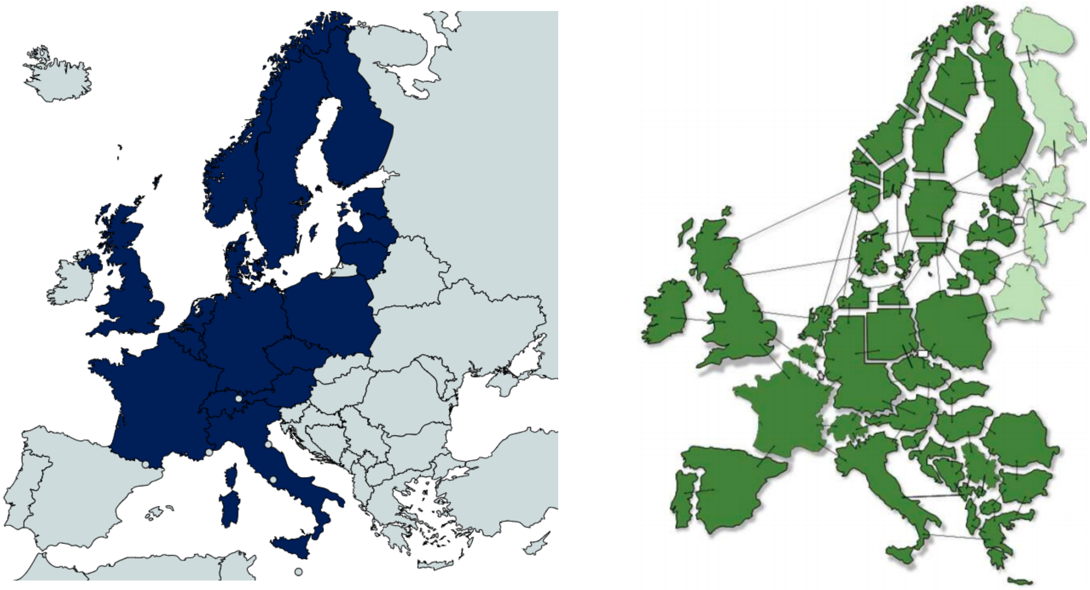

Figure A.2: Left Figure showing the simulated countries in Balmorel for this thesis. Right Figure showing existing or planned interconnections between countries in Balmorel[23].

Each mode can be applied for different types of analysis. One can link the model modes for deeper understanding of the results. The limiting factor in model runs are computational power as the model is dealing with large bottom-up power and heat systems. This calls for different sorts of assumptions and aggregations in order to lower the extensive computational demand of simulating different countries, for any number of time segments and simulation years. Temporal or spatial aggregations and assumptions can be adapted for this purpose. The input data and assumptions are demand forecasts, generation capacities, transmission capacities, generation&transmission investment options, current government policies, fuel prices, taxes on power or heat and CO_2-prices.

A.2 Spatial Representation

There are three distinct geographical layers of the Balmorel model. The country level, regional level and area level is shown with an abitrary example in Figure A.3. Power generation and demand is applied at the regional level, while heat is on a area level. In the base Ea model, Denmark is represented to a high degree of detail in terms of specific plants as well as district heating areas across the country. The remaining European countries are modelled in a more aggregated way with capacity of specific plants being grouped and the same is true for district heating areas. However, these countries will produce results of generation of power and heat which emulates reality. Analysis can be performed on any of the three geographical levels.

This dissertation will focus on the Nordic countries and the overall development in Europe as overall development is important to understand. The countries included in the model are shown in Figure A.2 to the left.

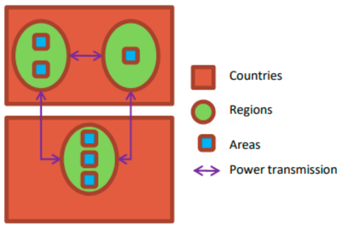

Figure A.3: Example of the three geographical layers in Balmorel[23].

A.3 Temporal Representation

There different temporal dimensions are applied in Balmorel, deployed in the following hierarchy.

- Years, the YYY set.
- Seasons(weeks), the SSS set.
- Time segments(hours), the TTT set.

The full Balmorel year is represented by 52 seasons, each containing 168 time segments, totalling 8734 time segment per year.

The model developer is free to chose any selection of years for simulation, given that necessary input data for that year is present. The optimization horizon changes between BB1, BB2 and BB3. The horizon is one year in BB1 and BB2 modes while it is per season in BB3 mode. BB4 mode operates with a yearly horizon but can iterate back and forth between each year depending on application. This is quite valuable because the model makes more long-term decisions.
The temporal aggregation of BB1 and BB3 is quite flexible but, in order to maintain validity, the aggregation should be representative of the seasons throughout the year. This thesis applies a temporal aggregation of 12 seasons, containing 11 time segment, for the BB2 mode. This is the standard of Ea Energy Analyses. The simulation years are 2020, 2030, 2040 and 2050. For BB3 mode, all 52 seasons with 168 time segment are simulated.

A.4 Demands in Balmorel

As Balmorel is exclusively simulating the power and heat sector, the demands in the model concerns these two commodities. Demands can be specified for any of the mentioned geographical levels. Electricity demands are typically specified on a region level while heating demands are specified on a area level. These are given exogenously and on annual basis with a hourly profile so that the model needs to meet a specific demand for each time segment simulated.

A.5 Power and Heat Generation

Intermittent and dispatchable power or heat generation are handled different in the model. Solar photovoltaic(PV) capacity is specified per area with each region having hourly irradiation flux profiles per area. Generation from wind power is calculated from regional wind speed profiles and specific power curves for different turbines, The regional dependency of these two types of generation allows for a more dynamic energy system as the generation varies from region to region, Dispatchable units are the controllable conventional plants which can be dispatched on command. These are given exogenously as input data or the model can choose to invest endogenously in capacity. Existing or planned transmission capacity between regions are exogenously implemented but the model can choose to invest in new capacity. Figure A.2 to the right shows the existing or planned transmission connections between regions in Europe.

A.6 Limitations in the Balmorel Model

There are mulitple limations to the Balmorel model which is listed below.

- Input data dependency.
- Full foresight assumption.
- One year optimizations in BB2.
- Temporal aggregation in BB2.
- Intraregional transmission.
- Perfect competition.

The Balmorel model is a partial-equilibrium model which relies 100 percent on the input data given. As the model simulates future years. Because of this, one must exercise caution when concluding on results from the model. There is a strong dependency on the input data and the given assumptions. The complexity of major societal changes are challenging to model which imposes a limited scope to present projections and assumptions concerning demands, prices and other types of future development. It is also very important to understand how the static input data concerning solar PV and wind turbines removes all uncertainty regarding the generation of these intermittent energy resources. In reality, the uncertainty of these types of generation units are a barrier for new investments as investing involves a great deal of risk.

The underlying assumption of Balmorel is full foresight to find the socio-economic optimum of future investments. This cannot be true for reality. Full foresight means that storages can be artificially efficient as market prices are known from the beginning. This leads to full optimization of arbitrage trade.
Investments from BB2 mode are only optimized on a one year basis which make potentially profitable long term investments less useful.

It requires a large amount of computational power or time to run the investment runs of BB2 mode for every time segment of every year.

The current solution to this problem is to make a temporal aggregation which limits the time segments in dispatch mode to fewer total time segments. This can potentially result in different outcomes relative to optimizing for all seasons and time segments of a year. The Balmorel model applies a simple transmission system which only contains limitations on interregional transmission. In reality, intraregional limitations should also be accounted for, especially in regions of increasing power demands.

Perfect competition is assumed in Balmorel which could prove to have very different outcomes relative to real market operation. Power markets are widely thought be well represented in Balmorel but real life bottlenecks can impose challenges which Balmorel easily could overwrite by investing in new transmission capacity due to the full foresight assumption. In practice, heat markets usually contain less perfect competition then what is reflected in Balmorel. Imbalances and imperfect conditions in these markets could lead to different outcomes.

B Appendix B: Data Calibration

This section will present the data processing of the scenario modelling. Two different data calibrations is performed.

- Capacity calibration in the model.
- Aggregation of areas in Denmark.

B.1 Calibration of Model Capacities

The base model needed some calibration in terms of capacities in the respective countries. These were particularly regarding the nuclear plant capacities in Sweden and Finland where policies continuously change. Sweden have recently decommissioned one of their Ringhals nuclear reactors, Ringhals 2, and are planning on closure of Ringhals 1 in December 2020 [24]. Finland are currently building two new nuclear reactors, 1,600 MW in Olkiluoto and 1,200 MW in Hanhikivi, scheduled to be ready for commissioning in 2022 and 2028[25].
The onshore wind capacities from 2016 to 2019 were outdated for Sweden, Norway and Finland in the base model. These were updated using real capacities and decommissioning profiles were created in order to phase out capacity after 25 years[26].

A calibration and validation of the year 2018 between the model results and real statistics is performed. Figure B.1 shows the difference between the capacities of each country of the model versus statistics from the EU Commission database [27]. In terms of capacity, the EU statistics indicate a higher magnitude of 1.6 GW combustible fuels in Denmark. While the model appears to have a 2.3 GW higher capacity in Finland relative to statistics. The difference in combustible fuels is less important in respect to the modelling, as these units are less utilized in the model, especially in the future where CO2 prices are projected to increase. These two differences in combustible fuels are therefore deemed negligible. In terms of PV, wind power, hydro and nuclear capacity, the differences are close to none which is important as these units will have the most influence on the dispatch.

The generation of the model versus the EU statistics is shown in Figure B.2. There are small differences between the two, as in Denmark, where the wind turbine generation is 2.4 TWh higher than in the statistics. Reversely, the wind turbine generation is 3.5 TWh higher in the statistics relative to the model. As the model applies fixed profiles and full load hours for wind turbine generation, these can either overrepresent or underrepresent actual values, as there can be a mismatch between actual geographical location of the turbines and the average values of a region in the model.
In Sweden, the statistics show a 12 TWh higher nuclear generation relative to the model. The difference is likely due to model derating of the nuclear capacity in GKDERATE.inc which contains profiles of planned maintenance shot-downs which affect the availability of the plant. It seems that the model derates the nuclear capacity in Sweden to a higher degree than stastics show. All in all, the margin of these differences are considered to be acceptable of the year 2018 as the magnitude of the statistics can be prone to small errors and the model is only an approximation of reality.

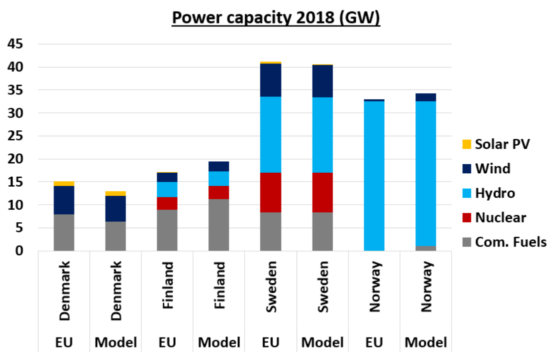

Figure B.1: Power capacity of the model relative to EU Commision statistics.

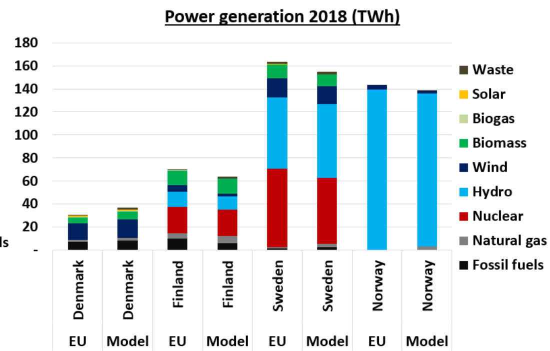

Figure B.2: Power generation of the model relative to EU Commision statistics.

B.2 Aggregation of Areas in Denmark

This section provides documentation of the aggregation of district heating areas in Denmark. The aggregation mainly focused on the medium and small areas of regions DK East and West to one group per region respectively. Additionally, many smaller areas in Copenhagen, Odense and TVIS are aggregated to three respective areas. The aggregation groups are shown in Table B.1.
As the medium and small areas had local power and heat capacity, these had to be aggregated as well. The local plants were aggregated by the following characteristics.

- Country
- Region
- Area
- Fuel
- Type(condensing, backpressure, extraction)
- Generation type, units which participates in unit commitment are different in GDTYPE.

The properties of each group such as CB-value, efficiency, costs and emissions is determined by a weighed average of the heating capacity of each plant. Groups containing extraction units with multiple fuel options were not aggregated in this manner.

B.3 Validation

This is a short validation of the resulting aggregated model with respect to the Ea base model. Power and heat generation are shown in Figure B.3 and Figure B.4. The Figures show that coal generation, shown in black, is decreased in the aggregated model with respect to the base model. This is due to new plans from Fjernvarme Fyn for the coal fired plant Fynsværket. The plant is now excepted to be converted to a natural gas backpressure unit by 2022 [28]. This results in a reduced power generation, 1,700 GWh, from coal in 2025 as well as reduced heat generation, 1.7 PJ in 2025, from coal.

The heat generation from storage units is larger in the base model for 2030 which indicates that storage capacity is less used in the aggregated model. Instead more direct heating is supplying the demand in the aggregated model, lowering the overall heat generation needed. Municipal waste heat generation increases roughly 1 PJ for both 2025 and 2030 while wood and wood pellet heat generation decreases by 2 PJ and 1 PJ respectively compared to base in 2030.

Power capacities are exactly equal in the two models. Heating capacities are very close to being equal but contain small differences to small variations in CB values. CB values of an aggregated group is based on a weighed average with respect to capacity which results in these small variations of total heating capacity. Additionally, there are close to no difference in power and heat prices in the aggregated areas.

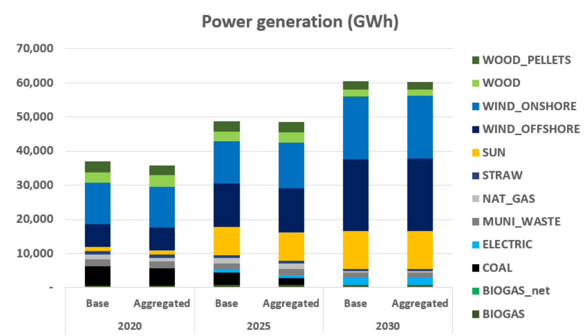

Figure B.3: Power generation in base model and aggregated model for 2020, 2025 and 2030 in GWh.

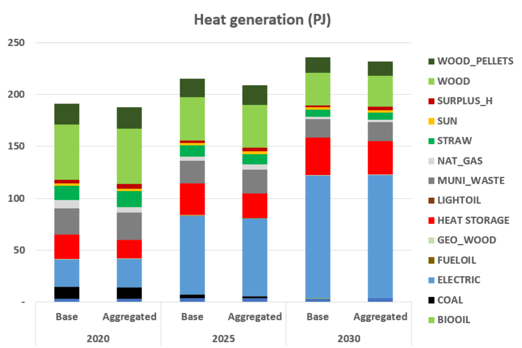

Figure B.4: Heat generation in base model and aggregated model for 2020, 2025 and 2030 in GWh.

New area	Former areas
DK_E_MA	Slagelse, Maribo, Kal, Ringsted, Roenne, Nyk, Naestved, Holte, NFHoersholm, NFBirkeroed, DTU, Farum, Helsingoer, Hilleroed, Hornbaek
DK_W_SA	DK_SA_W_BG DK_SA_W_EB DK_SA_W_NG_CHP DK_SA_W_NG_HO DK_SA_W_ST_HO DK_SA_W_WO_CHP DK_SA_W_WO_HO
DK_E_SA	Alleroed, FrkSund, Frksvaerk, Goerloese, Helsinge, MeloeseStL, Skaevinge, Slagslunde, Slangerup, Fredensborg, Jyllinge, Egedal, Gilleleje, Graested, Hundested, Jaegerspris. Skuldelev, Smoerum ,VejbyTisv DK_SA_E_BG DK_SA_E_NG_CHP DK_SA_E_NG_HO DK_SA_E_ST_CHP DK_SA_E_ST_HO DK_SA_E_WO_HO
DK_CA_Odense	Odense, Odense_Gart

New area	Former areas
DK_CA_TVIS	Kolding, Fredericia_S Fredericia_C, Fredericia_N Borkop, Vejle_S, Vejle_V Vejle_N, Vejle_E
DK_W_MA	Grenaa, Hjoerring,Holst, Horsens, Silk,Sndborg, Viborg, Hern,Randers, Aab, Frdhavn, Had, Hammel, Hobro, NrAlslev, Nyborg, Skive, Brndslv, Skagen, Svend, Thisted, Aars
DK_CA_Kbh	CAML, CHUS, CMID,CNOR, COST, CVAL,CTAR, VEKN, VEKV, HT,VKOG, Solroed, NORDHAVN,DHCV, DSMV, KONN, KONS,VESTERBRO, VFBallerup,VFNrdHvand, VFVaerloese,VFBagLyngby, JUNCKERS, VF

Table B.1: Overview of new aggregated areas and which old areas they include.

C Appendix C: Documentation of Changes in Balmorel Code with respect to HTTES Implementation

This section will describe how the code in Balmorel is modified in order to simulate the HTTES technology. The following measures is added:

- Volume equation: charge efficiency and a stationary storage loss.
- Heat generation on the charge cycle.
- Fixed operating and maintenance cost modification.

C.1 Volume Equation

As the HTTES technology is a power-to-power storage, it is included in the IGESTO_S(G) internal subset of generation technologies by adding a new GDTYPE, 51, to equation C.1. HTTES technologies are then defined as GDTYPE 51. As the HTTES storage technology is added to the IGESTO_S(G) internal set, there is no need for modification of the power balance equation in Balmorel.

The storage volume equation is modified to include two new features a charge efficiency and a stationary energy loss, shown in equation C.2. In order to give the best overview of the changes made, newly added changes are shown in bold. Previously, power storages only had a roundtrip efficiency which was used when discharging. A charge efficiency is added by multiplying the loading expression, VESTOLOAD, with GDATA(IGESTO, 'GDCOP') which contains a coefficient equivalent to the charge efficiency. The stationary storage loss is then subtracted by multiplying the loss constant, which is the percentage loss of the current content in MWh, by the current storage volume, multiplied by the length of the time segment, IHOURSINST, in hours. The storage loss is set to be 0.1% of the storage energy content per hour for HTTES technologies.

The direct Balmorel changes are shown in the following Equations.

Redefinition of IGESTO_S(G) generation technologies, in Balmorel.gms.

$$\begin{gathered} IGESTO\_S(G) = YES\$(GDATA(G,'GDTYPE')\ EQ\ 24 \\ \boldsymbol{OR(GDATA(G,'GDTYPE')\ EQ\ 51)}) \end{gathered} \tag{C.1}$$

Power storage volume equation, in Balmorel.gms. Note that division using cycle_sin is only applied in BB2 capacity expansion simulations.

$$\begin{aligned} &QESTOVOL(IA, IGESTO\_S, IS3, T) \quad \$(IAGK_Y(IA, IGESTO\_S) or IAGKN(IA, IGESTO\_S)).. \\ &VESTOVOL(IA, IGESTO\_S, IS3, T++1) = E = VESTOVOL(IA, IGESTO\_S, IS3, T) \\ &\boldsymbol{-(VESTOVOL(IA, IGESTO\_S, IS3, T) \cdot GDATA(IGESTO\_S,'GDSTOLOSS') \cdot IHOURSINST(IS3, T))} \\ &+IHOURSINST(IS3, T) \cdot (VESTOLOAD(IA, IGESTO\_S, IS3, T) \boldsymbol{\cdot GDATA(IGESTO,'GDCOP')} \\ &-(VGE\_T(IA, IGESTO\_S, IS3, T)/GDATA(IGESTO\_S,'GDFE'))\$IAGK_Y(IA, IGESTO\_S) \\ &-(VGEN\_T(IA, IGESTO\_S, IS3, T)/GDATA(IGESTO\_S,'GDFE'))\$IAGKN(IA, IGESTO\_S)) \\ &/CYCLESIN\_S(IS3) \end{aligned} \tag{C.2}$$

C.2 Heat Generation

The HTTES storage is different from other types of storage as it is a power-to-power storage which can utilize waste heat in the charge cycle, see Figure 3.1. The temperature of this waste heat is 90°C and should be cooled down to at least 50°C. This waste heat can be utilized through a heat exchanger connected to a separate district heating system.

A new set of storage type is defined as IGEHSTO to contain HTTES technologies and separate them from the IGESTO_S set. This is done for practical reasons. The set is defined for generation technologies (G). The set is defined to contain generators of GDTYPE 51, shown in equation C.3. The set is applied for further modelling of HTTES heat generation.

The HTTES technology heat generation needs to be constrained by a CB-value similar to that of conventional backpressure plants. A new equation is initialized which is called QGCBIGEHSTO, shown in equation C.4. The initialized equation is both defined for all areas, generation technologies, seasons and time segments.

The equation is implemented as shown in equation C.5. The Equation is defined for the set $IAGK_Y(IA, IGEHSTO)$, meaning all areas which contain positive exogenously or endogenously defined capacity for the technology IGEHSTO, for current simulation year, for the set IS3 which is present season simulated and time periods within the season in the simulation, T.

The defined equation is stating that the storage loading, as a function of all areas containing the technology IGEHSTO, present season in simulation and the associated time periods in that season, should be equal to the heat generation as a function of the same sets multiplied by the CB-value defined in GDATA of IGEHSTO technologies.

Furthermore, the heat generation of the HTTES technology needed to be added to the heat balance equation, shown in equation C.6. Here, heat generation of all generation technologies in the IGEHSTO internal set, in all areas, in the current simulated season, IS3, and in the current timestep T, is summed and added to the heat balance.

C.3 Fixed Operation and Maintenance Cost Modification

The operation and maintenance cost, O&M, of storages are usually given as a cost per MWh volume capacity. However, the HTTES technology needed to have the O&M cost defined per MW output power instead as the majority of fixed costs are related to turbine maintenance. This is modified by adding Equation C.7 to the objective function in Balmorel.gms.

Initialisation of new internal set, containing the HTTES technology alone, in Balmorel.gms.

$$IGEHSTO(G) = YES\$(GDATA(G,'GDTYPE')EQ51) \tag{C.3}$$

Initialisation of two new constraint equations, in Balmorel.gms.

$$QGCBIGEHSTO(AAA, G, S, T) \tag{C.4}$$

Implementation of new constraint equation for existing and new units(IAGK_Y and IAGKN), in Balmorel.gms.

$$\begin{aligned}
&QGCBIGEHSTO(IA, IGEHSTO, IS3, T)\$(IAGK_Y(IA, IGEHSTO) \textit{ or } IAGKN(IA, IGEHSTO))..\\
&VESTOLOAD(IA, IGEHSTO, IS3, T) = E = VGH_T(IA, IGEHSTO, IS3, T)\\
&\cdot GDATA(IGEHSTO, 'GDCB')
\end{aligned} \tag{C.5}$$

Addition to the heat balance equation, in Balmorel.gms.

$$
\begin{aligned}
& QHEQ(IA,IS3,T)\$(IDH\_SUMST(IA)..\\
& SUM(IGBPR\$IAGK\_Y(IA,IGBPR),VGH\_T(IA,IGBPR,IS3,T))\\
& +SUM(IGBPR\$IAGKN(IA,IGBPR),VGHN\_T(IA,IGBPR,IS3,T))\\
& +SUM(IGEXT\$IAGK\_Y(IA,IGEXT),VGH\_T(IA,IGEXT,IS3,T))\\
& +SUM(IGEXT\$IAGKN(IA,IGEXT),VGHN\_T(IA,IGEXT,IS3,T))\\
& +SUM(IGHH\$IAGK\_Y(IA,IGHH),VGH\_T(IA,IGHH,IS3,T))\\
& +SUM(IGHH\$IAGKN(IA,IGHH),VGHN\_T(IA,IGHH,IS3,T))\\
& +SUM(IGETOH\$IAGK\_Y(IA,IGETOH),VGH\_T(IA,IGETOH,IS3,T))\\
& +SUM(IGETOH\$IAGKN(IA,IGETOH),VGHN\_T(IA,IGETOH,IS3,T))\\
& -SUM(IGHTOE\$IAGK\_Y(IA,IGHTOE),VGE\_T(IA,IGHTOE,IS3,T)/GDATA(IGHTOE,'GDFE'))\\
& -SUM(IGHTOE\$IAGKN(IA,IGHTOE),VGEN\_T(IA,IGHTOE,IS3,T)/GDATA(IGHTOE,'GDFE'))\\
& -SUM(IGHSTOALL\$(IAGK\_Y(IA,IGHSTOALL)\ or\\
& IAGKN(IA,IGHSTOALL)),VHSTOLOAD(IA,IGHSTOALL,IS3,T))\\
& \boldsymbol{+SUM(IGEHSTO\$IAGKN(IA,IGEHSTO),VGH\_T(IA,IGEHSTO,IS3,T))}\\
& =E=(IDH\_T\_Y(IA,IS3,T)+SUM(DHF\_U,VDHF\_T(IA,IS3,T,DHF\_U))\\
& -SUM(DHF\_D,VDHF\_T(IA,IS3,T,DHF\_D)))/(1-DISLOSS\_H(IA))\\
& -VQHEQ(IA,IS3,T,'IMINUS')+VQHEQ(IA,IS3,T,'IPLUS')
\end{aligned}
\tag{C.6}
$$

Implementation of changing the fixed costs, GOMFCOST, to the power capacity of the HTTES technology in Balmorel.gms. This cost is usually associated to the volume component of storage.

$$
\begin{aligned}
& +IOF1000\cdot(SUM(IAGK_Y(IA,G)\$(GDATA(G,'GDINVCOST0UNLO')\\
& and\ IGEHSTO(G)),IGKVSTOACC(IA,G,'Unloading')*GOMFCOST(IA,G))\\
& +SUM(IAGKN(IA,G)\$(GDATA(G,'GDINVCOST0UNLO'))\\
& and\ IGEHSTO(G)),VGKNSTO(IA,G,'Unloading')\cdot GOMFCOST(IA,G))))
\end{aligned}
\tag{C.7}
$$

D Appendix D: HTTES Input Changes to Balmorel

The following .inc files is changed to accommodate the HTTES implementation.

- Balmorel Set G.inc
- tech.inc
- GFKX_DK_other.inc
- investments.inc
- unit results.inc
- bb123.sim

In Balmorel Set G.inc, the new technologies HTTES were added as a generation technology set, shown in equation D.1. These technologies include both HTTES units which can produce heat from waste heat, denoted as _BP and condensing units that do not have heat generation, denoted as _CON.

The investment.inc file specifies series of macro sets which contain technologies that are available for future investment. Depending on the area, different technologies are available for investment. A new macro set is made for the HTTES technology called HTTES_INV(GGG) which contains the HTTES technologies of different years from 2020 to 2050, shown in equation D.2. There is a need for differentiation of the HTTES technology as parameters are expected to slightly change over the years. The marcro set HTTES_INV(GGG) is added to area types 1 and 2 which are central areas of different types. These areas is chosen because the HTTES storage is thought to require economics of scale in order to be cost-competitive.

The tech.inc files specifies the technology data of future years of the technology which have a slightly different parameters from decade to decade due to assumed technological development. Data from Table 3.1 is applied.

Implementation in Balmorel Set G.inc

$$\begin{aligned}
&HTTES-20_29_BP\\
&HTTES-30_39_BP\\
&HTTES-40_49_BP\\
&HTTES-50_BP\\
&HTTES-20_29_CON\\
&HTTES-30_39_CON\\
&HTTES-40_49_CON\\
&HTTES-50_CON
\end{aligned} \tag{D.1}$$

Implementation in investments.inc

$$\begin{aligned}
&SET\ HTTES_INV_INV(GGG)\\
&HTTES-20_29_BP\\
&HTTES-30_39_BP\\
&HTTES-40_49_BP\\
&HTTES-50_BP\\
&HTTES-20_29_CON\\
&HTTES-30_39_CON\\
&HTTES-40_49_CON\\
&HTTES-50_CON
\end{aligned} \tag{D.2}$$

Addition of HTTES heat generation to unit results.inc.

$$\begin{aligned}
&UNITRESULTS_T(Y, CRAGF(C, IR, IA, IGEHSTO, FFF), S, T,'Heat\ generation(TJ)') =\\
&IOF3P6 \cdot\ IHOURSINST(S,T) \cdot\ (VGH_T.L(IA, IGEHSTO, S, T)\\
&+VGHN_T.L(IA, IGEHSTO, S, T))/IOF1000
\end{aligned} \tag{D.3}$$

Addition of HTTES marginal heat value to unit results.inc.

$$UNITRESULTS\_T(Y, CRAGF(C, IR, IA, IGEHSTO, FFF), S, T, 'Marginal\ Heat\ Value(TJ)') = IOF3P6 \cdot IHOURSINST(S, T) \cdot (VGH\_T.L(IA, IGEHSTO, S, T) + VGHN\_T.L(IA, IGEHSTO, S, T))/IOF1000 \tag{D.4}$$

E Appendix E: HTTES Technology Documentation

HTTES technology concepts has been under development for the last decade. As of 2020, a cooperation have been made between a variety of different companies and institutions in order to further accelerate the research concerning the storage. Among these are SEAS-NVE, DTU Energy, Aarhus University, Rockwool, Danish Energy and Energinet.dk. A pilot project has been created at DTU where the storage unit was build for thermodynamic research [11]. Further realizations of a full pilot project are in planning. The technology development is supported by the Energiteknologisk Udviklings- og Demonstrationsprogram (EUDP).

The DTU storage unit is shown in Figure E.1. The unit is 2 meters in diameter, contained 5,394 kg of Swedish diabase rock each in the size of 8-11 mm[11]. The storage was build into the earth with 400 mm isolation and 200 mm of concrete. The total storage capacity of the storage is 1 MWh useful thermal energy, that is 1 MWh ready for discharge[11]. Kurt Engelbrecht, the chief engineer of the pilot project, from DTU estimates that the storage can be scaled to be 30 meters in diameter with a capacity of 3 GWh. The HTTES technology, applied in this thesis, is build on a Engineering Equation Solver(EES) model given by Stiesdal A/S who is developing the specific concept. The EES model, in question, is shown in Figure E.2. Table E.1 shows the different parameters such as temperature, pressure and volume of the air in different numbered parts of the component diagram.

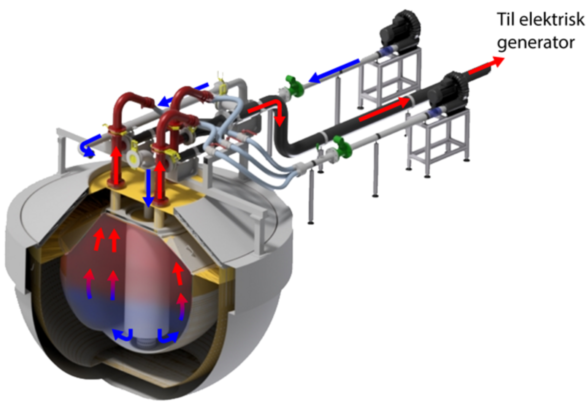

Figure E.1: Image showing the storage unit at DTU[11].

E.1 HTTES EES Model and Specific Financial Data [12]

Position	Temperature[C]	Pressure[kPa]	Volume[m3/h]
1	450	638.2	26053
2	75.3	635.3	12583
3	35	626.3	11271
4	-19.5	282.9	20520
5	292.2	280	46362
11	80.3	736.4	11014
12	445	733.5	22521
13	297.2	282.9	46294
14	-14.5	280	21147
20	340.7	367.4	
22	40.2	508.2	
23	384.5	508.2	

Table E.1: Parameters for the numbered areas in schematic [12]

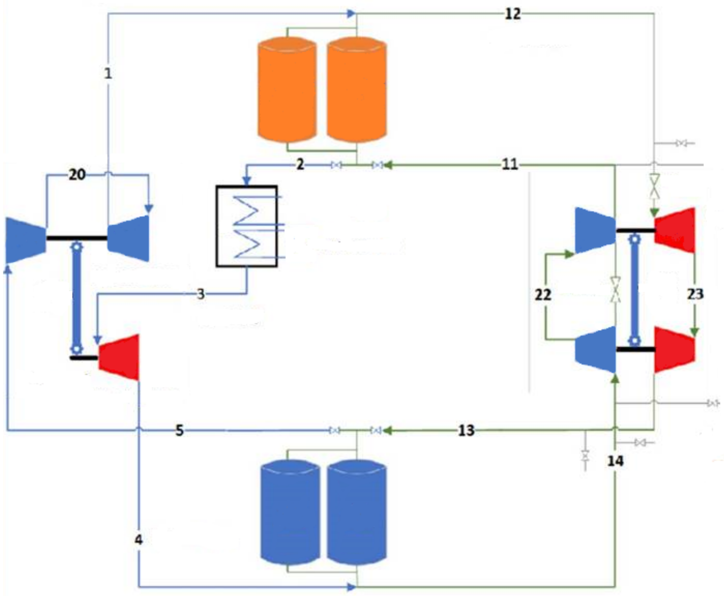

Figure E.2: Schematic of the system components, blue marking the charge cycle and green marking the discharge cycle[12]

F Appendix F: Input overview of NCES2020 scenarios

This section will provide an brief overview of input data and sources applied in the NCES2020 scenarios.

- Technical potentials
  - Onshore wind power potential
    - ETC -European Environment Agency for maximum technical potential [29]
    - CNN scenario constains further Nordic onshore turbine potential limitations from NMBU, VTT and Energiforsk. These are arbitrary numbers which serves the purpose of mimicking local resistance to investments of onshore turbines, shown in Figure F.1
  - Offshore wind power potential
    - 4C Offshore reports and ENSPRESO [30] [31].
  - Biomass potential
    - EU Commission, IPCC and the Danish Energy Agency[15][32][33].
  - Solar PV potential
    - Solar Potential [34].

- CO2 and fuel prices
  - World Energy Outlook 2020, Sustainable development scenario[16].
  - Local biomass prices are applied in the Nordics from the Danish Energy Agencies report on "samfundsøkonomiske beregninger for biomasse."[32].
- Technology data
  - Danish Energy Agency[13][6].
- Existing unit capacities
  - Conventional units
    - ENTSOE Transparency Platform.
  - Onshore and offshore wind power capacites
    - Thewindpowernet[26]
  - Solar PV
    - IEA PVPS Annual Report 2019, [35]
- Planned or existing transmission capacity between regions.
  - ENTSOE and local TSO's.
- Electricity consumption
  - European-Commission, COMBO scenario [15].

Onshore Potentials (GW)				
Scenario	**CNN**	**CNN**	**NPH**	**NPH**
Country	**2030**	**2050**	**2030**	**2050**
Denmark	5.5	5.5	5.5	5.5
Norway	7.5	12	11	27
Sweden	20	30	32	77
Finland	13	25	25	72

Table F.1: Onshore potentials applied in different scenarios.

G Appendix G: Biomass Assumptions

This section will document the assumptions behind the model area wide biomass constraint of 2,537 PJ. The EU COMBO scenario suggest a bioenergy feedstock of roughly ≈2,500 PJ forest stemwood, ≈2,500 PJ forest residues and ≈700 PJ residue from the pulp and paper industry in 2050 [36]. Assuming half of these feedstocks are available to the power industry, a total of roughly 2850 PJ wood is available to all of the EU. However, not all EU countries are modelled in Balmorel. The estimate becomes 2,537 PJ when corrected by population. Figure G.1 shows the biomass consumption of the model area.

In comparison, this constraint roughly corresponds to IPCC and Danish Energy Agency assumptions about maximum global consumption[33][32]. The IPCC states that a global consumption of 100 EJ per year in 2050 will be a sustainable level but between 100-300 EJ is available [33]. 100 EJ is roughly equivalent to 10 GJ per person per year in 2050[32]. It is assumed that the EU model area usage of biomass will be above the global average. Hence, 12.5 GJ per person per year is applied in the model area. It is also assumed that 50% of this biomass fuel is available to the power and heat sector which is equivalent to the EU COMBO scenario assumptions [15]. The model area contain 406 million people which makes the total available consumption around 2,540 PJ.

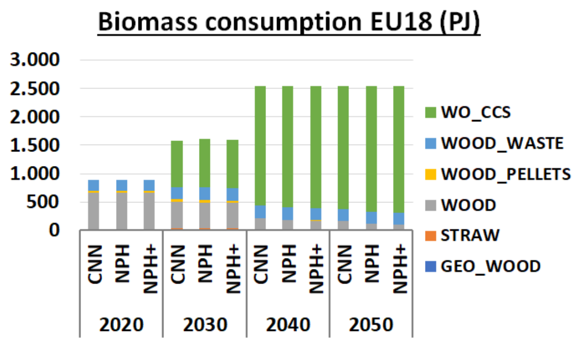

Figure G.1: Biomass consumption of the model area, EU18.

The Figure shows that mainly wood fuel is consumed in the model area with very little straw consumption. The Figure also shows that the maximum consumption is reached in 2040.

H Appendix H: Flexible EV Consumption

The model contain a flexible consumption in the form of EV-smart-charging which acts as a virtual storage. The total EV power and volume capacity is calculated based on the EU COMBO EV consumption. A technology named EV smart charging is defined based on the specifications of a Nissan Leaf EV. The power capacity of this technology is defined as 7.5 kW per car and a volume of 30 kWh. However, the amount of EV charge, discharge and volume capacity is limited to a fraction of the total EV fleet.

There are two kinds of percentage ratios to modulate the amount of flexible consumption that the storage can deliver, which is the upper and lower limits of capacity usage. The upper bound represents how much the EV demand can be increased, virtual storage loaded, as a share of the total available parked cars, shown in Figure H.1. Percentage ratios of the upper bound is also applied for the share of the total storage volume which can be used at any time, shown in Figure H.2. The Figure also shows that there is an hourly profile derating the storage volume so one hour in the day, before morning rush, the volume of the virtual battery is empty, meaning consumption cannot be increased or decreased in this hour.

The lower limit represents how much the EV demand can be decreased, virtual storage unloaded, as a share of natural demand. In other words, how many cars which are plugged-in are willing to unplug.

The upper limit starts at 7% of all EV capacity in 2020 and increases linearly to 18% in 2050. The lower limit starts at 20% of EV capacity in 2020 and increases linearly to 80% in 2050.

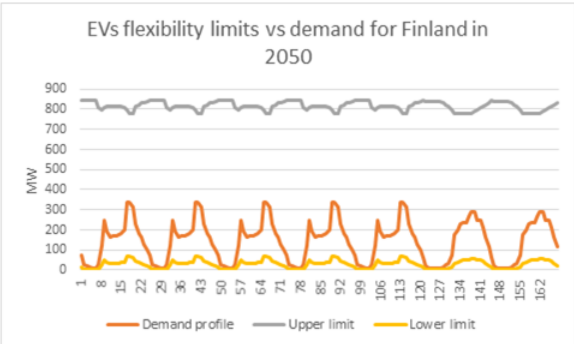

Figure H.1: Example of EV demand profiles, upper and lower limits

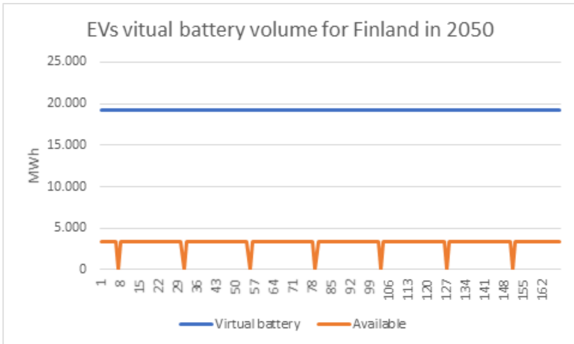

Figure H.2: Example of virtual battery volume and availability in different hours assuming a 4 hour storage volume.

I Appendix I: NCES Scenario Findings, Transmission Results

I.1 Model Area Electricity Flows

Figure I.1 shows the electricity flows between regions in the CNN scenario in 2050. Generally speaking, there is a flow of electricity from peripheral countries towards South Germany called DE_CS. Starting from the left in Figure I.1, it shows large flows of 28 TWh, 53 TWh and 34 TWh from Great Britain to France, Belgium and the Netherlands respectively. France is also a major exporter of electricity with 43 Twh to Belgium, 38 TWh to Luxemburg, 78 TWh to South Germany, 65 TWh to Switzerland and 67 TWh to Italy. The Netherlands and Belgium function partly as intermediary regions were large flows are imported and exported to South Germany. However, as Figure 4.8 shows, the Netherlands does host a relatively large offshore capacity in the North sea that add to the flow.

The Northwest and Northeast German regions have a quite large capacities of solar PV, onshore and offshore turbines installed compared to local demand.This results in very significant electricity export magnitudes of 175 TWh from the Northwest and 119 TWh from the Northeast to the mainland German regions. Denmark serves as a net importer of electricity from Norway and Sweden in order to meet its demand. Sweden hosts some large magnitudes of electricity flows through its regions with 24 TWh coming from Finland and 46 TWh from the North SE_N2 region, flowing towards Denmark and Poland. Norway is mainly exporting to Denmark and the Netherlands. Poland imports power from the Baltics and Sweden and export a greater magnitude of 50 TWh to Middle-east Germany called DE_ME.

As Figure 4.9 shows, a significant magnitude of roughly 200 TWh P2X power demand has been shifted away from the South German region to the previously stated countries in the NPH scenario 2050. Figure I.2 shows the electricity flows of the NPH scenario in 2050. The flows needed to supply the South German consumption is reduced heavily.

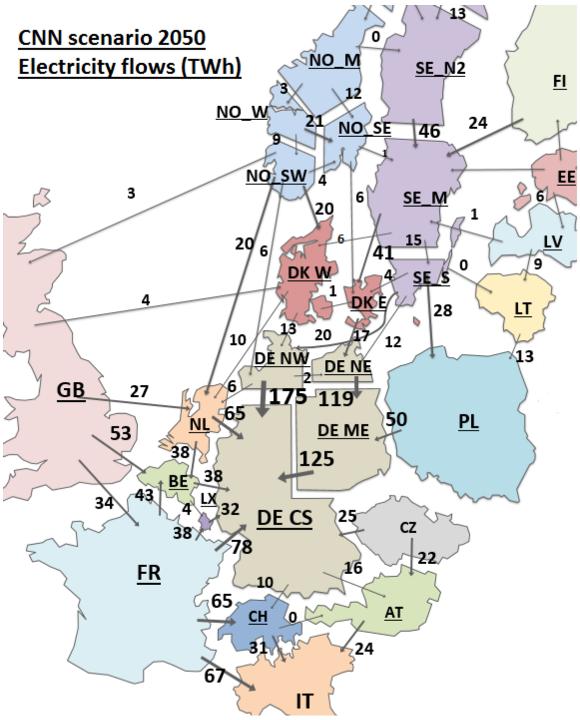

Figure I.1: Net electricity flows, in TWh, in the CNN 2050 scenario.

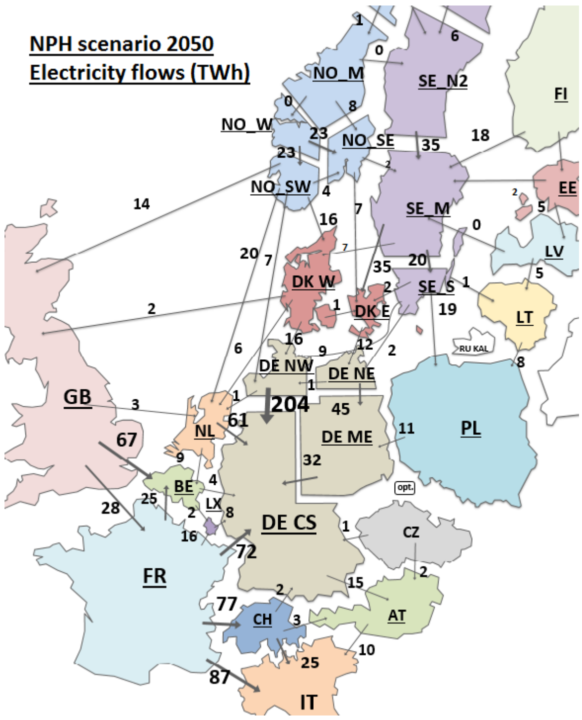

Figure I.2: Net electricity flows, in TWh, in the NPH 2050 scenario.

I.2 Transmission Flows regarding Poland and South Sweden

Figure I.3 and I.4 show the net electricity flows from and to Poland and South Sweden. Both Figures show a relatively large electricity flow to German regions DE_ME, DE_NW and DE_NW in the CNN scenario which reflect the map shown in Figure I.1. Figures I.5 and I.6 show the additional power capacity required to maintain this large electricity flow to German regions in the CNN scenario. This additional capacity is consists mainly of solar PV, offshore wind turbines and storage. The demand of export to German regions is the reason behind additional CNN scenario storage capacity in Poland and Sweden in Figure 5.1 and 5.3

The NPH/NPH+ scenario show that offshore turbine capacity in South Sweden is heavily reduced in 2040 and 2050. The decreased capacity results in a 14 TWh reduction in electricity export to Germany and Poland in 2050. The reduction in export is caused by the shifted P2X electricity consumption which reduces the German need for electricity import. This reason also applies to Poland as export to German regions is significantly reduced by 47 TWh between CNN and NPH scenario in 2050 in Figure I.3. Figure I.5 shot that the PV panel capacity in Poland is reduced in the NPH scenario in 2040 and 2050.

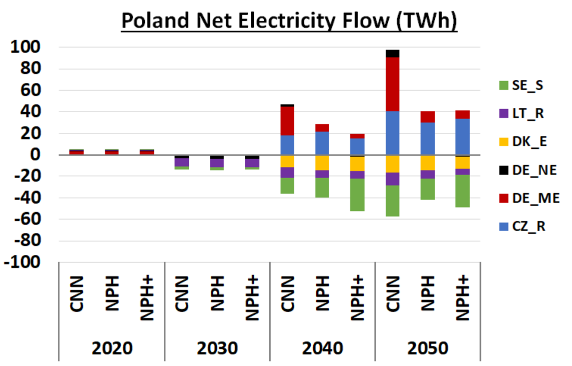

Figure I.3: Net electricity flows, in TWh, in Poland.

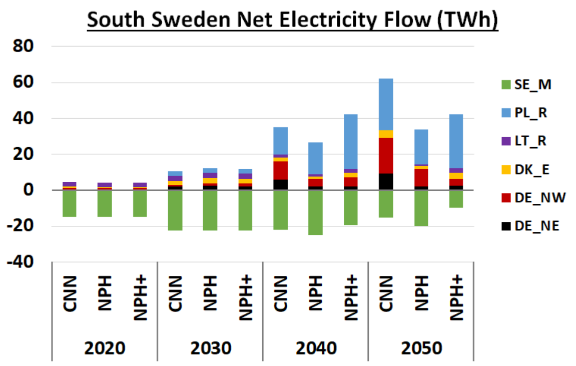

Figure I.4: Net electricity flows, in TWh, in the South Sweden region.

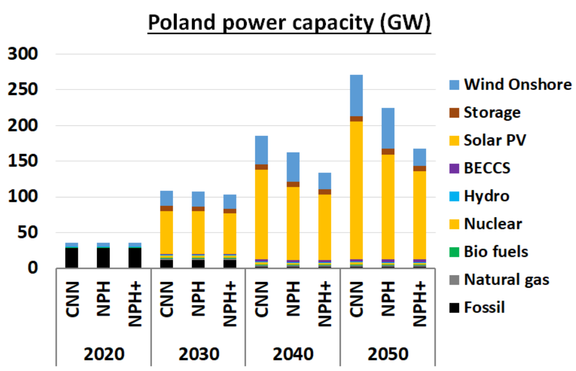

Figure I.5: Power capacity development in Poland.

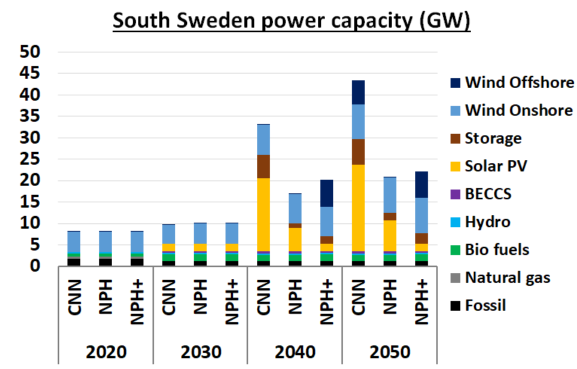

Figure I.6: Power capacity development in the South Sweden region.

J Appendix J: Price Duration Curves

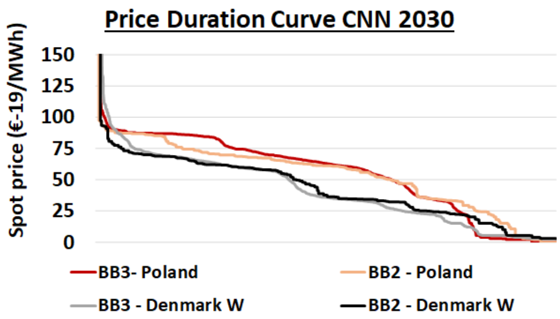

Figure J.1: Price duration curve of Western Denmark and Poland of BB2 and BB3 simulations in 2030.

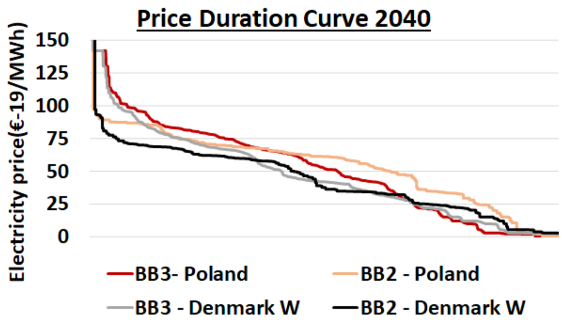

Figure J.2: Price duration curve of Western Denmark and Poland of BB2 and BB3 simulations in 2040.

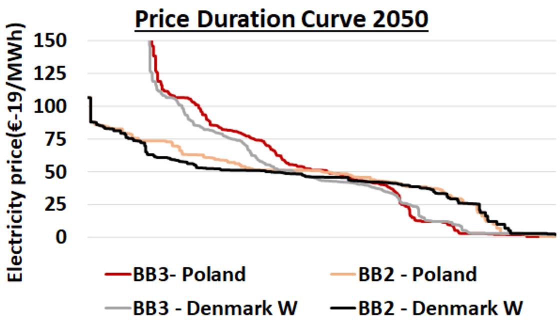

Figure J.3: Price duration curve of Western Denmark and Poland of BB2 and BB3 simulations in 2050.

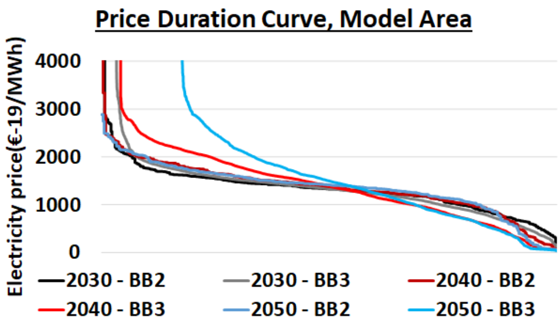

Figure J.4: Price duration curve of the whole model area in all years of BB2 and BB3 simulations.

K Appendix K: HTTES Dispatch in Poland

In Figure K.1, dispatch profiles of Poland show that the HTTES storage is a good fit for onshore wind power as this resource provides large magnitudes of power for longer time intervals. Generally, this results in longer durations of lower prices with respect to shorter PV generation durations. This overlaps with longer loading durations needed to fully load a HTTES storage. Analysis by Dansk Energi shows similar results[37]. PV generation daily generation is also resulting in HTTES cycles. However, Figure K.1 shows that many of the short intervals of PV generation are not enough to fully loading the storage. Additionally, Figure K.1 shows that cycles are most frequent in periods of high onshore wind power generation. The same tendencies are seen in Swedish dispatch results. Similarly to Poland, HTTES investments in Denmark do not vary between scenarios but this is due to no significant system change between scenarios. Generally, the results show a very low variation and magnitude of heat prices compared to power prices. The operation of an HTTES investment is therefore mainly focused on arbitrage trading on the power market.

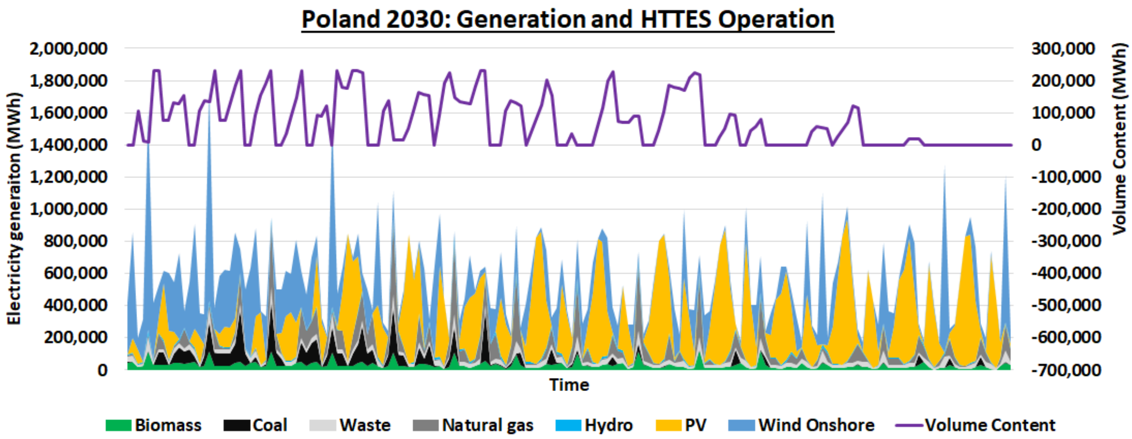

Figure K.1: Poland 2030 generation by fuel in weeks 1 to 14 from BB2 results. All generation types are shown on the primary axis and storage volume is shown on the secondary axis.

L Appendix L: HTTES Capture Prices and Annual Revenues

L.1 Capture prices

Figure L.1 show that investments in Western Denmark have a higher average selling price of 87 € per MWh electricity in the BB3 simulation compared to 80 € per MWh in BB2 which indicates that the storage investments in the region are underrepresented.

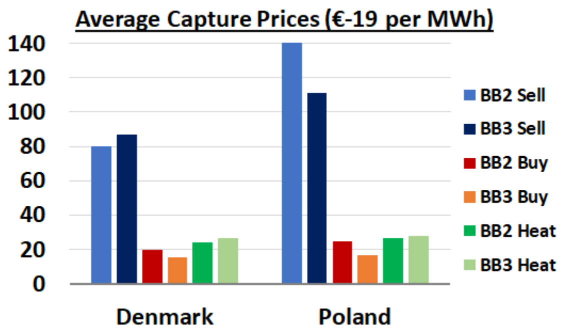

Figure L.1: Average capture prices of HTTES investments in 2030 across scenarios.

Figure L.1 shows that the average selling price per MWh in Poland is reduced from 140 € per MWh in BB2 simulation to 110 € per MWh in BB2 results. Note that the average selling price of electricity is around twice as high in Poland compared to Western Denmark in BB2 simulation which explains the significantly higher power and volume investments of Figure 5.3 and 5.4. The average price of heat generation is very similar between countries Denmark and Poland and between BB2 and BB3 simulation. The average heat price vary with a value of 24 to 28 € per MWh. The average buying price is 23 percent reduced in Denmark in BB3 simulation relative to BB2. The average buying price is 33 percent reduced in Poland in BB3 simulation relative to BB2.

L.2 HTTES Revenues and Charging Cost

Figure L.2 shows a break-down of annual revenues and charging costs of HTTES investments in Poland and Western Denmark in BB2 and BB3 simulations in 2030. Note that the cash flow is excluding annualized investment cost and fixed cost.

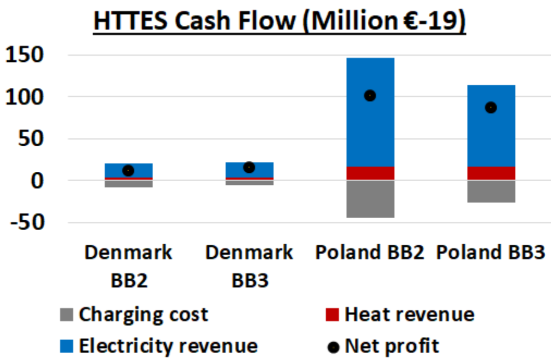

Figure L.2: Break-down of revenues and charging costs of Denmark and Poland in 2030 of HTTES investments.

The Figure shows that the total annual electricity revenues increase in Denmark in BB3 relative to BB2 by 4 million € due to higher revenues from electricity sales and lower charging costs. Reversely, BB3 annual revenues in Poland shows a reduced revenue from electricity sales but a significantly lower annual charging cost as well. These annual revenues and charging costs in Denmark and Poland are linked to average buying and selling prices from Figure L.1. Lower average sell and buy prices results in lower revenues and lower charging costs respectively. All in all the results show a total decreased revenue of 14 million € in a BB3 in Poland compared to BB2. Additionally, there is a small electricity generation reduction of 4 and 1 percent in Poland and Denmark in BB3 results relative to BB2.

M Appendix M: Electricity Prices and Capture Prices as a function of Cyclesin Value

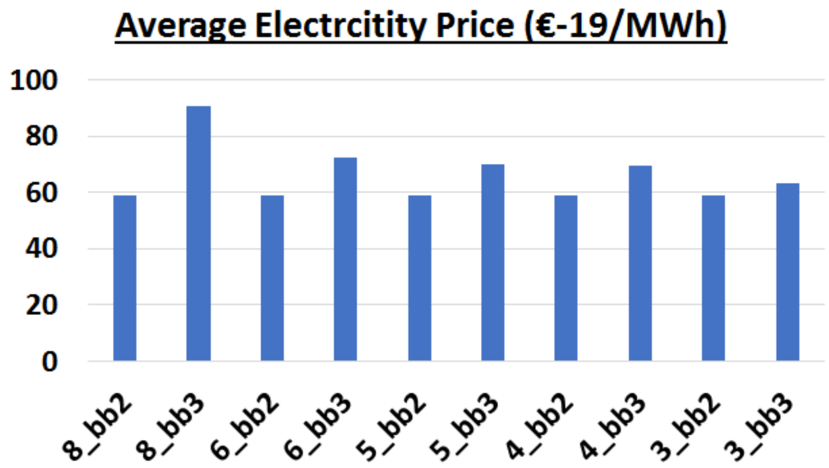

Figure M.1: Average electricity prices at different cyclesin values(8 to 3) in BB2 and BB3 simulation in Poland in 2030.

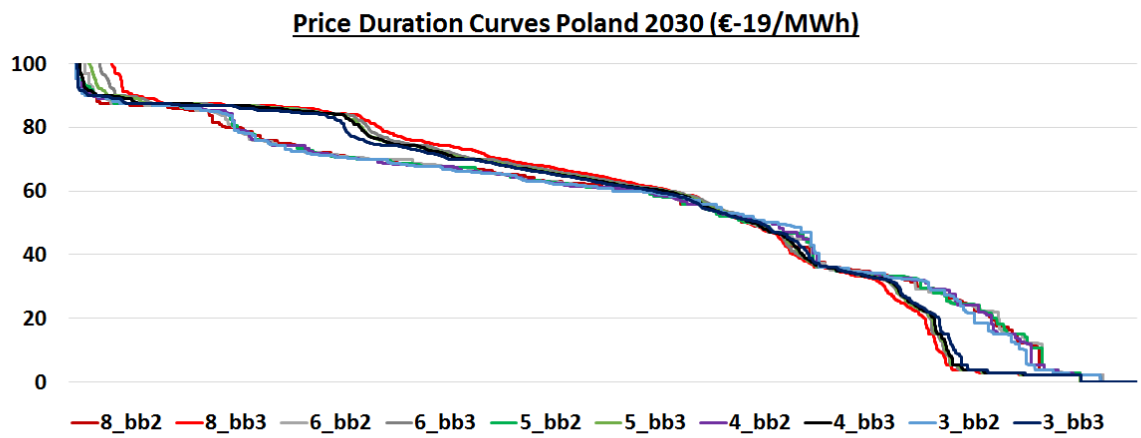

Figure M.2: Prices duration curves at different cyclesin values (8 to 3) between BB2 and BB3 simulation in Poland in 2030.

M.1 Appendix N: Captures Prices of PV and Onshore wind Power as a function of Cyclesin

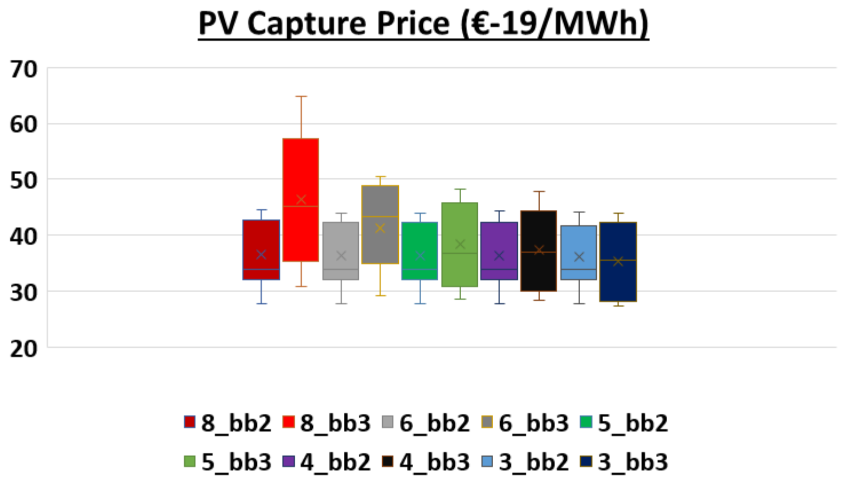

Figure M.3: Distribution of PV capture prices in all countries at different cyclesin values (8 to 3) between BB2 and BB3 simulation in 2030.

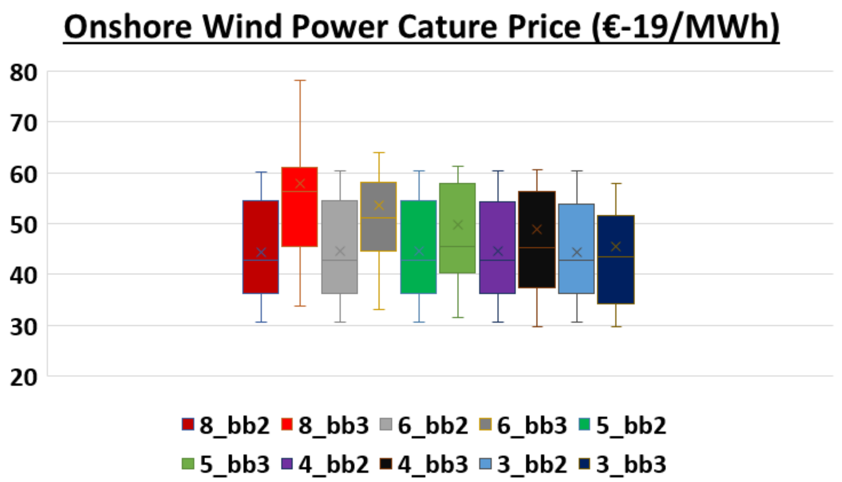

Figure M.4: Distribution of onshore wind power capture prices in all countries at different cyclesin values (8 to 3) between BB2 and BB3 simulation in 2030.

N Appendix N: Regional Nomenclature for Balmorel

DE_CS = South Germany
DE_ME = East Germany
DE_NW = Northwest Germany
DE_NE = Northeast Germany
DK_W = Western Denmark
DK_W = Eastern Denmark
FI = Finland
FR = France
GB = Great Britain
IT = Italy
NL = Netherlands
NO = Norway
PL = Poland
SE = Sweden