Bio-FlexGen

Cost-benefit analysis for system integration of the BTC

D4.2

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Summary

Summary of Deliverable

This deliverable assesses the integration and profitability of BTC technology within Sweden and Spain's electricity and heat systems using the openTEPES modelling tool. The base cases consider referred parameters from the National Energy and Climate Plan from Spain and Sweden, but key sensitivities are also considered.

According to the Spanish Energy and Climate Plan, the Spanish electricity system is expected to achieve 81% renewable electricity generation by 2030 and 100% by 2050 [1]. For 2030, BTC technology enables renewable generation to surpass the 81% threshold. Results for the Spanish 2030 scenarios indicate that, under the given modeling assumptions, BTC is a competitive technology that can participate in both the electricity and heat sectors, even when compared with conventional biomass CHP technology. Incorporating BTC leads to lower electricity marginal costs and higher shares of renewable generation in both sectors. Additionally, the results show a preference for cogeneration and electric heat technologies, such as electric boilers and heat pumps, over carbon-emitting boilers, despite the latter's lower investment costs. However, while hydrogen boilers can help decarbonize heat production using renewable fuel, their high CAPEX values render them non-competitive. Three different sensitivities were modeled: increases in biomass prices, CO_2 emission prices, and the efficiency of traditional CHP. BTC investment remained stable in all cases, with only marginal changes in BTC generation.

As for 2050 for the Spanish case, initial assumptions reveal that BTC technology is not as competitive, with no investments in the main scenarios, primarily due to its high CAPEX compared to conventional biomass CHP technology. However, the model indicates investments in BTC with a small 10% reduction in their investment cost. Electrification of heat production exceeds 80%, with biomass boilers and CHPs complementing the mix. Additionally, higher biomass prices make CHP and biomass

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boiler generation less attractive while increasing the competitiveness of BTC due to its higher efficiency.

Swedish TSO has developed different scenarios/economic pathways to analyse long term market behaviour towards green transition. Swedish cases for the reference years of 2035 and 2045 are created adopting a long-term market scenario and a set of modelling assumptions. Several simulations for 2035 and 2045 Swedish energy system were conducted. It is important to notice that conclusions are extracted based on the results obtained from simulations under certain modelling assumptions. To generalise the results more simulations and deeper sensitivity analyses need to be carried out

The results obtained from all cases simulated for the reference year of 2035, Sweden show that to satisfy the system electric demand the model prioritises BTC investment over nuclear technology. However, for a situation where the need for investment in heat generating technologies is higher to meet the system heat demand than that of for electricity, the model prefers to invest in CHP_biomass rather than in BTC technology. This behaviour is consistent even if we decrease BTC CAPEX. A 25% decrease in BTC CAPEX results in 2.44 MEUR/MW, while CHP_biomass has CAPEX of 2.94 MEUR/MW. In the system where there is a bigger need to invest in heat generating technology to meet the heat demand than that of electricity, the model prefers to invest in CHP_biomass technology as every MW of electric power installed for CHP the system gets 3 MW of heat power installed (with a CAPEX of 2.94 MEUR/MWe), while for BTC, the system only gets 0.63 MW of heat power installed (with a CAPEX of 2.4 MEUR/MWe).

As for the reference year of 2045, integrating BTC technology in the generation mix energy system we experience the opposite effect that we observed while integrating BTC technology in the 2035 Swedish energy system. In 2045 reference case, where the need for investment in electricity generating technologies is higher to meet the system electric demand than that of for heat, the model always finds BTC technology more competitive to invest in than other technologies. All simulations for the 2045 Swedish energy system under the modelling assumptions highlighted that BTC is a competitive technology and can participate in both electricity and heat markets to contribute to satisfy both system electricity and heat demand.

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Table of contents

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This project has received funding from the European Union's Horizon 2020 research and innovation programme under grand agreement N° 101037085.

Table of tables

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grand agreement N° 101037085.

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Table of figures

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Abbreviations

BTC	Biomass-fired Top Cycle
CAPEX	Capital expenditures
CHP	Combined Heat and Power
COP	Coefficient of Performance
DA	Day-Ahead (market)
DH	District Heating
ENS	Energy not served
ENTSO-E	European Network of Transmission System Operators
EPC	Engineering, procurement, and construction company
GAMS	General Algebraic Modeling System
HNS	Heat not served
HP	Heat Pump
LCOE	Levelized cost of (electric) energy
LCOH	Levelized cost of heat
mFRR	Manual Frequency Restoration Reserve
MILP	Mixed Integer Linear Programming
INECP	Spain's Integrated National Energy and Climate Plan 2023-2030
OPEX	Operating expenditures
PHS	Pump Hydro Storage
PPU	Power Production Unit
p.u.	Per unit
RISE	Research Institutes of Sweden
TDC	Total Direct Cost
TIC	Total Indirect Cost

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1 Introduction

This deliverable presents the integration of BTC in the electricity and heat sectors in the Spanish and Swedish systems. For this purpose, the BTC is simulated to compete on equal footing with other technologies that provide heat and electricity. The analysis was performed in an existing openTEPES model [2] which has been updated to include details on heat demand, BTC technological parameters and other heat-producing units (e.g., heat pumps, conventional CHPs, and boilers). The analysis is performed for Spain in 2030 and 2050 scenarios, while for Sweden, it is performed for 2035 and 2045, following both countries' National Climate and Energy Plans.

The main objectives of the analysis are the following:

1. Emulate the expansion and operation of the electricity system in future scenarios
2. Evaluate if the performance of the BTC in the future electricity system with high renewable and non-dispatchable sources is competitive.
3. Evaluate competition with alternative sources such as hydropower with storage capacity and pumped hydro or battery technologies

The deliverable is structured as follows:

1. Section 2 presents the methodology followed by the analysis, the input parameters used and the definition of the key performance indicators
2. Section 3 presents the Spanish case study, including the assumptions for the different scenarios, results and the sensitivity analyses performed
3. Section 4 presents the Swedish case studies, the input data, results and sensitivity analyses
4. Section 5 presents the main conclusions of the deliverable for both case studies

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2 Methodology

This section presents the description of the openTEPES model, the main developments including description of heat-demand and heat-producing technologies, and the definition of the key performance indicators used in the analysis.

2.1 OpenTEPES model

The open-access model openTEPES [2] is selected as a forecasting tool. This model, originating from the TEPES model (Transmission Expansion Planning for an Electric System) by Universidad Pontificia Comillas, is designed to optimize the total cost of a large-scale electric system at a strategic planning level.

Its core objective is to reduce capital expenses (costs associated with generation, storage, and transmission investments) and expected variable operational costs (such as those from emissions, fuels, maintenance, and ramp rates). Additionally, it accounts for costs related to reliability, specifically energy and heat not supplied (ENS and HNS), in its calculations. The digitalization costs have not been considered for all technologies and those costs do not differ significantly by technology.

As both a forecasting tool and a decision support system, openTEPES can simultaneously identify the most efficient generation and expansion strategies, meeting multiple criteria. The complete model documentation is available in [3]. The full mathematical formulation is presented in Annex 1.

Developed using Python 3.7.4 and Pyomo 5.6.6, openTEPES facilitates its input and output processes through .csv files. It uses Gurobi 8.1 as its default mixed-integer programming (MIP) solver.

2.2 Modelling of heat system in OpenTEPES

OpenTEPES has been updated to include the heating system specifically for the Bio-FlexGen project. For this purpose, hourly heat demand and heat network data have been included in the model. In addition, the following heat technologies have been modelled:

- **Fossil fuel boiler** (Fuel to Heat): consumes any fuel other than hydrogen to produce heat.
- **Combined heat and power** (Cogeneration, including BTC): consumes fuel to produce heat and electricity.
- **Electric boiler** (Power to Heat): consumes electricity to produce heat.
- **Hydrogen boiler** (Hydrogen to Heat): consumes hydrogen to produce heat.
- **Heat Pump** (Power to Heat): consumes electricity to produce heat. Internally, the model treats heat pumps the same as electric boilers.
- **Heat Not Served**: represents the volume of heat demand not satisfied by the generation mix.

The main parameters related to the heat system are presented in Table .

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Table 1: Heat-related parameters in openTEPES

Parameter	Description	Unit
Heat Demand	Heat demand in each node	GW
NTC	Net transfer capacity (total transfer capacity multiplied by the security coefficient) of a heat pipe	GW
HTNS Cost	Cost of heat not served (HTNS)	€/MWh
Maximum Power Heat	Maximum heat output (heat produced by a CHP at its maximum electric power, or by a fuel boiler)	MW
Minimum Power Heat	Minimum heat output (heat produced by a CHP at its minimum electric power, or by a fuel boiler)	MW
Production Function Heat	Production function from electricity to heat (only used for heat pumps and electric boilers)	kWh/kWh
Production Function H2 To Heat	Production function from hydrogen to heat (only used for hydrogen boilers)	kgH2/kWh

2.3 Key performance indicators

This section presents the key performance indicators used to analyse the system performance in Spanish and Swedish cases.

2.3.1 Total system cost

Total system cost (2.1) over the entire scheduling horizon is calculated as the sum of investment costs, generation and consumption operational costs (operation and maintenance and fuel costs), emissions costs, and reliability costs, which represent the costs associated to electricity and heat not served:

$$Total_{Cost}[MEUR] = (Investment + Generation + Consumption + Emissions + Reliability)_{Cost} \quad (2.1)$$

2.3.2 Proportion of renewable/fossil fuel generation

For both electricity and heat, the proportion of annual renewable and fossil generation over the total dispatch volumes is calculated as follows:

$$Renewable_{Generation}[\%] = \frac{\sum_{Renewable\ technologies} Dispatch\ volumes}{Total\ dispatch\ volumes} \quad (2.2)$$

$$Fossil_{Generation}[\%] = \frac{\sum_{Non\ renewable\ technologies} Dispatch\ volumes}{Total\ dispatch\ volumes} \quad (2.3)$$

Additionally, a proportion of electrified heat generation (2.4) is calculated, representing the ratio of heat dispatch volumes produced by electric boilers and heat pumps:

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$$Electrified_{Heat\ Generation}[\%] = \frac{\sum_{Electric\ boilers\ +\ Heat\ pumps} Dispatch\ volumes}{Total\ dispatch\ volumes} \quad (2.4)$$

2.3.3 Carbon Emissions

Total carbon emissions from the generation dispatched are calculated by the model using fossil carbon emissions rates associated with each fossil fuel (2.5) and quantifies the total embodied carbon per MWh of generation from fossil origin. The total emissions are calculated as follows:

$$Carbon\ Emissions_{Total}[ton_{CO_2}] = \sum_{Generators} Emission\ Factor^{CO_2}_{Generator}.\ Dispatch\ volume_{Generator} \quad (2.5)$$

2.3.4 Resulting Electricity Marginal Cost

The electricity marginal costs result from the demand and supply equality constraint or power balance equation. As the model performs investment decisions, the resulting prices include the prices needed to recover the investment costs and operational costs.

2.3.5 Investments in technologies providing electricity and/or heat

For all candidate generators and storage units considered, the respective investment decisions are informed by the model in capacity units [MW] of electric and thermal power, as applicable.

2.3.6 Electricity and heat generation by technology

The model reports electricity and heat dispatch volumes in GWh units. Results are available both per generator and aggregated by technology.

2.3.7 Electricity curtailment by technology

Electricity curtailment volumes are informed by the model in GWh. Results are available both per generator and aggregated per technology.

2.3.8 LCOE and LCOH by technology

Levelized costs of electricity (LCOE) and heat (LCOH) are informed by the model in EUR/MWh per unit. Results are aggregated per technology, only if that technology receives investment from a candidate generator. These values measure the net present investment cost and operational costs divided by the annual dispatch volume.

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3 Spanish case

This section presents the Spanish case studies. First, the heat and electricity demand considered are presented, then, the input data specific to the Spanish cases, the results for the simulations for 2030 and 2050, and finally, the sensitivity analyses are added.

The openTEPES model was used to allow the expansion of only heat generation and electric storage capacities, without the possibility of making investments in power lines or electric generating units, besides cogeneration technologies. For all candidate units, a fixed-charge interest rate of 7% is used to annualize the overnight investment cost. All investment decisions are considered continuous from the point of view of the mathematical optimization, meaning it can adopt values from 0 to the maximum capacity established as input.

3.1 Heat sector

For the model to correctly compute the heat balance, the demand data profile must have an hourly resolution. Obtaining the heat demand for future scenarios with an hourly resolution is not a straightforward task, as no precise or reliable data is available disaggregated by hours. Therefore, it is necessary to make a series of assumptions as realistic as possible.

The main assumptions considered for obtaining the heat demand in the Spanish cases are:

1. Only industrial heat demand is modelled, as the Spanish use cases studied in this work package are industry-related only.
2. Within the industrial heat demand, only low-temperature heat demand (<100°C) is considered, as the main objective of this task is to study the competitiveness of BTC against other industrial heat technologies in a country-system level. Additionally, the BTC can provide heat within this temperature range only (without auxiliary boiler or heat pump).
3. Yearly industrial heat demand is assumed to remain constant throughout both future scenarios, 2030 and 2050. While there is no available forecast for the industrial sector growth, it is assumed that it remains constant. Consequently, the respective heat demand also remains constant.

Firstly, Spanish total yearly industrial heat demand is taken from “Heatmap of Spain” [4], a tool developed by the Ministry for the Ecological Transition and the Demographic Challenge that geographically locates estimated heat demand values from consumers in different industrial sectors. The available data corresponds to 2019 and is disaggregated by NUTS-2 level (autonomous communities) and by type of industry branch, namely: food, beverages and tobacco; mining; mineral processing; paper production; basic chemicals; metal production; non-ferrous metals; machinery, and others.

Secondly, a relative share for each heat temperature level with respect to the total heat demand in each of the industry branches is taken from [5] to obtain the demand corresponding to the low-temperature range of heat provision. This paper considers three temperature levels: low ($T<100°C$), medium ($100°C \leq T < 400°C$), and high ($T \geq 400°C$).

Then, data is taken from Enagas [6], Spain’s gas transmission system operator, to extract 2019’s daily shares of natural gas demand in the industry sector. The low-temperature heat demand is assumed to follow this same daily profile in all NUTS-2 components.

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Finally, the 2017 Spanish industrial electricity demand profile is taken from [7] in hourly resolution to construct the hourly low-temperature heat demand profile. The correction of the first calendar day had to be done to fit the data into the 2019 heat demand profile.

The 2019 hourly low-temperature industrial heat demand profile for Spain is then obtained disaggregated by NUTS-2 levels. As mentioned above, this same profile is used for both 2030 and 2050 scenarios. The resulting profile for mainland Spain (all peninsular autonomous communities summed) is shown in Figure 1.

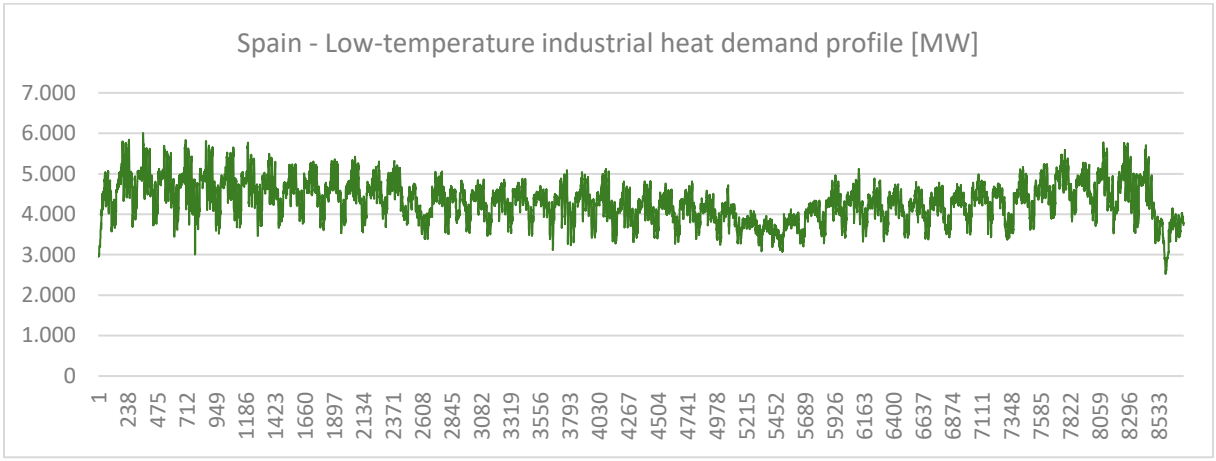

Figure 1: Hourly heat demand profile - Spanish cases

3.2 Electricity Sector

A single-node-system was assumed for the Spanish cases, considering an infinite capacity of interconnection of all lines. The system does not contemplate international exchanges, following the reasoning of establishing a worst-case-scenario, in which the system cannot benefit from imports or exports. Thus, the Spanish electricity system considered is an "electrical island".

The constraints that the system must satisfy are the following:

- Energy balance at each node of the network [GW]
- Evaluation of the inventory of all storage technologies [GWh]
- Instantaneous power above the technical minimum [p.u.]: verification that the maximum power of the thermal units is not exceeded.
- Availability of demand side management [GWh]
- Charging/discharging and generation of storage and production units [GWh]
- Relation between start-up, commitment and shutdown of thermal units [p.u.]
- Ramps [p.u.]: verification that the production ramps up or down thermal or hydraulic units are not exceeding limits.

Thus, with the annualized investment cost of the candidate technologies and the aforementioned restrictions, the least costly solution for the system is determined.

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3.2.1 2030 scenarios

Spain's 2023 draft update version of its Integrated National Energy and Climate Plan (INECP 2023-2030) [16] is used as the main data source for modelling 2030's Spanish electric system. INECP 2023-2030 sets ambitious targets consistent with the emission reduction goals adopted at the European level. The targets for 2030 are:

- 32% reduction in greenhouse gas emissions compared to 1990 levels
- 48% of final energy use from renewable sources
- 44% improvement in energy efficiency in terms of final energy consumption
- 81% of renewable energy in electricity generation (mainly solar PV and wind sources)
- Reduction of energy dependency to 51%

The plan emphasizes local-level distributed generation and energy efficiency, promoting investment and job creation. It includes measures to enhance energy security by reducing fossil fuel imports and increasing self-sufficiency. It also encourages citizen participation through own consumption, demand management, and local energy communities, ensuring a proactive role in the energy transition.

The following data and assumptions are taken from the INECP and used for modelling the 2030 case:

1. Electricity demand (including self-consumption): 316.5 TWh, with a peak demand of 51.447 GW. Note that only the demand of the peninsular system is given, which means that the Balearic Islands, Canary Islands, Ceuta and Melilla are not included in the Plan and, therefore, are not included in this study.

   In order to account for the total electricity consumption of electrolyzers and electric vehicles, which sum 52 TWh and 5.6 TWh based on [9], the final electricity demand for the 2030 scenario is then **258.9 TWh**. The profile used has been extrapolated from the 2015 peninsular demand and is shown in Figure 2:

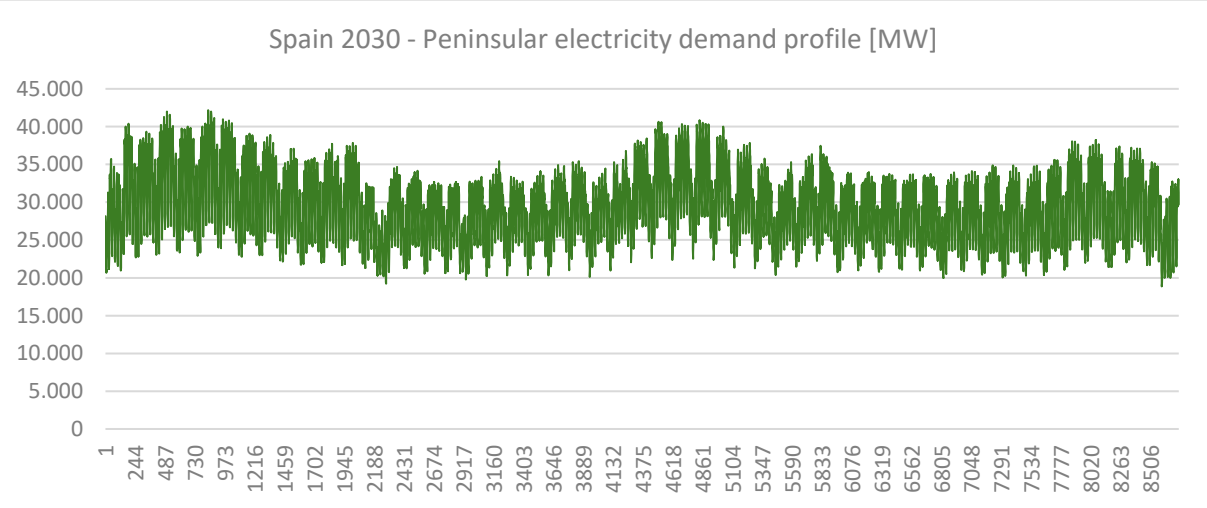

Figure 2: Electric power demand profile - 2030 Spanish cases

2. Installed capacity and generation mix: as informed in Table .

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Table 2: INECP's Installed capacity and generation for 2030 Spanish peninsular electric system

Technology	MW	GWh
Onshore wind	57,522	116,970
Offshore wind	2,800	9,769
Solar PV	72,751	127,212
Solar thermal	4,804	9,470
Hydropower *	14,562	28,941
Nuclear	3,041	34,573
Combined cycle	24,500	16,516
Cogeneration	4,071	19,356

*No pumped storage considered

3. Fuel prices and emission factors: as informed in Table 3.

Table 3: Fuel prices and CO_2 emission factors used in 2030 Spanish scenario

Fuel type	Fuel price [EUR/GJ]	Emission factor [tCO_2/MWh]
Natural gas	10.92	0.34
Coal	3.01	0.85
Oil	14.64	0.80
Nuclear	0.47	0.00
Hydrogen (1)	17.60	0.00
Biomass (2)	2.70	0.00

Note (1): Hydrogen price data was not extracted from the INECP, but from ENTSO-E and ENTSOG's Ten-Year Network Development Plan (TYNDP) 2024 [10].

Note (2): Biomass price data was also not extracted from the INECP. Using the 2021 Spanish biomass price from Deliverable 3.6 as initial price, the same proportion of price reduction in natural gas between 2030 and 2023 as informed by ENTSO-E [10] was considered.

4. CO_2 emissions price: 76.04 EUR/tonCO_2.

3.2.2 2050 scenarios

The Ten-Year Network Development Plans (TYNDP 2024) [9], drawn up by the European Networks of Transmission System Operators for Electricity and Gas (ENTSO-E and ENTSO-G), are used as the main data source for modelling 2050's Spanish electric system. These plans were developed to support Europe's goal of achieving climate neutrality by 2050. It complements national grid plans, ensuring cost-effective and secure energy transitions with increased share of renewables and higher efficiency.

The following data and assumptions are taken from TYNDP 2024 and used as input for modelling the 2050 Spanish electric system:

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1. Electricity demand for the peninsular system (including self-consumption): **376 TWh**. In this case, electrolyzers and electric vehicles total consumption is already considered. The same demand profile as the 2030 scenario is considered (Figure 3):

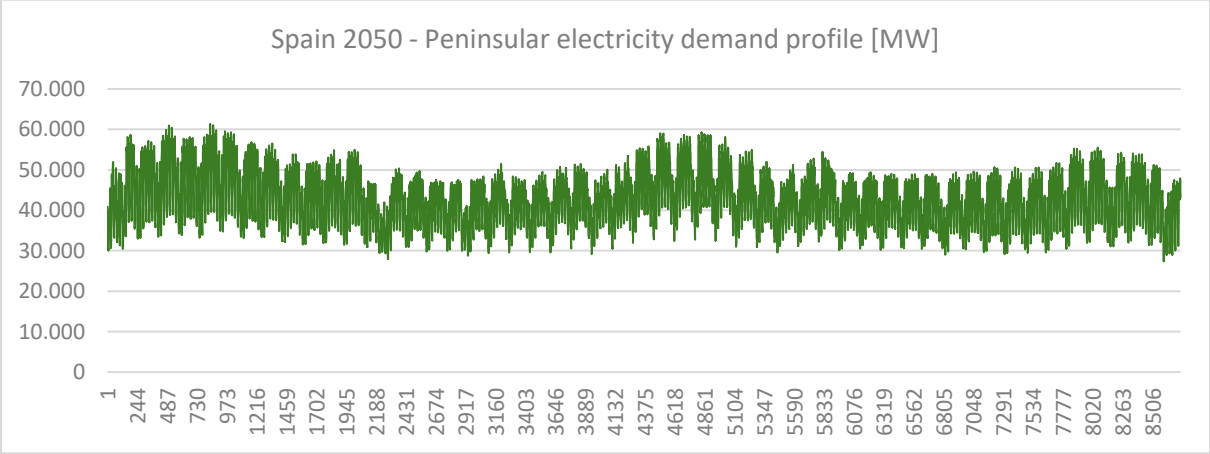

Figure 3: Electric power demand profile – 2050 Spanish cases

2. Installed capacity and generation mix: as informed in Table 4.

Table 4: TYNDP's Installed capacity and generation for 2050 Spanish peninsular electric system

Technology	MW	GWh
Onshore wind	104,000	266,000
Offshore wind	11,000	45,000
Solar PV	179,000	290,000
Solar Thermal	12,000	19,000
Hydropower *	14,000	23,000
Combined cycles	15,000	1,400

* No pumped storage considered

3. Electrolyzers and electric vehicles consumption: the yearly electricity consumption forecasted for electrolyzers and electric vehicles are 171 TWh and 68 TWh, respectively.

4. Fuel prices: as informed in Table 5.

Table 5: Fuel prices used in 2050 Spanish scenarios (reference?)

Fuel type	Fuel price [EUR/GJ]
Hydrogen	15.10
Biomass	2.15

Note that, since 2050 is considered a net-zero carbon emission scenario, no fossil fuels are included. Again, the biomass price data was not extracted from the TYNDP 2024. The same proportion of price reduction in natural gas between 2050 and 2023 was considered.

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3.3 Specific input data

The following data and assumptions are common for both 2030 and 2050 scenarios:

- **Biomass availability**: based on a study by the European Commission [11], the biomass availability for energy uses in Spain sums 5,614 ktons in dry matter (latest available data – no year specified, but post 2020). The study also gives values for biomass availability for unknown uses, summing 31,672 ktons.

  Considering an average lower calorific value of 18.985 MJ/kg, the energetic content associated to biomass availability for energy uses results in 29.6 TWh, yearly. Assuming that this value remains constant for both 2030 and 2050 scenarios, and that all of it is used as feedstock for BTC technology only, a maximum investment capacity for BTC can be obtained. Considering that, if installed, BTC could be committed around 80% of the year, that would give a maximum capacity of (rounding up) 1,500 MWth (and the corresponding electric capacity for 2030 and 2050 for the selected BTC scale).

  It is assumed that the remaining technologies having biomass as fuel consume the biomass categorized as "for unknown uses". Having in consideration that the main purpose of this study is to investigate the competitiveness of BTC against other heat and cogeneration technologies in future scenarios, the same value of maximum thermal capacity (1,500 MWth) is used for all the remaining technologies, with the following exceptions:

  - Heat pumps and electric boilers in 2050 scenarios: since low-temperature industrial heat is expected to be electrified in Spain by 2050 [8], a maximum capacity of 3,000 MWth is set for these technologies, so that the model has at least the chance to cover all heat demand with these two technologies.
  - Biomass CHP in baseline scenarios (without BTC): a maximum capacity of 3,000 MWth is set in order to account for biomass availability when no BTC technology is considered.

- **Technical characterization of BTC**: all technical data, including CAPEX (investment and fixed operation and maintenance costs), electric and thermal efficiencies, and electric power to heat ratio are taken from a replicability study made by Phoenix, for both 2030 and 2050 scenarios. Because all candidate technologies are modelled in an aggregated way, it was decided to use BTC data corresponding to the maximum scale available, P100 (100 MW electric power), with forest residues pelleted on-site as fuel type. Data used as input in the model are presented in Table 7, Table 8 and Table 9.
- Technical characterization of heat and CHP technologies: all technical data, including CAPEX (investment and fixed operation and maintenance costs), electric and thermal efficiencies, are taken from [12] and [13] (only for hydrogen boilers). For 2030 scenarios, data corresponding to 2010 is used. As no data regarding ramps, minimum up- or down times, or variable OPEX were available, the study did not consider them. Again, all heat and CHP technologies are modelled aggregately, meaning any continuous capacity rather than individual units. Data used as input in the model are presented in Table 7, Table 8 and Table 9.

- **Demand side management:** 3 manageable demand segments are considered: commercial, industrial and residential. The volume of each segment has been determined using the following assumptions:

  - Commercial: a manageable demand is assumed with a volume of 10% over the total and a maximum displacement of 1h.

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- Industrial: 10% of the demand is assumed to be manageable, with a maximum displacement of 1h.
- Residential: 24% of the total residential demand is considered manageable, with a maximum displacement of 6h.

- **Electric vehicles:** two possible behaviors have been considered for electric vehicle charging: fixed charging and smart charging. Each of them is associated with 50% of the annual demand volume. Fixed charging is based on data provided by the European Resource Adequacy Assessment (ERAA) [14]. The smart charging profile responds to the marginal costs determined by the optimization problem, charging cars when they are lower.

- **Electrolyzers:** the overall electricity demand associated with electrolyzer operation is segmented by week, meaning that every week, the same volume of electricity consumption, thus hydrogen production, is satisfied.

- **Energy and heat not served:** 10,000 EUR/MWh is set as cost, being higher than 7,000 EUR/MWh used in [14].

3.3.1 2030 scenarios

This section contains the characterization of candidate technologies considered in the 2030 scenarios.

- Candidate storage technologies: characteristics of candidate storage technologies are presented in Table 6.

Table 6: Input data for storage technologies considered in 2030 scenarios. Sources: [15], [16].

Technology	Max Power [MW]	Storage [GWh]	Efficiency [p.u.]	CAPEX [M€]
Batteries (4 hours)	4,000	16	0.90	4,452
Closed Loop PHS (aggregated)	6,387	133	0.75	4,619

- Candidate heat production technologies:

Table 7: Input data for heat and CHP technologies considered in 2030 scenarios

Technology	El. Power [MW]	Heat Power [MW]	El. Charge [MW]	Fuel Cost [€/Gcal]	Linear Term (1) [Gcal/MWh]	CAPEX [M€]
CHP Gas	1,159	1,500	-	45.50	1.10	1,130.1
CHP Biomass	158	1,500	-	11.27	1.37	464.2
BTC	2,373	1,500	-	11.27	1.07	7,594.0
Boiler Gas	-	1,500	-	45.50	1.08	50.0
Boiler Coal	-	1,500	-	12.54	1.30	65.8
Boiler Biomass	-	1,500	-	11.27	1.46	82.8

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Boiler Oil	-	1,500	-	61.00	1.12	37.5
Boiler H2 (2)	-	1,500	-	73.33	1.00	4,955.0
Boiler Electric (3)	-	1,500	1,785.71	-	-	34.1
Heat Pump (3)	-	1,500	506.76	-	-	411.9

Note (1): The linear term parameter represents the ratio from fuel consumption [Gcal] to heat (and electricity, if applicable) production [MWh].

Note (2): A value of 0.025 kgH2/kWh is set as the ratio from hydrogen consumption to heat production.

Note (3): The values considered as ratio from electricity consumption to heat production for electric boiler and heat pumps are, respectively, 1.19 and 0.338 kWh/kWh.

3.3.2 2050 scenarios

This section contains the characterization of candidate technologies considered in the 2050 scenarios.

- Candidate storage technologies: characteristics of candidate storage technologies are presented in Table 8.

Table 8: Input data for storage technologies considered in 2050 scenarios. Sources: [15], [16].

Technology	Max Power [MW]	Storage [GWh]	Efficiency [p.u.]	CAPEX [M€]
Batteries (4 hours)	4,000	16	0.94	1,484
Closed Loop PHS (aggregated)	2,919	50.2	0.75	2,460

- Candidate heat production technologies:

Table 9: Input data for heat and CHP technologies considered in 2050 scenarios

Technology	El. Power [MW]	Heat Power [MW]	El. Charge [MW]	Fuel Cost [€/Gcal]	Linear Term [Gcal/MWh]	CAPEX [M€]
CHP Gas	1,404	1,500	-	20.83	0.95	1,263.9
CHP Biomass	930	1,500	-	8.95	1.06	1,904.2
BTC	2,651	1,500	-	8.95	1.00	4,933.8
Boiler Gas	-	1,500	-	20.83	1.05	50.0
Boiler Coal	-	1,500	-	6.25	1.27	65.8
Boiler Biomass	-	1,500	-	8.95	1.43	82.8
Boiler Oil	-	1,500	-	37.50	1.08	37.5
Boiler H2 (1)	-	1,500	-	62.92	1.00	4,504.5
Boiler Electric (2)	-	3,000	3,529.42	-	-	68.2
Heat Pump (2)	-	3,000	869.56	-	-	823.7

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grand agreement N° 101037085.

Note (1): A value of 0.025 kgH2/kWh is set as the production rate from hydrogen consumption to heat production.

Note (2): The values considered as production rate from electricity consumption to heat production for electric boiler and heat pumps are, respectively, 1.176 and 0.290 kWh/kWh.

3.4 Results

This section presents the results of the Spanish cases for 2030 and 2050. Cases comprise, first, a baseline scenario without the inclusion of BTC technology, and then, a scenario with BTC. Sensitivities cases are then presented.

3.4.1 2030 scenarios

The 2030 results compare the modeling in openTEPES of the Spanish INECP for 2023-2030 [1] scenario without BTC with the scenario with BTC. As the Spanish INECP does not disaggregate between storage technologies nor heat production technologies, the investments need to be simulated to account for them and compare the potential for BTC.

1. **Baseline scenario (without BTC)**

Without considering BTC, Table 10 shows the investment results in storage technologies (batteries and closed-loop pump hydro storage) and heat-producing technologies.

Regarding storage technologies, the model decides to invest only in PHS. Gas and biomass CHP are invested at full capacity, as well as electric boilers. Biomass boilers, and then heat pumps, follow as heat-generating technologies. Note that carbon-emitting units are neither selected for investment nor hydrogen boilers, with the highest CAPEX among boiler technologies.

Table 10 Investments in storage and heat technologies in the Spanish 2030 scenario without BTC

Technology	Investment El. [MW]	Investment Heat [MW]	LCOE [EUR/MWh]	LCOH [EUR/MWh]
Candidate Units				
Batteries	0	-	-	-
Closed Loop PHS (new)	4,612	-	33.7	-
CHP Gas	1,159	1,500	12.8	9.9
CHP Biomass	316	3,000	25.7	2.7
BTC	0	0	-	-
Boiler Biomass	-	1,211	-	1.6
Boiler Coal	-	0	-	-
Boiler Electric	-	1,500	-	1.1
Boiler Gas	-	0	-	-
Boiler H2	-	0	-	-
Boiler Oil	-	0	-	-
Heat Pump	-	188	-	7.0

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Table 11 shows the generation, consumption, curtailment and emissions by technologies. Wind and solar are the main electricity generation technologies; all renewable technologies account for 86% of total generation. In the case of low-temperature heat generation, the percentage is 72%.

Figure 4 presents the system heat balance for the whole year. Note that during the spring and beginning of the summer season, when renewable generation increases, the model decides to decrease gas CHP production and increase consumption in the electric boiler, as well as biomass technologies.

Table 11 Generation by technologies in the Spanish 2030 scenario without BTC

Technology	Electricity Gen [GWh]	Electricity Cons [GWh]	Curtailment [GWh]	Heat Gen [GWh]	Emissions [MtCO2]
Non-candidate units					
Onshore wind	117,002	-	0	-	-
Offshore wind	9,339	-	1,258	-	-
Solar PV	125,012	-	7,139	-	-
Solar Thermal	5,029	-	-	-	-
Hydropower (no PHS)	13,445	-	334	-	-
Open Loop PHS	11,431	-5,945	-	-	-
Closed Loop PHS	5,003	-6,671	-	-	-
Nuclear	26,035	-	-	-	-
CCGT	12,891	-	-	-	6.445
Electrolyzers	-	-52,000	-	-	-
Electric Vehicles	-	-5,596	-	-	-
Candidate Units					
Batteries	0	0	-	-	-
Closed Loop PHS (new)	6,059	-8,079	-	-	-
CHP Gas	6,171	-	-	7,986	2.098
CHP Biomass	2,529	-	-	24,021	-
BTC	0	-	-	0	-
Boiler Biomass	-	-	-	2,932	-
Boiler Coal	-	-	-	0	-
Boiler Electric	-	-2,582	-	2,170	-
Boiler Gas	-	-	-	0	-
Boiler H2	-	-	-	0	-
Boiler Oil	-	-	-	0	-
Heat Pump	-	-175	-	519	-

	Renewable [%]	Fossil [%]	Electric [%]
Electricity Gen	86.3%	13.7%	-
Heat Gen	71.6%	21.2%	7.1%

System costs without BTC account for almost 74% of operational costs (fuel costs), 13% of investment costs, and 23% of emission costs (Table 12).

Table 12 Spanish system costs result without BTC 2030

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Cost Type	[MEUR]
Investment Cost	359
Generation Operation Cost	1,755
Consumption Operation Cost	38
Emission Cost	650
Reliability Cost	0
Total System Cost	2,802

2. Scenario with BTC

When BTC is considered, BTC reduces investments in biomass boilers and closed-loop PHS and increases investments in heat pumps (see Table).

Table 13 Investments in storage and heat technologies in the Spanish 2030 scenario with BTC

Technology	Investment El. [MW]	Investment Heat [MW]	LCOE [EUR/MWh]	LCOH [EUR/MWh]
Candidate Units				
Batteries	0	-	-	-
Closed Loop PHS (new)	3,247	-	29.1	-
CHP Gas	1,159	1,500	17.2	13.3
CHP Biomass	158	1,500	26.4	2.8
BTC	2,373	1,500	35.3	55.8
Boiler Biomass	-	481	-	3.7
Boiler Coal	-	0	-	-
Boiler Electric	-	1,500	-	0.7
Boiler Gas	-	0	-	-
Boiler H2	-	0	-	-
Boiler Oil	-	0	-	-
Heat Pump	-	1,298	-	4.5

BTC significantly impacts the total generation mix, reducing the generation of CCGT by replacing more than 15 TWh of electric generation and reducing conventional cogeneration. On the other hand, BTC favours generation from existing closed-loop pump hydro storage.

Since BTC consumes a renewable fuel, renewable electricity generation increases from 86% to 89%. Renewable heat changes from 72% to 58%, while electric heat increases from 7% to 26%.

Table 14 Generation by technologies in the Spanish 2030 scenario with BTC

Technology	Electricity Gen [GWh]	Electricity Cons [GWh]	Curtailment [GWh]	Heat Gen [GWh]	Emissions [MtCO2]
Non-candidate units					
Onshore wind	117,002	-	0	-	-
Offshore wind	9,294	-	1,304	-	-
Solar PV	124,545	-	7,606	-	-
Solar Thermal	5,070	-	-	-	-

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Hydropower (no PHS)	13,422	-	357	-	-
Open Loop PHS	11,433	-5,947	-	-	-
Closed Loop PHS	5,432	-7,243	-	-	-
Nuclear	26,035	-	-	-	-
CCGT	4,567	-	-	-	2.284
Electrolyzers	-	-52,000	-	-	-
Electric Vehicles	-	-5,596	-	-	-
Candidate Units					
Batteries	0	0	-	-	-
Closed Loop PHS (new)	4,804	-6,406	-	-	-
CHP Gas	4,608	-	-	5,963	1.567
CHP Biomass	1,232	-	-	11,705	-
BTC	15,059	-	-	9,520	-
Boiler Biomass	-	-	-	504	-
Boiler Coal	-	-	-	0	-
Boiler Electric	-	-4,268	-	3,587	-
Boiler Gas	-	-	-	0	-
Boiler H2	-	-	-	0	-
Boiler Oil	-	-	-	0	-
Heat Pump	-	-2,145	-	6,347	-

The case with BTC reduces the total system costs by 19% (Table 15), even if investment costs increase by 127%, operation and emission costs reduce by 36% and 55%, respectively.

Table 15 Spanish system costs results with BTC 2030

Cost Type	[MEUR]
Investment Cost	816
Generation Operation Cost	1,125
Consumption Operation Cost	36
Emission Cost	293
Reliability Cost	0
Total System Cost	2,270

Figure 5 shows the operation of heat generation technologies with BTC. Comparing these results with those of the previous case (Figure 4), both biomass CHP and boiler heat generation decrease. Note that most of the hours during which BTC operates (more than 70% of the year), it is generating at full capacity. Whenever electricity prices are low (renewable generation is maximum), gas CHP (and BTC) production is replaced by electric boilers and heat pumps. This behaviour is also reflected in Figure 6, containing the resulting marginal costs for both cases. As shown in the figure, BTC lowers the expected electricity prices (marginal costs).

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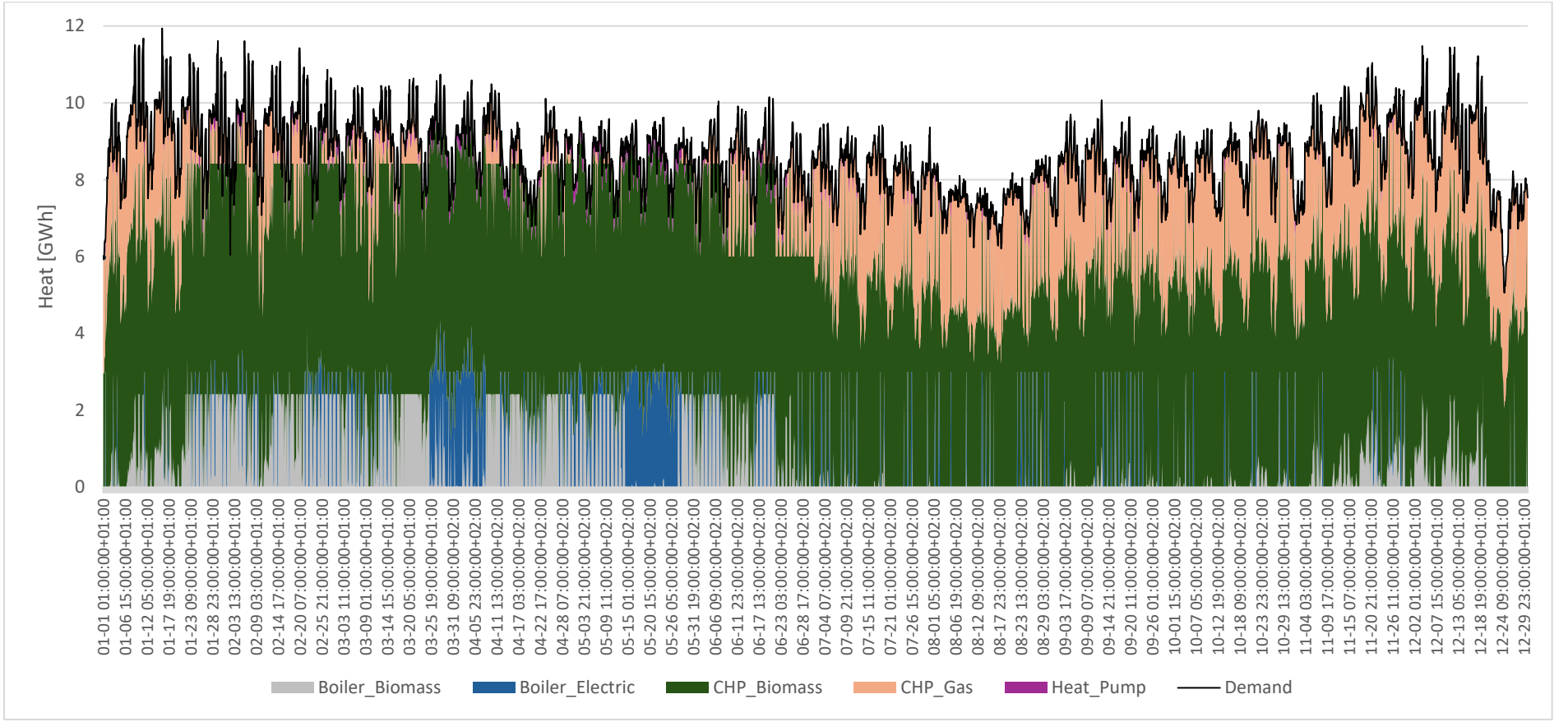

Figure 4: Heat-balance Spain 2030 without BTC

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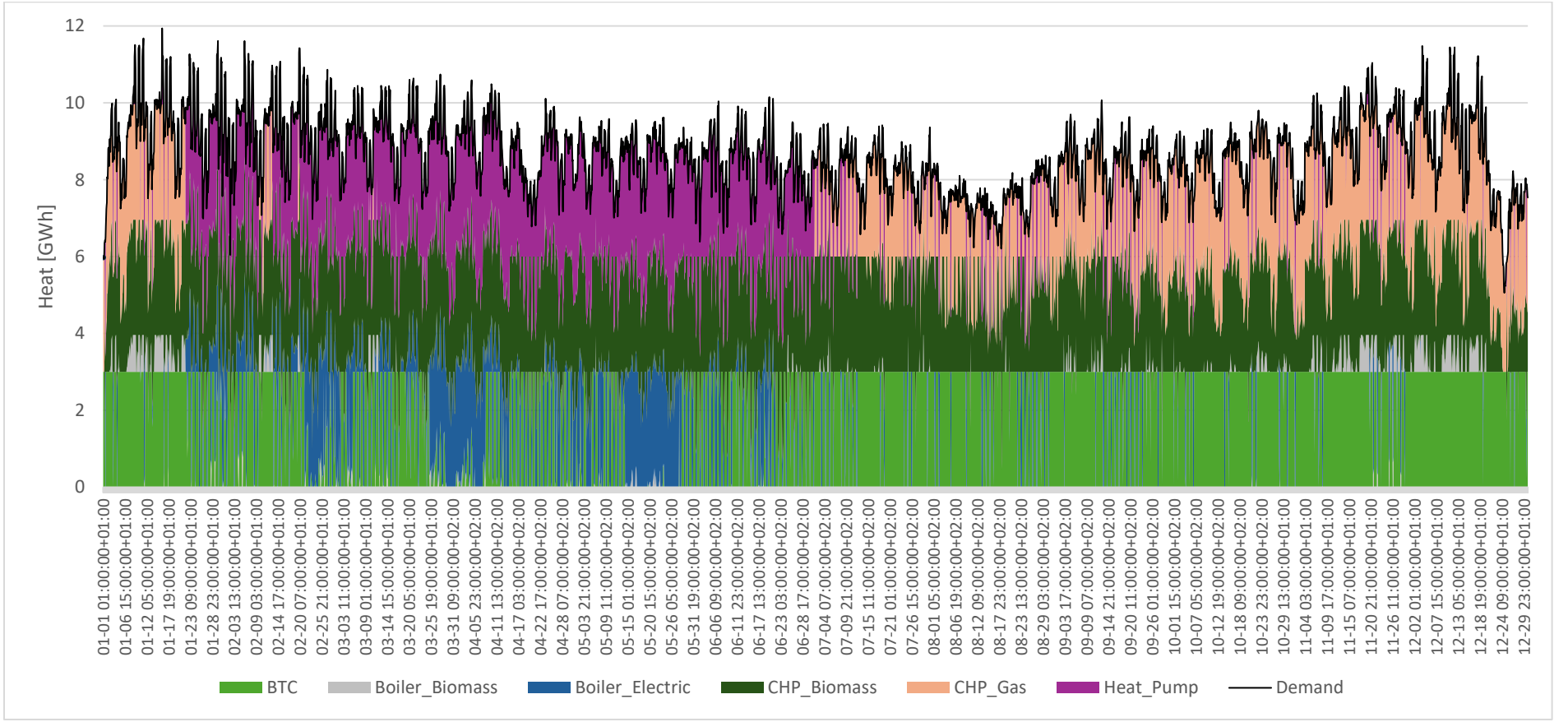

Figure 5: Heat-balance Spain 2030 with BTC

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grand agreement N° 101037085.

Figure 6: Electricity marginal costs, Spain 2030 scenarios

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3.4.2 2050 scenarios

1. Baseline scenario (without BTC)

Table 16 shows the simulation investment results without considering BTC. In this case, all heat producer technologies are invested to supply the considered heat demand at optimal cost, except for hydrogen boilers.

Table 16 Investments in storage and heat technologies in the Spanish 2050 scenario without BTC

Technology	Investment El. [MW]	Investment Heat [MW]	LCOE [EUR/MWh]	LCOH [EUR/MWh]
Candidate Units				
Batteries (new)	4,000	-	32.5	-
Closed Loop PHS (new)	1,000	-	123.5	-
CHP Biomass	1,429	2,305	33.6	20.8
BTC	0	0	-	-
Boiler Biomass	-	1,500	-	8.6
Boiler Electric	-	2,728	-	0.5
Boiler H2	-	0	-	-
Heat Pump	-	2,154	-	2.3

Table 17 shows technologies' heat and electricity generation results in the Spanish 2050 scenario without BTC. The technology that produces the most heat is the heat pump, followed by traditional biomass CHP and boilers, while electric boilers produce significantly less volumes. In 2050, 100% of the electricity is expected to be renewable, heat production with biomass reaches 28%, and 72% comes from electric devices. Notice that for 2050, it was optimal to leave a small volume of electricity non-served having a limited impact in the system cost.

Figure 8 shows the heat balance results. During hours of decreased renewable generation (winter season), when electricity prices are higher, biomass CHP and boiler production increase, while the consumption of electric devices (electric boilers and heat pumps) decreases.

Table 17 Generation by technologies in the Spanish 2050 scenario without BTC

Technology	Electricity Gen [GWh]	Electricity Cons [GWh]	Curtailment [GWh]	Heat Gen [GWh]
Non-candidate units				
Onshore wind	266,002	-	0	-
Offshore wind	28,700	-	16,301	-
Solar PV	279,585	-	10,424	-
Solar Thermal	15,104	-	-	-
Hydropower (no PHS)	13,459	-	320	-
Open Loop PHS	8,517	-2,059	-	-
Closed Loop PHS	3,682	-4,909	-	-
CC (biomass and H2)	17,256	-	-	-
Electrolyzers	-	-171,000	-	
Electric Vehicles	-	-68,001	-	

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Candidate Units				
Batteries (new)	3,197	-3,389	-	-
Closed Loop PHS (new)	372	-497	-	-
CHP Biomass	6,099	-	-	9,836
BTC	0	-	-	0
Boiler Biomass	-	-	-	677
Boiler Electric	-	-10,956	-	9,316
Boiler H2	-	-	-	0
Heat Pump	-	-5,161	-	17,798

	Renewable [%]	Fossil [%]	Electric [%]
Electricity Gen	100.0%	0.0%	-
Heat Gen	27.9%	0.0%	72.1%

ENS [GWh]	HNS [GWh]
0.49	0.00

Table 18 shows the Spanish system costs without BTC for the year 2050. Operation costs represent 65% of the costs, while investment costs represent 34%.

Table 18 Spanish system costs results without BTC for the year 2050

Cost Type	[MEUR/year]
Investment Cost	406
Generation Operation Cost	789
Consumption Operation Cost	16
Emission Cost	0
Reliability Cost	5
Total System Cost	1,216

2. Scenario with BTC

Under the assumptions considered, the model does not suggest investment in BTC technology. This scenario differs from the previous one as maximum CHP biomass capacity is limited by half to split with BTC technology in case the models invests in BTC. Therefore, this scenario becomes the reference base case to compare to sensitivities. Batteries are invested at the maximum capacity, as well as biomass CHP and boilers, followed by heat pumps and electric boilers (Table 19).

Table 19: Investments in storage and heat technologies in the Spanish 2050 scenario with BTC

Technology	Investment El. [MW]	Investment Heat [MW]	LCOE [EUR/MWh]	LCOH [EUR/MWh]
Candidate Units				
Batteries (new)	4,000	-	34.3	-
Closed Loop PHS (new)	1,618	-	111.2	-

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CHP Biomass	930	1,500	33.7	20.9
BTC	0	0	-	-
Boiler Biomass	-	1,500	-	8.1
Boiler Electric	-	1,941	-	0.5
Boiler H2	-	0	-	-
Heat Pump	-	2,947	-	2.3

Table 20 shows the generation, consumption and curtailment results for the 2050 scenario with limited CHP capacity. Heat pump operation increases to replace the higher volumes of biomass CHP production of the previous case, when a higher maximum capacity for that technology was considered. This can also be noted in Figure 8. Heat demand is more than 80% covered by electric boilers and heat pump.

The resulting marginal costs (Figure 9) are very similar to the previous case. The maximum value, 10,000 EUR/MWh, corresponds to the energy not served cost, but happens only in 4 hours.

Table 20: Generation by technologies in the Spanish 2050 scenario with BTC

Technology	Electricity Gen [GWh]	Electricity Cons [GWh]	Curtailment [GWh]	Heat Gen [GWh]
Non-candidate units				
Onshore wind	266,002	-	0	-
Offshore wind	28,028	-	16,972	-
Solar PV	278,605	-	11,404	-
Solar Thermal	14,911	-	-	-
Hydropower (no PHS)	13,432	-	346	-
Open Loop PHS	8,696	-2,298	-	-
Closed Loop PHS	4,077	-5,436	-	-
CC (biomass and H2)	19,381	-	-	-
Electrolyzers	-	-171,000	-	
Electric Vehicles	-	-68,001	-	
Candidate Units				
Batteries (new)	3,027	-3,208	-	-
Closed Loop PHS (new)	750	-1,001	-	-
CHP Biomass	3,950	-	-	6,371
BTC	0	-	-	0
Boiler Biomass	-	-	-	713
Boiler Electric	-	-6,715	-	5,710
Boiler H2	-	-	-	0
Heat Pump	-	-7,202	-	24,833

	Renewable [%]	Fossil [%]	Electric [%]
Electricity Gen	100.0%	0.0%	-
Heat Gen	18.8%	0.0%	81.2%

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ENS [GWh]	HNS [GWh]
0.95	0.00

Table 21: Spanish system costs results with BTC 2050

Cost Type	[MEUR]
Investment Cost	386
Generation Operation Cost	810
Consumption Operation Cost	18
Emission Cost	0
Reliability Cost	9
Total System Cost	1,224

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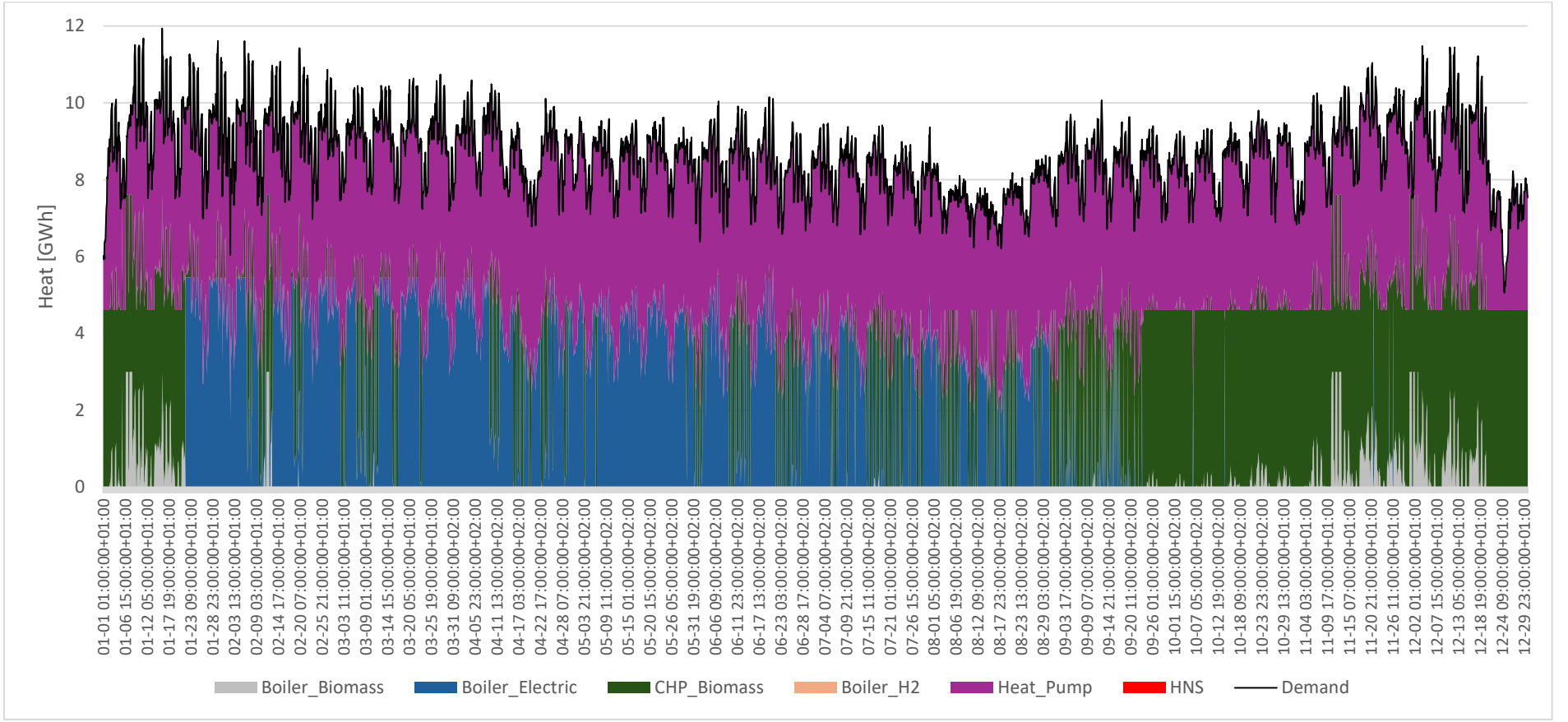

Figure 7: Heat-balance Spain 2050 without BTC

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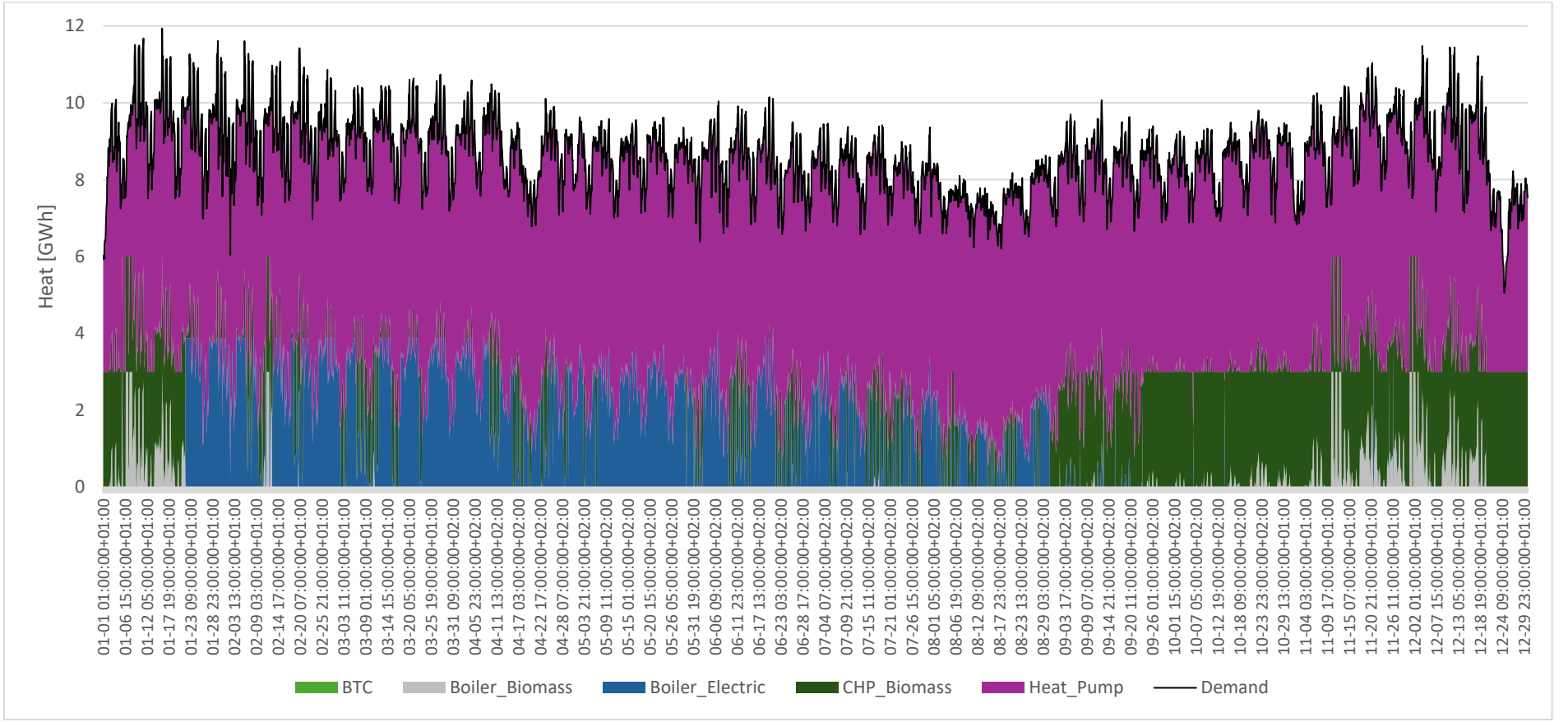

Figure 8: Heat-balance Spain 2050 with BTC

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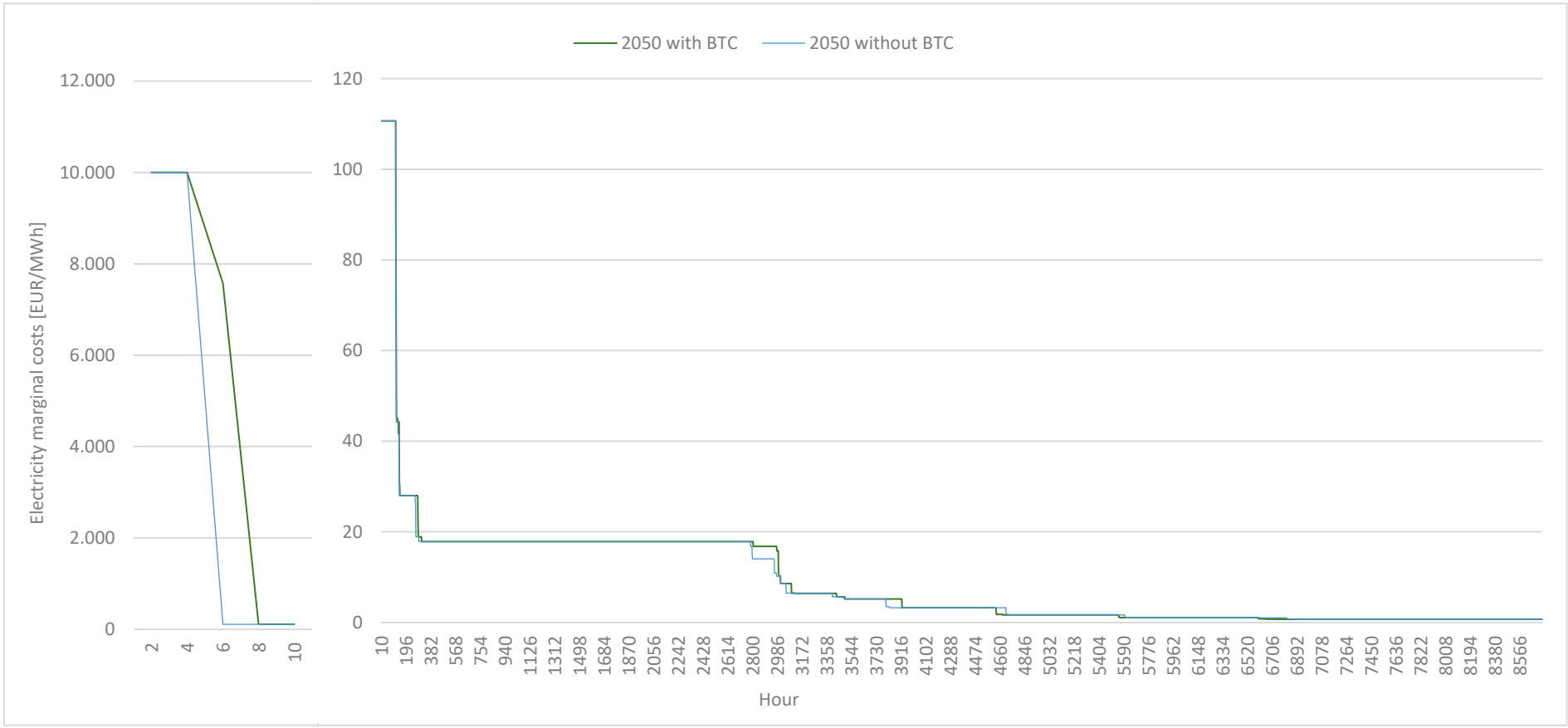

Figure 9: Electricity marginal costs, Spain 2050 scenarios

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3.5 Sensitivities analysis

This section compares the results obtained with additional sensitivities on key parameters for 2030 and 2050 scenarios. All discussions are based on comparisons between the cases with BTC and the sensitivities presented.

3.5.1 2030 scenarios

The three main parameters considered for 2030 are: biomass prices, CO_2 emission price, and the efficiency of traditional biomass CHP.

1. Sensitivity in biomass price

Using the 2021 Spanish biomass price from Deliverable 3.6 as initial price, the same proportion of price reduction in natural gas between 2021 and 2030 as informed by the Iberian Gas Market [17] was considered. Consequently, biomass prices increase from 2.70 EUR/GJ to 5.02 EUR/GJ.

The increase in biomass price does not reduce the investment in BTC, as shown in Table 22. This is because BTC continues to be the most economical option compared to alternatives. Investments in heat pumps increase by 200 MW.

Table 22: Investments in storage and heat technologies in the Spanish 2030 scenario with higher biomass price

Technology	Investment El. [MW]	Investment Heat [MW]	LCOE [EUR/MWh]	LCOH [EUR/MWh]
Candidate Units				
Batteries	0	-	-	-
Closed Loop PHS (new)	3,396	-	29.5	-
CHP Gas	1,159	1,500	17.2	13.3
CHP Biomass	158	1,500	26.3	2.8
BTC	2,373	1,500	35.4	55.9
Boiler Biomass	-	209	-	3.2
Boiler Coal	-	0	-	-
Boiler Electric	-	1,500	-	0.7
Boiler Gas	-	0	-	-
Boiler H2	-	0	-	-
Boiler Oil	-	0	-	-
Heat Pump	-	1,499	-	4.4

The increase in biomass price slightly reduces the generation in BTC and marginally changes other technologies, as shown in Table 23. Electricity renewable generation does not change, while renewable heat generation slightly changes from biomass to electricity due to increased heat pump heat generation.

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grand agreement N° 101037085.

Table 23 Generation by technologies in the Spanish 2030 scenario with higher biomass price

Technology	Electricity Gen [GWh]	Electricity Cons [GWh]	Curtailment [GWh]	Heat Gen [GWh]	Emissions [MtCO2]
Non-candidate units					
Onshore wind	117,002	-	0	-	-
Offshore wind	9,311	-	1,287	-	-
Solar PV	124,682	-	7,469	-	-
Solar Thermal	5,083	-	-	-	-
Hydropower (no PHS)	13,428	-	351	-	-
Open Loop PHS	11,401	-5,904	-	-	-
Closed Loop PHS	5,398	-7,198	-	-	-
Nuclear	26,035	-	-	-	-
CCGT	4,569	-	-	-	2.285
Electrolyzers	-	-52,000	-	-	-
Electric Vehicles	-	-5,596	-	-	-
Candidate Units					
Batteries	0	0	-	-	-
Closed Loop PHS (new)	4,999	-6,665	-	-	-
CHP Gas	4,605	-	-	5,959	1.566
CHP Biomass	1,234	-	-	11,725	-
BTC	15,035	-	-	9,504	-
Boiler Biomass	-	-	-	253	-
Boiler Coal	-	-	-	0	-
Boiler Electric	-	-4,299	-	3,613	-
Boiler Gas	-	-	-	0	-
Boiler H2	-	-	-	0	-
Boiler Oil	-	-	-	0	-
Heat Pump	-	-2,222	-	6,573	-

	Renewable [%]	Fossil [%]	Electric [%]
Electricity Gen	89.4%	10.6%	-
Heat Gen	57.1%	15.8%	27.1%

The total system cost increases by 8% due to the higher investment and operation costs (Table 24).

Table 24 Spanish system costs results with higher biomass price 2030

Cost Type	[MEUR]
Investment Cost	823
Generation Operation Cost	1,297
Consumption Operation Cost	36
Emission Cost	293
Reliability Cost	0
Total System Cost	2,449

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grand agreement N° 101037085.

2. Sensitivity in CO_2 emission price

The EU ETS CO_2 emission price forecast as informed by ENTSO-E [10] is used, thus increasing the value of this parameter from 76.04 EUR/tonCO_2 to 113 EUR/tonCO_2.

Table 25 shows that due to the increase in CO_2 emission price, investments in closed-loop PHS, biomass boilers, and heat pumps increase.

Table 25: Investments in storage and heat technologies in the Spanish 2030 scenario with higher CO_2 price

Technology	Investment El. [MW]	Investment Heat [MW]	LCOE [EUR/MWh]	LCOH [EUR/MWh]
Candidate Units				
Batteries	0	-	-	-
Closed Loop PHS (new)	4,002	-	31.6	-
CHP Gas	1,159	1,500	18.3	14.1
CHP Biomass	158	1,500	25.5	2.7
BTC	2,373	1,500	35.5	56.2
Boiler Biomass	-	537	-	-
Boiler Coal	-	0	-	-
Boiler Electric	-	1,500	-	-
Boiler Gas	-	0	-	-
Boiler H2	-	0	-	-
Boiler Oil	-	0	-	-
Heat Pump	-	1,499	-	4.6

Renewable curtailment and gas fuelled technologies' generation are reduced, while closed-loop PHS and CHP with biomass generation increase (Table 26). The competition between conventional biomass CHP and BTC depends on the electricity and heat needs together, and BTC has a higher P/Q ratio. In this case, there is not enough room for additional electricity generation. Therefore, the model dispatches more conventional biomass CHP to meet heat demand. Total renewable generation for electricity and heat slightly increase.

Table 26 Generation by technologies in the Spanish 2030 scenario with higher CO_2 price

Technology	Electricity Gen [GWh]	Electricity Cons [GWh]	Curtailment [GWh]	Heat Gen [GWh]	Emissions [MtCO2]
Non-candidate units					
Onshore wind	117,002	-	0	-	-
Offshore wind	9,336	-	1,262	-	-
Solar PV	125,103	-	7,048	-	-
Solar Thermal	5,070	-	-	-	-
Hydropower (no PHS)	13,431	-	348	-	-
Open Loop PHS	11,327	-5,807	-	-	-
Closed Loop PHS	5,144	-6,859	-	-	-
Nuclear	26,035	-	-	-	-
CCGT	4,446	-	-	-	2.223

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Electrolyzers	-	-52,000	-	-	-
Electric Vehicles	-	-5,596	-	-	-
Candidate Units					
Batteries	0	0	-	-	-
Closed Loop PHS (new)	5,569	-7,425	-	-	-
CHP Gas	4,330	-	-	5,603	1.472
CHP Biomass	1,276	-	-	12,124	-
BTC	14,956	-	-	9,454	-
Boiler Biomass	-	-	-	528	-
Boiler Coal	-	-	-	0	-
Boiler Electric	-	-4,313	-	3,624	-
Boiler Gas	-	-	-	0	-
Boiler H2	-	-	-	0	-
Boiler Oil	-	-	-	0	-
Heat Pump	-	-2,127	-	6,293	-

	Renewable [%]	Fossil [%]	Electric [%]
Electricity Gen	89.5%	10.5%	-
Heat Gen	58.8%	14.9%	26.4%

Due to the increase in CO2 prices, the total system cost increases by 6%, mainly due to the increase in emission cost (43%), a slight increase in investment cost, and a small reduction in operation cost due to the reduction in CCGT generation, see table below.

Table 27 Spanish system costs with higher CO_2 price 2030

Cost Type	[MEUR]
Investment Cost	852
Generation Operation Cost	1,103
Consumption Operation Cost	37
Emission Cost	418
Reliability Cost	0
Total System Cost	2,409

3. Sensitivity in Biomass CHP P/Q ratio

The characterization of biomass CHP technology was taken from [12] ("wood-fired industrial CHP") for 2030 main cases. Since the ratio between electric and thermal power (P/Q ratio) is considerably low, it was decided to perform a sensitivity analysis on this parameter. This technology is now modelled with the technical parameters provided for "biogenic gas industrial CHPs", which are the same as those provided for natural gas industrial CHPs. The biomass CHP P/Q ratio then increases from 0.105 MWe/MWth to 0.733 MWe/MWth.

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The increase in biomass CHP P/Q ratio incentivizes the investments in that technology, reducing investments in closed-loop PHS (Table 28).

Table 28: Investments in storage and heat technologies in the Spanish 2030 scenario with higher CHP P/Q ratio for biomass CHP technology

Technology	Investment El. [MW]	Investment Heat [MW]	LCOE [EUR/MWh]	LCOH [EUR/MWh]
Candidate Units				
Batteries	0	-	-	-
Closed Loop PHS (new)	2,354	-	28.2	-
CHP Gas	1,159	1,500	27.2	21.0
CHP Biomass	1,159	1,500	8.2	6.4
BTC	2,373	1,500	38.4	60.8
Boiler Biomass	-	500	-	2.2
Boiler Coal	-	0	-	-
Boiler Electric	-	1,500	-	0.5
Boiler Gas	-	0	-	-
Boiler H2	-	0	-	-
Boiler Oil	-	0	-	-
Heat Pump	-	1,499	-	3.9

Table 29 shows that biomass CHP generation also increases, significantly reducing the generation of CCGT, closed-loop PHS, gas CHP and BTC generation by 8%. This results in a 1% increase of electricity and heat generation from renewables.

Table 29: Generation by technologies in the Spanish 2030 scenario with higher biomass CHP P/Q ratio

Technology	Electricity Gen [GWh]	Electricity Cons [GWh]	Curtailment [GWh]	Heat Gen [GWh]	Emissions [MtCO2]
Non-candidate units					
Onshore wind	117,002	-	0	-	-
Offshore wind	9,019	-	1,579	-	-
Solar PV	122,234	-	9,917	-	-
Solar Thermal	5,021	-	-	-	-
Hydropower (no PHS)	13,359	-	419	-	-
Open Loop PHS	11,371	-5,865	-	-	-
Closed Loop PHS	5,311	-7,081	-	-	-
Nuclear	26,035	-	-	-	-
CCGT	2,599	-	-	-	1.299
Electrolyzers	-	-52,000	-	-	-
Electric Vehicles	-	-5,596	-	-	-
Candidate Units					
Batteries	0	0	-	-	-
Closed Loop PHS (new)	3,299	-4,398	-	-	-
CHP Gas	2,905	-	-	3,760	0.988
CHP Biomass	9,601	-	-	12,425	-
BTC	13,834	-	-	8,745	-

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Boiler Biomass	-	-	-	883	-
Boiler Coal	-	-	-	0	-
Boiler Electric	-	-5,248	-	4,410	-
Boiler Gas	-	-	-	0	-
Boiler H2	-	-	-	0	-
Boiler Oil	-	-	-	0	-
Heat Pump	-	-2,502	-	7,404	-

	Renewable [%]	Fossil [%]	Electric [%]
Electricity Gen	90.5%	9.5%	-
Heat Gen	58.6%	10.0%	31.4%

An increase in biomass CHP P/Q ratio reduces the total system cost by 12% (Table 30), due to less natural gas consumption, more efficient biomass generation, and fewer CO2 emissions.

Table 30 Spanish system costs with higher CHP P/Q price 2030

Cost Type	[MEUR]
Investment Cost	816
Generation Operation Cost	968
Consumption Operation Cost	32
Emission Cost	174
Reliability Cost	0
Total System Cost	1,990

3.5.2 2050 scenarios

1. Sensitivity in biomass price (higher)

Following the same procedure as the sensitivity for the 2030 scenario, the biomass price now increases from 2.15 EUR/GJ to 3.99 EUR/GJ. The increase in biomass price mainly increases investments in heat pumps, electric boilers, and BTC (Table 31).

Table 31: Investments in storage and heat technologies in the Spanish 2050 scenario with higher biomass price

Technology	Investment El. [MW]	Investment Heat [MW]	LCOE [EUR/MWh]	LCOH [EUR/MWh]
Candidate Units				
Batteries (new)	4,000	-	34.1	-
Closed Loop PHS (new)	1,144	-	91.1	-
CHP Biomass	930	1,500	39.1	24.2
BTC	407	231	42.9	75.7
Boiler Biomass	-	1,500	-	14.1

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Boiler Electric	-	2,146	-	0.5
Boiler H2	-	0	-	-
Heat Pump	-	2,998	-	2.3

The increase in biomass price decreases the generation of biomass CHP and boilers while increasing the generation of BTC and electric boilers (Table 32). Heat generation from electrical appliances increases by 1% while decreasing the renewable generation.

Table 32 Generation by technologies in the Spanish 2050 scenario with higher biomass price

Technology	Electricity Gen [GWh]	Electricity Cons [GWh]	Curtailment [GWh]	Heat Gen [GWh]
Non-candidate units				
Onshore wind	266,002	-	0	-
Offshore wind	28,353	-	16,647	-
Solar PV	279,841	-	10,168	-
Solar Thermal	14,938	-	-	-
Hydropower (no PHS)	13,455	-	323	-
Open Loop PHS	9,225	-3,003	-	-
Closed Loop PHS	4,850	-6,466	-	-
CC (biomass and H2)	18,102	-	-	-
Electrolyzers	-	-171,000	-	
Electric Vehicles	-	-68,001	-	
Candidate Units				
Batteries (new)	3,046	-3,229	-	-
Closed Loop PHS (new)	582	-776	-	-
CHP Biomass	3,411	-	-	5,502
BTC	1,238	-	-	701
Boiler Biomass	-	-	-	411
Boiler Electric	-	-7,399	-	6,292
Boiler H2	-	-	-	0
Heat Pump	-	-7,169	-	24,721

	Renewable [%]	Fossil [%]	Electric [%]
Electricity Gen	100.0%	0.0%	-
Heat Gen	17.6%	0.0%	82.4%

ENS [GWh]	HNS [GWh]
0.95	0.00

Total system cost increased by 23% (from 1,224 to 1,510 M€) due to the increase in biomass price, mainly due to operation (biomass fuel) cost, but also due to the increase of investment costs (Table 33).

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Table 33 Spanish system costs result in higher biomass price 2050 (reference in parentheses)

Cost Type	[MEUR]
Investment Cost	410
Generation Operation Cost	1,070
Consumption Operation Cost	21
Emission Cost	0
Reliability Cost	9
Total System Cost	1,510

2. Sensitivity in reduced BTC CAPEX

While the main case for 2050 does not invest in BTC technology, it starts being competitive with a reduction of 10% of CAPEX (from 4933.8 MEUR to 4440.4 MEUR). This investment in BTC reduces investments in closed-loop PHS and heat pumps.

Table 34 Investments in storage and heat technologies in the Spanish 2050 scenario with 10% lower BTC CAPEX

Technology	Investment El. [MW]	Investment Heat [MW]	LCOE [EUR/MWh]	LCOH [EUR/MWh]
Candidate Units				
Batteries (new)	4,000	-	33.5	-
Closed Loop PHS (new)	1,300	-	116.5	-
CHP Biomass	930	1,500	33.3	20.6
BTC	273	155	37.0	65.4
Boiler Biomass	-	1,500	-	8.4
Boiler Electric	-	2,078	-	0.5
Boiler H2	-	0	-	-
Heat Pump	-	2,810	-	2.3

With reduced CAPEX BTC generation replaces electric generation from batteries and closed-loop PHS. Heat generation from biomass and electric boilers and heat pumps are reduced.

Table 35 Generation by technologies in the Spanish 2050 scenario with 10% lower BTC CAPEX

Technology	Electricity Gen [GWh]	Electricity Cons [GWh]	Curtailment [GWh]	Heat Gen [GWh]
Non-candidate units				
Onshore wind	266,002	-	0	-
Offshore wind	28,112	-	16,889	-
Solar PV	278,826	-	11,183	-
Solar Thermal	14,960	-	-	-
Hydropower (no PHS)	13,433	-	345	-
Open Loop PHS	8,689	-2,289	-	-
Closed Loop PHS	4,133	-5,511	-	-

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CC (biomass and H2)	18,481	-	-	-
Electrolyzers	-	-171,000	-	
Electric Vehicles	-	-68,001	-	
Candidate Units				
Batteries (new)	3,100	-3,286	-	-
Closed Loop PHS (new)	479	-639	-	-
CHP Biomass	4,003	-	-	6,456
BTC	867	-	-	490
Boiler Biomass	-	-	-	690
Boiler Electric	-	-7,514	-	6,390
Boiler H2	-	-	-	0
Heat Pump	-	-6,844	-	23,601

	Renewable [%]	Fossil [%]	Electric [%]
Electricity Gen	100.0%	0.0%	-
Heat Gen	20.3%	0.0%	79.7%

ENS [GWh]	HNS [GWh]
0.95	0.00

The system cost is slightly modified with a 10% BTC reduction, reducing investment costs and increasing the operational costs by 8 MEUR.

Table 36 Spanish system costs with 10% lower BTC, 2050

Cost Type	[MEUR]
Investment Cost	394
Generation Operation Cost	802
Consumption Operation Cost	18
Emission Cost	0
Reliability Cost	9
Total System Cost	1,223

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4 Swedish case

The Swedish energy system is partly based on domestic sources of renewable energy such as rivers water, wind and biofuel. In addition, a large proportion of the energy supplied is dependent on imports, such as nuclear fuel for electricity production in nuclear reactors and fossil fuels, such as oil and natural gas for the transport system. Swedish electricity production is based largely on hydropower and nuclear power, but the expansion of wind power is steadily increasing. The production and use of biofuels for electricity and heat production is also increasing.
The final energy usage in Sweden can be divided into three user sectors: **the industry sector, the transport sector, and the residential and service sector.** The residential and service sector mainly use energy from district heating, electricity, oil, and biofuels. In the industrial sector, energy is used mainly to operate processes. This sector primarily uses biofuels and electricity.
Energy use within transportation is mainly based on oil products in the form of petrol, diesel, and aviation fuel. Electricity and biofuels are also a growing source of energy within transportation [18].

4.1 Overview of the Swedish electricity system

The high-voltage (HV) transmission network (please see Figure 10) is the backbone of the Swedish electricity system which together with electricity markets ensures the country's secure electricity supply.

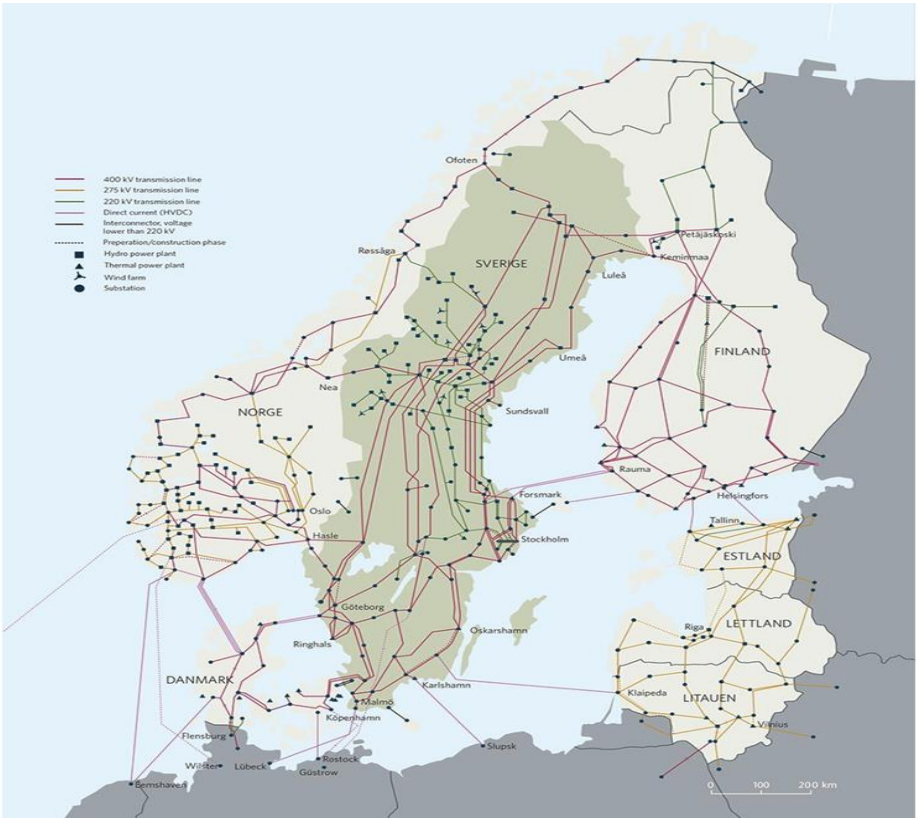

Figure 10: Map of the Nordic and Baltic transmission grid, 2021. Source: Svenska Kraftnät

4.1.1 Electricity production and consumption distribution

Swedish electricity production historically is mainly from hydropower located in the northern part of the country, nuclear power, and thermal power [19]. In contrary, Swedish consumption is located in the southern part of the country; thus, most of the HV transmission capacity runs from north to south

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to transfer the electric power (see Figure 10). Big variations between local production and consumption sometimes lead to transmission bottlenecks. Sweden is divided into four bidding zones to account for these bottlenecks and ensure secure operation of the electricity system (see Figure 11). When the transmission lines are getting congested, electricity market clearing is resulting in different prices for each bidding zone to improve the local balance between supply and demand.

Electricity production per generation source as well as the consumption incl. distribution losses among the bidding zones is set in Table 37Table . According to Table 37, hydropower is located mainly in SE1 and SE2, nuclear power is in SE3, renewable energy sources (mainly solar and wind) are distributed about evenly around the country whereas the other thermal power is concentrated in SE3. The electricity consumption is heavily concentrated in SE3. Moreover, total generation is higher than consumption in SE1 and SE2; thus, SE1 and SE2 are exporting price zones. In contrast, higher consumption than total production makes SE3 and SE4 as importing price zones.

Figure 11: Map of Nordic and Baltic bidding zones, 2022. Source: Svenska kraftnät.

Table 37: Electricity production and consumption in Sweden per price zone, 2021. Source: Svenska kraftnät.

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TWh by electricity region in 2021

	SE1	SE2	SE3	SE4	Total
Production					
Hydroelectric power	22.1	38.8	11.4	1.3	73.6
Nuclear power	0.0	0.0	51.4	0.0	51.4
Solar and wind power	4.6	10.8	8.5	4.2	28.1
Other thermal power	0.2	1.1	5.4	1.6	8.3
Total	26.9	50.7	76.7	7.1	161.4
Usage (incl. grid losses)	10.7	15.4	85.9	23.9	135.9

4.1.2 Transmission network

The main purpose of the transmission network in Sweden is to enable efficient transfer of large amounts of electric power from production in the north to consumers in the south as well as to ensure the exchange of electricity with neighbouring Nordic countries and continental Europe. Currently the transmission capacity from north to south is 3,300 MW between SE1 and SE2, 7,300 MW between SE2 and SE3 and 5,600 MW between SE3 and SE4 [19].

4.2 Overview of the Swedish heat sector

CHP production in Sweden is highly renewable already [20]. Efficiency and decarbonization measures in the DH systems are essential for decreasing its impact on the environment. Through the replacement of fossil fuel-based heating by biobased CHP plants (combined heat and power -CHP) connected to DH systems, Sweden implemented many of the mentioned measures. Consequently, Swedish heating system is almost fossil-free; only 1.5 % of the total fuel used in 2020 in DH systems are fossil-based. Today, only a small share of back-up fuels used at peak demand hours are still fossil-based.

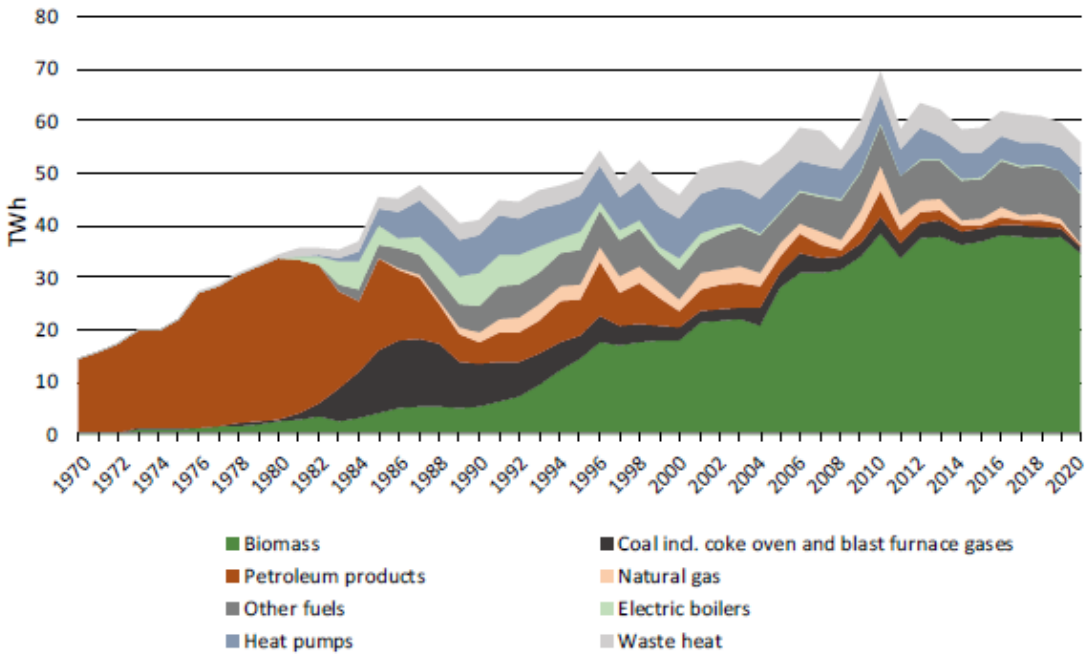

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Figure 12: Input energy used in the production of district heating 1971–2020 [18].

Decarbonization of Swedish DH systems resulted in a major reduction in the effect of the Swedish heating sector on the climate, decreasing greenhouse gas emissions from heating by 90% between 1970 and 2014. In European Union (EU) Sweden has the lowest carbon emissions for DH sector [20]. The input energy used in the production of district heating in Sweden between 1970 and 2020 is shown in Figure 12. In the DH sector in 2020, biomass and waste heat accounted for 62 % and 8 % of the total primary energy respectively. Heat pumps decreased throughout the years to around 8% in 2020 [20]. Since year 2000 the utilization of electric boilers has been continousely decreasing; almost disappearing today due to high electricity prices. Due to the 2002 ban on dumping combustible waste and the 2005 ban against dumping organic waste, the use of waste incineraton increased gradually [18].

Figure 13 shows the development of CHP plant installations in Sweden. Currently 110 biomass and waste-fired CHP plants are connected to 72 of the DH grids [20]. On average the heat and power output of CHP plants are around 65 and 22 MW, respectively. Figure 13 shows that installations of CHP plants took place mostly in the period 2005-2015. In 2021, electricity production from CHP plants was accounting for 9% of the total electricity production in Sweden [21]

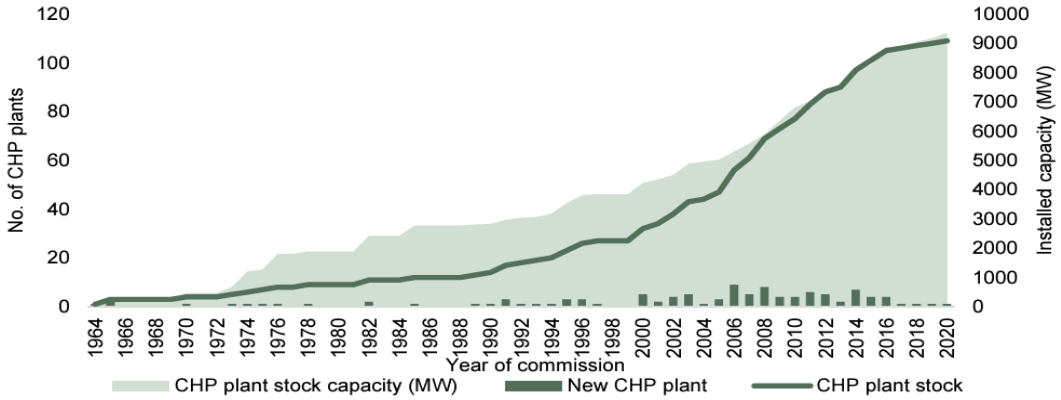

Figure 13: The number of CHP plants commissioned in Sweden between 1964 and 2020, and their installed heat capacity [20].

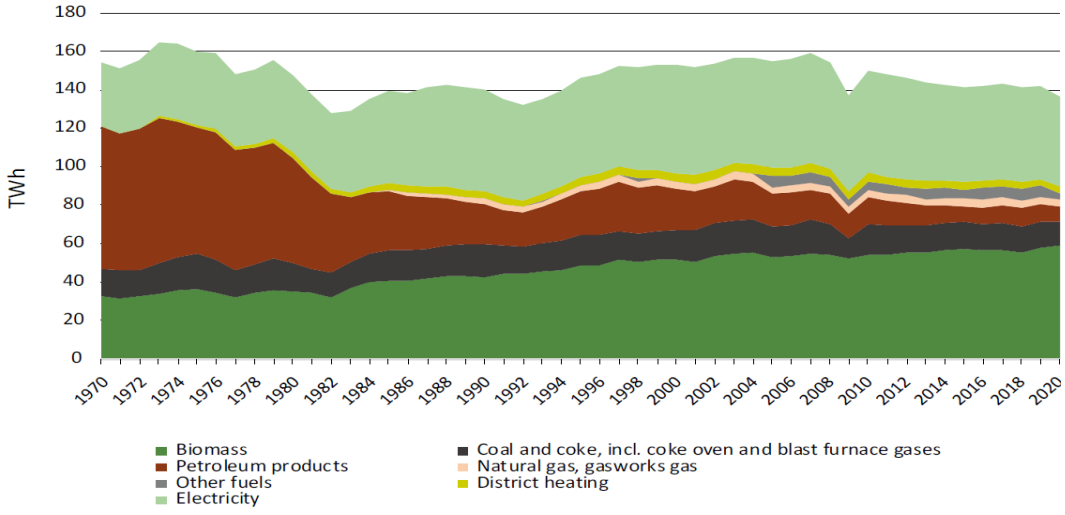

Figure 14: Final energy use in the industrial sector by energy carrier, 1970–2020, TWh [18]

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Figure 14 shows the final energy use in the industrial sector per energy carrier between 1970 and 2020 [18]. In Swedish industry sector, the primary energy carriers are biomass and electricity: about 43% and 34 % of the industry sector' final energy use in 2020 respectively (see Figure 14). Coal and coke accounted for 9 % whereas petroleum products accounted for 6 %. District heating, natural and gasworks gases, and other fuels accounted for the remaining 8 %.

4.3 Specific input data for electric sector for both 2035 and 2045 scenarios

In order to cope with the energy transition and an increased demand, a large expansion of new fossil-free electricity production will be needed in Sweden [21]. This can be done through an expansion of renewable production such as wind and solar power, a new nuclear power plant, which is seen as most likely, or a combination of these options.

Support systems for renewable energy sources combined with decreasing costs enabled a rapid expansion of wind and solar power. In Sweden, above all, onshore wind power has been expanded. However, long permit processes mean that expansion is slower than it might otherwise be, and in recent years a decreasing trend in the pace of expansion and the number of new permits for wind farms has been observed. Although the technical potential for onshore wind power is still very large, it is therefore uncertain to what extent the expansion will continue. At the same time, interest in building solar cells has increased sharply in recent years, both as a result of cost decrease for solar panels and higher electricity prices. Since 2022, Swedish TSO, Svenska kraftnät, has received requests for grid capacity for solar parks of more than 13 GW, several of which are larger than 1 GW. Although solar power can be an important supplement in electricity production, the potential in Sweden is limited due to the low irradiation and therefore production during the winter months. This limitation is reduced however, when industrial consumption increases, which increases the need for electricity even during the summer months [21].
Despite higher costs compared to onshore wind power, offshore wind power can become an important part of the future electricity supply. Advantages such as better wind conditions, the possibility of larger wind farms and turbines as well as a more favourable geographical location for the power system could in the long run justify the higher costs for the power generation [21].
Since 2021 Svenska kraftnät has only received applications for connection corresponding to a total of over 100 GW of offshore wind power. This can be considered a theoretical volume without considering the realistic possibility of obtaining the necessary permits but shows the interest that exists from market players in building offshore wind. To be able to handle the large number of applications and as part of directing the electricity production to areas advantageous for the power system, during the year 2023, Svenska kraftnät has identified locations for the possible connection of up to 14 GW of offshore wind power by 2040. Overall, there is therefore great potential for offshore wind power but also significant uncertainty in how much will ultimately be built.
New nuclear power is also an opportunity to meet the increased demand for fossil-free electricity, and the government adopted in November 2023 a road map for new nuclear power in Sweden which will include credit guarantees for the construction of new nuclear power and simplified permit processes. Nuclear power provides predictable production and the possibility of placing production closer to consumption, which reduces the need to expand the electricity grid. Furthermore, nuclear power contributes to system-stability properties such as short-circuit effect, voltage regulation and rotational energy. The share of nuclear power in the production mix, thus, has a major impact on the need for flexibility. Construction of new reactors has previously been highlighted as economically unprofitable. However, the great need for new electricity production, higher electricity prices as a result of the energy crisis and stronger political support make new nuclear power more likely than before [21].

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When it comes to electricity from CHP plants, there is a reduced heating demand as a result of better insulated buildings and a warmer climate. In LMA 2023 analysis [21], the electricity production from cogeneration in the year 2035, 2045 is therefore assumed to be at similar levels as today.
With its contribution to electricity production and its flexibility, hydropower is a key part of Sweden's power system. It contributes to several aspects needed for a reliable power system such as balancing, frequency stability, voltage stability and power standby capabilities. Hydropower production in LMA2023 is assumed to be at the same level as today in all scenarios.
The greater proportion of weather-dependent non-dispatchable production will increase the need for flexibility in the power system. Hydropower, which has historically accounted for most of the regulation in the Nordics, will not be enough to balance production and consumption. Here, demand response enabled by other types of storage, such as batteries and hydrogen storage, will play a major role in balancing the power system. Even small-scale consumption flexibility from e.g. EV charging has the potential to provide flexibility.
Overall, Svenska kraftnät sees a large increase in electricity consumption as a result of the electrification of the energy system. However, there are significant uncertainties in how large this increase in consumption will be linked to the use of electricity in the fossil-free steel industry. In addition, there are uncertainties regarding the expansion of future electricity production, connected not only with profitability aspects but also legal aspects, such as permit processes for new electricity production, and technical aspects regarding e.g. lifetime extension of nuclear power plants. Depending on generation and consumption, the availability and need for flexibility helping to balance the power system will be affected. The scenarios in LMA are therefore differentiated based on electricity consumption, production mix, the flexibility that is assumed to be available, and the degree of expansion of a hydrogen infrastructure in Sweden and Europe.

Svenska kraftnät has developed four scenarios for long-term market analysis 2023 (LMA): “Elektrifiering planerbart-EP” (plannable electrification), “Elektrifiering förnybart-EF” (renewable electrification), “Färdplaner mixat-FM” (mixed planned) and “Småskaligt förnybart-SF” (small scale renewables). The biggest difference between the scenarios lies in the level of electricity consumption assumed and in what proportion of production comes from nuclear power and renewable production. **Please note that in this work we only focus on EP scenario due to extreme time constraint.**

4.3.1 Generation

Figure 15 shows the current generation installed capacity in Sweden [18]. More than 50% of the generation installed capacity consists of hydropower and nuclear power; 16 GW and 8 GW respectively. Another dominant generation source is wind power with installed capacity of 12.5GW. Other sources are thermal power, CHPs, industrial CHPs, gas turbines and solar. Please note that current installed capacity of all thermal units, including thermal power, CHPs and industrial CHPs is about 4.5 GW.

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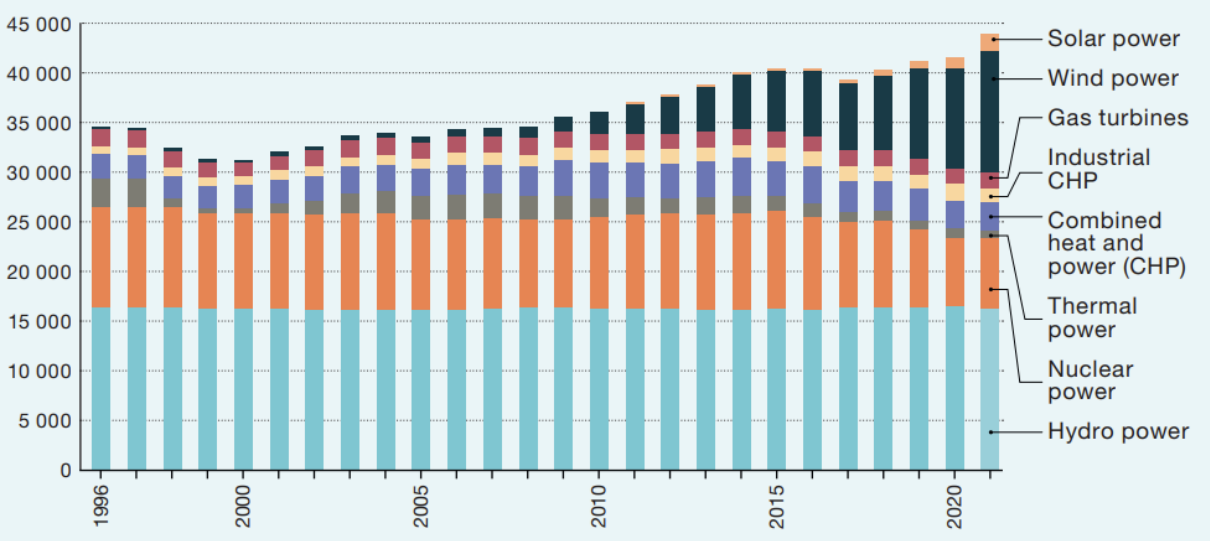
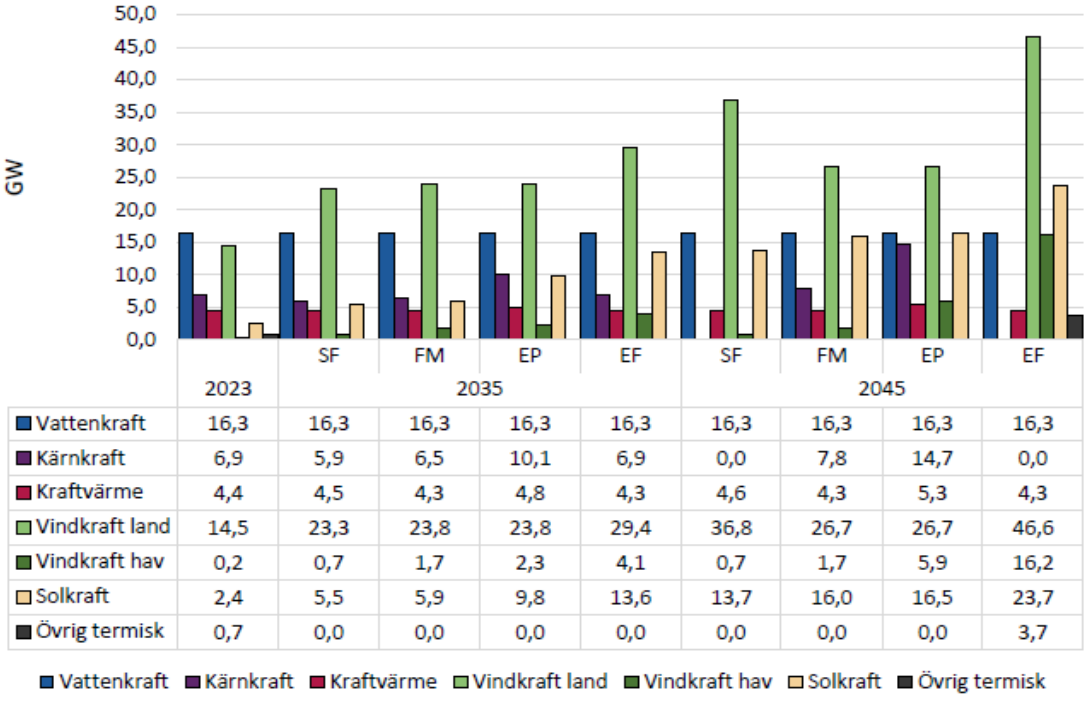


Figure 15: Installed electricity generation capacity by type of power 1996–2021, MW[18].

Installed/planned generation capacity in Sweden for different scenarios and for reference years 2035 and 2045 are summarised in Figure 16 [21].



	2023	2035 SF	2035 FM	2035 EP	2035 EF	2045 SF	2045 FM	2045 EP	2045 EF
Vattenkraft	16,3	16,3	16,3	16,3	16,3	16,3	16,3	16,3	16,3
Kärnkraft	6,9	5,9	6,5	10,1	6,9	0,0	7,8	14,7	0,0
Kraftvärme	4,4	4,5	4,3	4,8	4,3	4,6	4,3	5,3	4,3
Vindkraft land	14,5	23,3	23,8	23,8	29,4	36,8	26,7	26,7	46,6
Vindkraft hav	0,2	0,7	1,7	2,3	4,1	0,7	1,7	5,9	16,2
Solkraft	2,4	5,5	5,9	9,8	13,6	13,7	16,0	16,5	23,7
Övrig termisk	0,7	0,0	0,0	0,0	0,0	0,0	0,0	0,0	3,7

Figure 16: Installed production capacity in Sweden for different scenarios [21]. Vattenkraft-hydropower, Kärnkraft- nuclear power, Kraftvärme-CHP, Vindkraft land-onshore wind, Vindkraft hav-offshore wind, Solkraft-solar power, Övrig termisk-other thermal.

Figure 16 shows that huge increase is planned in onshore wind and solar power in all scenarios. It is assumed to increase nuclear power in EP scenario (about 40 % in 2035 and double the capacity by 2045), whereas gradual increase in offshore wind is assumed in both EP and EF scenarios. Onshore, offshore wind and solar generation time series for every price zone have been generated using the Renewables.ninja tool [22].

DSR

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Demand-side Response (DSR) is also represented within the modelling as a storage unit, with generation able to be used at another time within the modelling. It is assumed 10% and 15% DSR available for 2035 and 2045 scenarios respectively.

Interconnectors are set to be fully dispatchable within the modelling, as a detailed model of availability and prices of interconnected regions for future scenarios is out of scope for this work. Generation from interconnectors is thus set as the most expensive generator within the models, at 125 Euro/MWh, as it is only required at times of particularly high demand and low supply, and as such it is expected that the marginal price of imports will be high at these times.

4.3.2 Transmission capacity

The starting point for the transmission capacity assumed in the scenarios is today's transmission capacity presented in 4.1.2, and is the same for all scenarios. Table 38 shows the in transmission capacity in the Nordic countries and within Sweden in the next 20 years. For Sweden, the so called "NordSyd" (North-South) package will gradually increase the transmission capacity SE2-SE3 to 10.5 GW in 2045. At the same time, the transmission capacity between SE1 and Finland will increase to 2 GW with the Aurora Line in 2025. The Hansa Power Bridge is assumed to be commissioned in 2029 and will then increase the transmission capacity to Germany by 700 MW. The other Nordic countries are also increasing the transmission capacity to the rest of Europe until 2050.

Table 38: Changes in transmission capacity in the Swedish electricity price areas and in the Nordic region.

Year	Line	Change (MW)	Total (MW)	Information/Name
2024	DK1↔UK	+1400	1400	Viking line
2025	SE1→FI FI→SE1	+800 +900	2000 2000	Aurora line (Messaure – Keminmaa)
	DK1↔DE	+1000	3500	Stage 2 Jylland-Germany
2028	SE2↔SE3	+800	8100	Reinforcement line 2
2029	SE4↔DE	+700	1315	Hansa Power Bridge
2030	DK2→DE DE→DK2	+1000 +1000	1585 1600	Connection via Bornholm Energy Island
2032	DK1↔BE	+1400	1400	TritonLink
2034	SE2↔SE3	+1500	9600	Reinforcement line 2
2035	FI↔EE	+684	1700	Estlink 3
	NO2↔UK	+1400	2849	NorthConnect Link
2040	SE2↔SE3	+900	10500	Reinforcement line 2

The transmission capacities modelled in this work for the reference year 2035 and 2045 are extracted from section Transmission network 4.1.2 and Table Table 37 and are summarised in Table 39.

Table 39: Transmission capacities between price areas in Sweden and with neighbouring countries.

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Transmission capacity (MW)	Others-SE1	SE1-SE2	Others-SE2	SE2-SE3	Others-SE3	SE3-SE4	Others-SE4
Current	2700	3300	850	7300	4160	6800	3700
2035	3500	3300	850	9600	4160	6800	4400
2045	3500	3300	1250	10500	4160	6800	4400

4.3.3 Demand

This section describes assumptions for the forecasting of electricity consumption in Sweden until 2050. The consumption estimation in Sweden is mainly based on the connection requests for increased power output received by Svenska kraftnät, but also on external forecasts from industry organizations and other authorities.
Figure 17 shows the electricity consumption in Sweden for the scenarios from 2025 until 2050. The electricity consumption in the EP and EF scenarios is the same and increases to 365 TWh in 2050 and exceeds 200 TWh already in 2030. The largest increase in consumption in the EP and EF scenarios is found in the industry sector and in electricity consumption for hydrogen production, transport, and establishment of data centers, while general consumption in households and services is relatively unchanged.

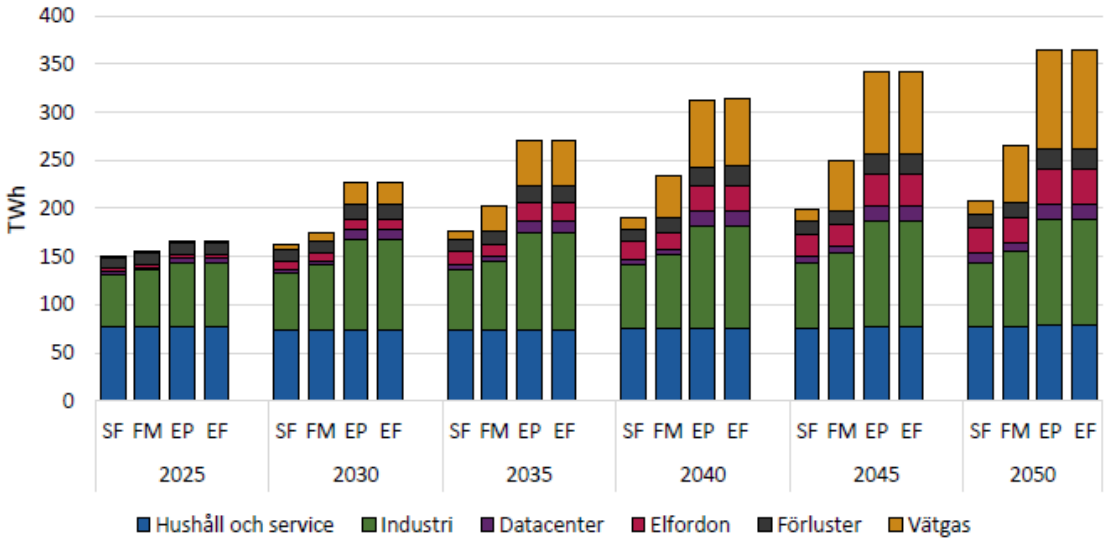

Figure 17: Electricity consumption in Sweden in all scenarios. Hushåll and service-household and service, Industri-Industry, Datacenter- data center, Elfordon-EVs, Förluster-losses, Vätgas-hydrogen.

Hourly demand data that is needed in the model work (for EP scenario only) and for reference year 2035 and 2045 is received from Svenska Kraftnät.

Table 40 shows the electricity consumption for 2050 divided into sub-categories within the various sectors. The largest increase within a single category is for the steel industry, where the total electricity consumption (including the use of electricity for hydrogen production) is approximately 100 TWh in 2050 in the EF and EP scenarios. Other categories where consumption is increasing are in the chemical industry, in the concrete and cement industry, and for the establishment of battery factories and data centers. In addition, there is the category “Other new electricity use”, which contains various new electricity-intensive industries, e.g. production of hydrogen for synthetic fuels and so on.

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Table 40: Electricity consumption per sector in 2025 (the FM scenario) and in 2050 (all scenarios). For consumption in industry, the increase is shown in different sectors, while the existing consumption is in the category of existing industry.

Sector	Category (TWh)	FM 2025	SF 2050	FM 2050	EF/EP 2050
Household and service	Housing & service	70,3	67,9	67,9	69,3
	District heating	4,2	4,2	4,2	4,2
	Railway	2,9	4,7	4,7	4,7
Industry	Existing industry	47,8	48,9	48,9	48,9
	Battery factories	4,4	5,5	8,9	9,1
	Refineries	1	2,6	2,6	3,1
	Fossil-free steel	4	21,3	70	98,8
	Chemical industry	0	0,9	3,7	22,3
	Concrete and cement	0,1	1,2	1,2	3
	Other new electricity use	2,3	1,5	2,3	27,4
Data center	Data center	2,5	9,7	9,7	16,9
EVs	Light-duty traffic	3,3	17,3	17,3	21,2
	Heavy-duty traffic	0,5	8,2	8,2	14,9
Network losses	Regional	7,3	9,1	9,4	13,2
	Local	4,5	5,6	5,7	8,1

4.3.4 Fuel prices

The fuel prices considered in this work are from [21] and shown in Table 41.

Table 41: Fuel prices.

	FM			SF, EP, EF		
EUR/MWh	**2025**	**2030**	**2040**	**2030**	**2040**	**2050**
CO_2 (EUR/ton)	110,0	70,0	90,0	78,0	123,0	168,0
Coal	13,4	8,9	8,7	7,1	6,9	6,7
Light oil	46,3	49,6	55,5	36,3	34,6	32,8
Natural gas	48,8	22,4	24,8	14,5	14,7	14,7
Biogas	86,0	74,7	61,0	74,7	61,0	50,3
Hydrogen import	72,9	72,9	57,9	74,3	57,9	45,1
Nuclear power	1,7	1,7	1,7	1,7	1,7	1,7
Oil shale	5,6	6,7	9,8	6,7	9,8	14,1
Lignite	6,5	6,5	6,5	6,5	6,5	6,5
Biomass	31,9	31,9	31,9	31,9	31,9	31,9
Peat	17,1	17,1	17,1	17,1	17,1	17,1

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It is assumed that the fuel prices in 2035 and 2045 will be the same as 2030 and 2040 respectively.

4.4 Specific input data for the heat sector for both 2035 and 2045 scenarios

4.4.1 Generation

Typical heat generating technologies are boilers, heat pumps and CHP units. In Sweden, the use of electric boilers nearly vanished since 2000 due to increasing electricity prices [18]. Figure 12 shows that in year 2020 heat pump production was about 5 TWh in district heating system. To derive heat pump installed capacities per price zone we used the information in Figure 12 and thermal power distribution among price zones stated in Table 37. The installed capacity for CHP plants is derived using the information stated in section 4.2 ("110 CHP plants connected to DH grid having on average 65 MW_{th} and 22MW_e thermal and electric capacity respectively"). Then, in the similar way, the total installed capacity of CHP units is distributed among the price zones using proportions presented in Table 37. Please note that the values are consistent with the information provided in Figure 15.

The installed capacity of **industrial** CHP units today is about 1.5 GW_e according to Figure 15. Thermal capacity can be derived using typical heat-power ratios of CHP units. Then, using Table distribution, in the same manner, the industrial CHP units can be distributed among four existing price zones in Sweden.
Heat Pumps installed capacities in all sectors is about 20 TWh total as it is shown in Figure 18.

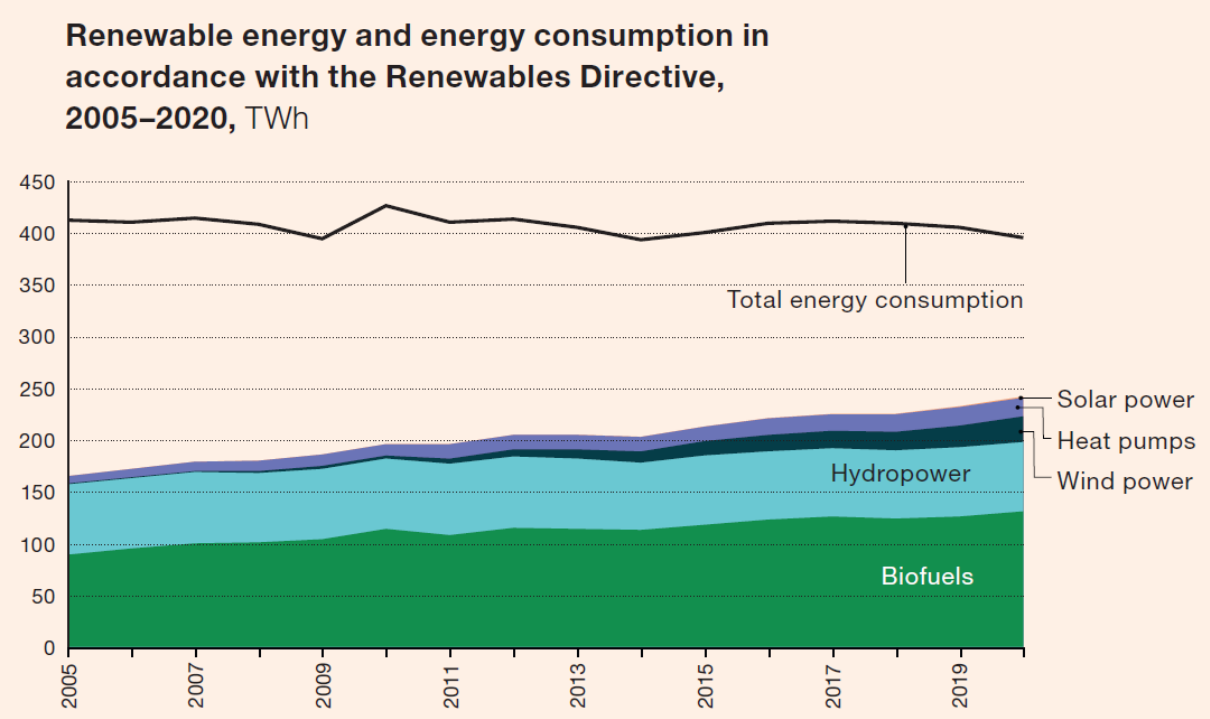

Figure 18: Renewable energy and energy consumption in accordance with the Renewables Directive, TWh. Sources: The Swedish Energy Agency and Eurostat [18].

4.4.2 Demand

Heat demand in Sweden consists of heat demand in DH (residential sector and non-residential sector) and in industry. Figure 19 presents energy carriers per industry type in Sweden for year 2020. The figure shows that heat demand is not dominant in any industry. However, according to long term

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market analysis [21], the steel industry will increase 25 times and chemical industry by 22 times by 2050 (please see Table). Furthermore, streel industry is and will be mainly located in northern part of Sweden close to the mines. Thus, yearly heat demand from industry sector is derived from Table 40 and Figure 19 and it is assumed equally distributed in SE1 and SE2 prise zones.

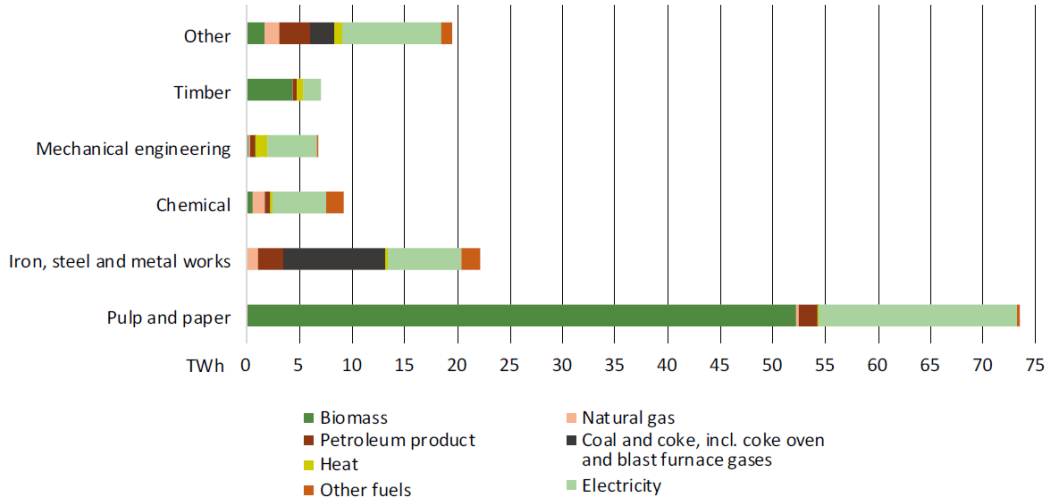

Figure 19: Final energy use of the industrial sector by industry category and energy carrier in 2020, TWh [18]

Reference [23] presents in detail heat demand distribution in DH system in Sweden for years 2015-2022. The heat demand in residential sector (one- or two- family dwellings and multi-family dwellings) in 2022 has been about 30,000 GWh and in non-residential sector (manufacturing and mining, public administration, other services like food, wholesale, and retail trade and so on) about 19,500 GWh , respectively. Figure 20 shows that, DH heat demand in residential sector is going to decrease by 2050 from about 30,000GWh to 23,000 GWh. This is due to climate change and increased energy efficiencies in the buildings.

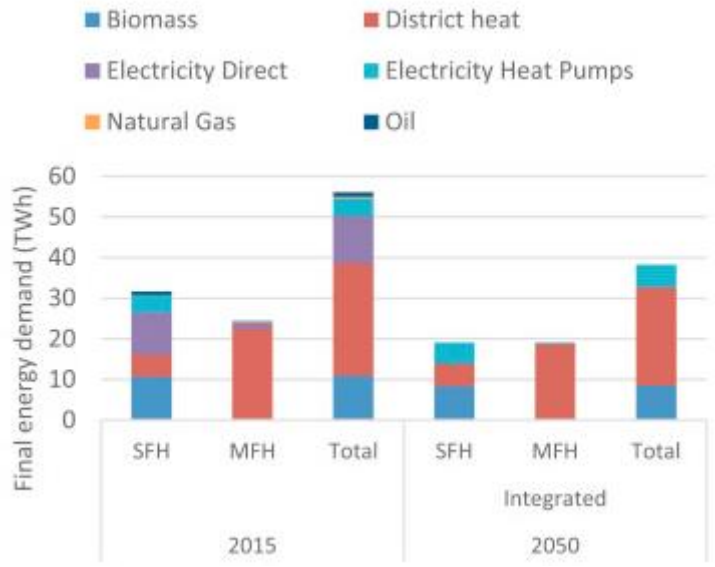

Figure 20: Total energy demand in Single-Family Homes (SFH), Multi-family Homes (MFH) and total residential sector [24]

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We assumed non-residential sector (manufacturing and mining, public administration, snowmelt system, other services like food, wholesale, and retail trade and so on) in Sweden will increase by 10% and 15% in 2035 and 2045 respectively proportional to the population growth. Table Table 37 is used to distribute residential and non-residential district heating heat demand among price zones in Sweden.
Finally, the hourly heat demand for each price zone is derived from Tekniska Verken AB (TvAB) heat demand hourly dynamics for the years 2017-2022.

4.5 2035 scenario

The 2035 base case scenario for Sweden is created based on the information provided in the previous sections and some assumptions. First a benchmark case is created where new BTC CHP technology is not available for investment among other technologies meeting both heat and power demand for the reference year 2035. We name it '2035 w/o BTC'. Then another case is constructed where new BTC CHP technology is available among other technologies for investment decisions to meet the system heat and power demand. We name this case as '2035 with BTC'. Please notice that the base case scenario consists of '2035 w/o BTC' and '2035 with BTC' pairs. Furthermore, Figure 13 shows that most CHPs in Sweden has been installed before 2015. Thus, we assume that 50 % of installed heat generation technologies will be decommissioned by 2035. Another important insight from Figure 12 and Figure 14 is that 40 TWh energy used in the production of district heating and around 50 TWh energy used in industrial sector were sourced from biomass in 2020. We assume that biomass availability is nearly the same in Sweden in 2035 scenario. We assumed the cost of having 1 MW not served energy is equal to 10,000 Euro. The existing installed capacity per technology and potential for capacity investment to meet both heat and power demand in 2035 for both '2035 w/o BTC' and '2035 with BTC' scenarios are summarised in Table 42 and Table 43 respectively.

Table 42: The existing installed capacity per technology and capacity potential for investment in '2035 w/o BTC' scenario.

Technology (MW)	SE1	SE2	SE3	SE4
Hydro	4900	8600	2500	300
Nuclear	0	0	6900	0
Nuclear_new	0	0	3200	0
Solar	1600	3770	2960	1465
Wind onshore	3900	9150	7200	3560
Wind offshore	380	880	700	340
CHP_Biomass	120	665	3250	965
CHP_Waste	20	106	520	155
CHP_Biomass_new	5873	5873	5873	5873
Heat pump	150	150	450	250
Heat pump_new	300	300	1500	600
Heat boiler	0	50	50	0
DSR	822	412	1994	594

Table 43: The existing installed capacity per technology and capacity potential for investment in '2035 with BTC' case scenario.

Technology	SE1	SE2	SE3	SE4
Hydro	4900	8600	2500	300
Nuclear	0	0	6900	0
Nuclear_new	0	0	3200	0

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Solar	1600	3770	2960	1465
Wind onshore	3900	9150	7200	3560
Wind offshore	380	880	700	340
CHP_Biomass	120	665	3250	965
CHP_Waste	20	106	520	155
CHP_Biomass_new	2000	2000	2000	2000
BTC	3873	3873	3873	3873
Heat pump	150	150	450	250
Heat pump_new	300	300	1500	600
Heat boiler	0	50	50	0
DSR	822	412	1994	594

Table 44 The CAPEX values were estimated based on references [21]. Table 44 provides these values used in the 2035 base case scenario in both with and without BTC cases.

Table 44: CAPEX assumptions, EUR/MW [12], [21]

Technology	CAPEX (MEUR/MW)
Nuclear	4.5
CHP_Biomass	2.94
BTC	3.2
Heat_pump	0.27

The Swedish 2035 cases are simulated using open source openTEPES economic investment and dispatch model, described in detail in Annex 1, to satisfy the system electric and heat demand with the least total system cost possible.

4.6 2045 scenario

In the similar way, a 2045 base case scenario for Sweden is created based on the information provided in the previous sections and the following assumptions. Again, baseline scenario pair '2045 w/o BTC' and '2045 with BTC' is created for the reference year of 2045. We assumed that all existing CHP units in Sweden will be decommissioned by the reference year 2045; thus, all CHPs should be invested. In addition, we assumed the biomass availability will be the same as in 2035 case. The cost of having 1 MW not served energy is equal to 10,000 Euro.
The existing installed capacity per technology and potential for capacity investment to meet both heat and power demand in 2045 for both '2045 w/o BTC' and '2045 with BTC' scenarios are summarised in Table 45 and Table 46 respectively.

Table 45: The existing installed capacity per technology and capacity potential for investment in '2045 w/o BTC'.

Technology (MW)	SE1	SE2	SE3	SE4
Hydro	4900	8600	2500	300
Nuclear			6900	
Nuclear_new			7800	
Solar	2700	6341	4991	2475
Wind onshore	4371	10261	8077	4005
Wind offshore	966	2267	1785	885
CHP_Waste	20	106	520	155
CHP_Waste_new	60	60	100	100
CHP_Biomass_new	14245	4748	4748	4748

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Heat pump_new	450	450	2100	1100
DSR	2574	755	3199	997

Table 46: The existing installed capacity per technology and capacity potential for investment in '2045 with BTC' case.

Technology (MW)	SE1	SE2	SE3	SE4
Hydro	4900	8600	2500	300
Nuclear			6900	
Nuclear_new			7800	
Solar	2700	6341	4991	2475
Wind onshore	4371	10261	8077	4005
Wind offshore	966	2267	1785	885
CHP_Waste	20	106	520	155
CHP_Waste_new	60	60	100	100
CHP_Biomass_new	3250	3250	3250	3250
BTC	8144	2443	2443	2443
Heat pump_new	450	450	2100	1100
DSR	2574	755	3199	997

Table 47 provides CAPEX values used in the 2045 cases with and without BTC.

Table 47: CAPEX values used for the reference year 2045 [21].

Technology	CAPEX (MEUR/MW)
Nuclear	4.5
CHP_Biomass	2.94
BTC	3.2
Heat_pump	0.27
CHP_Waste	8

In the same way, the Swedish 2045 cases are simulated using open source openTEPES economic investment and dispatch model, described in detail in Annex 1, to satisfy the system electric and heat demand with the least cost possible.

4.7 Results and discussions-Sweden 2035

This section summarises the Swedish energy system simulation results for the reference years 2035. The heat and electricity generation per technology and per price zone are summarized in Table 48 together with few other key parameters. The table also shows the invested electricity and heat volumes in each technology as well as dispatched volumes from invested technologies. According to '2035 with BTC' results the nuclear power is not getting invested as the technology has the highest CAPEX value. The existing heat and electricity demand are met by investing mostly in heat pumps, CHP_biomass and BTC. Heat-pumps are getting invested by 100%. CHP_biomass units are fully invested in SE3 and SE4, and close to 100% in SE1 and SE2. BTC is getting invested and dispatched in SE3 and SE4 where the electricity and heat demand are higher for 2035 reference year. Table 48 also presents LCOE and LCOH values for all invested units. We can see that for the reference year 2035 LCOE and LCOH values are very low for both heat-pumps and CHP_biomass technology compared that of BTC.

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Table 48: Heat and electricity generation, average prices, curtailment and emission values per technology for 2035 with BTC.

	Electricity Generation				Heat Generation			
Existing Technology (GWh)	**SE1**	**SE2**	**SE3**	**SE4**	**SE1**	**SE2**	**SE3**	**SE4**
Hydro	24003.8	42129.4	12247	1470	.	.	.	.
Nuclear	.	.	42556.6	.	.	.	.	.
Solar	1952.6	4585.8	3936.6	2135	.	.	.	.
Wind Onshore	9624	23774	19528	15660	.	.	.	.
Wind offshore	1478	3931	3566	1656	.	.	.	.
CHP_biomass	165,6	795	921	515	497	2386	2764	1546
CHP_waste	42	232	1136	337	125	697	3407	1012
Heat boiler	.	.	.	.	.	1	1	.
Heat pump	.	.	.	.	1260	1260	3891	2164
DSR	83	17	309	27	.	.	.	.
Candidate for investment								
Nuclear_new	.	.	0.0	.	.	.	.	.
CHP_biomass_new	654	1278	1787	1416	1961	3834	5362	4249
BTC	0.0	0.0	21.4	11.4	0.0	0.0	13.4	7.2
Heat_pump_new	.	.	.	.	2000	2594	10918	5168
Economics								
SRMC (EUR/MWh)	13.0	15.0	25.4	25.4				

	RES (%)	Fossil (%)	Electric (%)
Electricity Generation	99	0.78	0.194
Heat Generation	39.535	9.16	51.3

Technology (GWh)	El consumption (GWh)	Curtailment (GWh)	Emission (MtCO2)
Hydro	0	.	.
Nuclear	0	.	.
Solar	0	15	.
Wind Onshore	0	9.6	.
Wind offshore	0	10.8	.
CHP_biomass	0	.	.
CHP_waste	0	.	1,86
Heat boiler	0	.	0,00054
Heat pump	9783	.	.
DSR	436	.	.

Candidate for investment	Investment electricity (MW)	Investment Heat (MW)	LCOE (EUR/MWH)	LCOH (EUR/MWH)
Nuclear_new	0	.	0	0
CHP_biomass_new	1917.3	5751.9	76.82	25.6
BTC	350.85	219	2392.76	3785

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Heat_pump_new	.	900	.	2.5

Similarly, *Table 49* presents the results of the reference year 2035, '2035 w/o BTC' case. In this case BTC technology is not available to invest. Thus, the model invests mostly in heat-pumps and CHP_biomass to meet the heat and electricity demand. Again, no investment is made in nuclear technology. In this case, the LCOE and LCOH values of the invested technologies are even lower as they are getting more frequently dispatched in the case of '2035 w/o BTC' compared that of '2035 with BTC' case.

Table 49 Heat and electricity generation by technology for 2035 without BTC.

	Electricity Generation				Heat Generation			
Existing Technology (GWh)	**SE1**	**SE2**	**SE3**	**SE4**	**SE1**	**SE2**	**SE3**	**SE4**
Hydro	24003.8	42129.4	12247	1470	.	.	.	.
Nuclear			42598		.	.	.	.
Solar	1953	4589.4	3936	2130	.	.	.	.
Wind Onshore	9624	23776	19528	15658	.	.	.	.
Wind offshore	1478	3930	3565.8	1655.4	.	.	.	.
CHP_biomass	91.8	882	313.8	80	275.6	2646	941.6	240
CHP_waste	42	232.4	1135.6	337.2	125.8	697	3407	1012
Heat boiler	.	.	.			1.2	1.2	
Heat pump	.	.	.		1052	1306	3365.4	1865
DSR	83	17.6	296	26	.	.	.	.
Candidate for investment								
Nuclear_new	.	.	0	.	.	.	.	.
CHP_biomass_new	0	0	2516	3644	0	0	7548	10932
BTC	.	.	.	.				
Heat_pump_new	.	.	.	.	2372	2530	12604	4288
Economics								
SRMC (EUR/MWh)	13.3	13.7	14	14				

	RES (%)	Fossil (%)	Electric (%)
Electricity Generation	99	0.78	0.189
Heat Generation	39.477	9.16	51.36

Existing Technology (GWh)	El consumption (GWh)	Curtailment (GWh)	Emission (MtCO2)
Hydro	0	.	.
Nuclear	0	.	.
Solar	0	14	.
Wind Onshore	0	10	.
Wind offshore	0	12	.
CHP_biomass	0	.	.

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CHP_waste	0	.	1.86
Heat boiler	0	.	0.00064
Heat pump	9794.4	.	.
DSR	423.6	.	.

Candidate for investment	Investment electricity (MW)	Investment Heat (MW	LCOE (EUR/MWH)	LCOH (EUR/MWH)
Nuclear_new	0	.	.	.
CHP_biomass_new	1798	5394	60	20
BTC	.	.	.	.
Heat_pump_new	.	900	.	2.38

Table 50 provides the summary of cost components together with 'heat not served' and 'electricity not served' for both '2035 w/o BTC' and '2035 with BTC' cases. We can note that the heat demand is 100% met in both cases, however, there is small volume of electricity not served in both with and without BTC cases; 0.13 and 6.63 GWh respectively which results in reliability cost of 1.3 and 66.3 MEUR accordingly. This means that BTC integration of Swedish energy system in 2035 decreases the ENS and reliability cost with 98%. Moreover, BTC integration in the Swedish 2035 system results in lower emission volumes, thus lower emission cost, see Table 5051. However, the investment cost is higher for the case of '2035 with BTC' than that of '2035 w/o BTC' resulting about 5% higher total system cost for '2035 with BTC' case.

Table 50: Swedish system costs and balance with/without BTC 2035.

Cost Type	2035 with BTC (MEUR)	2035 w/o BTC (MEUR)
Total system cost	**1086.6**	**1047**
Investment cost	525	422
Operational cost	374	372.8
Consumption operation cost	0.1	0.1
Emission cost	186	186
Reliability Cost	1.3	66.3

System balance		
Heat Not served (GWh)	0.0	0.0
Electricity not served (GWh)	0.13	6.63

4.8 Sensitivity analyses-Sweden 2035

This section performs sensitivity analysis for Swedish energy system in the reference year 2035. Sensitivity analyses are conducted to study the system behaviour while decreasing BTC CAPEX by 25% and biomass prices by 40 %.
Table 51 sets out invested volumes per technology in all three cases. The same information is depicted in Figure 21. We can't observe any sharp difference in volume invested in BTC even in the case when BTC CAPEX is decreased by 25%.

Table 51: Invested volume per technology (MW).

	2035 with BTC	25% lower BTC CAPEX	40% lower biomass price

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Technology	Investment electricity	Investment heat	Investment electricity	Investment heat	Investment electricity	Investment heat
BTC	350.85	219	367.12	229.5	350.85	219
CHP_biomass _new	1917.3	5751.9	1879	5637	1917.3	5751.9
Heat_pump _new	.	900	.	900	.	900
Nuclear_new	.	.	.	.	.	.

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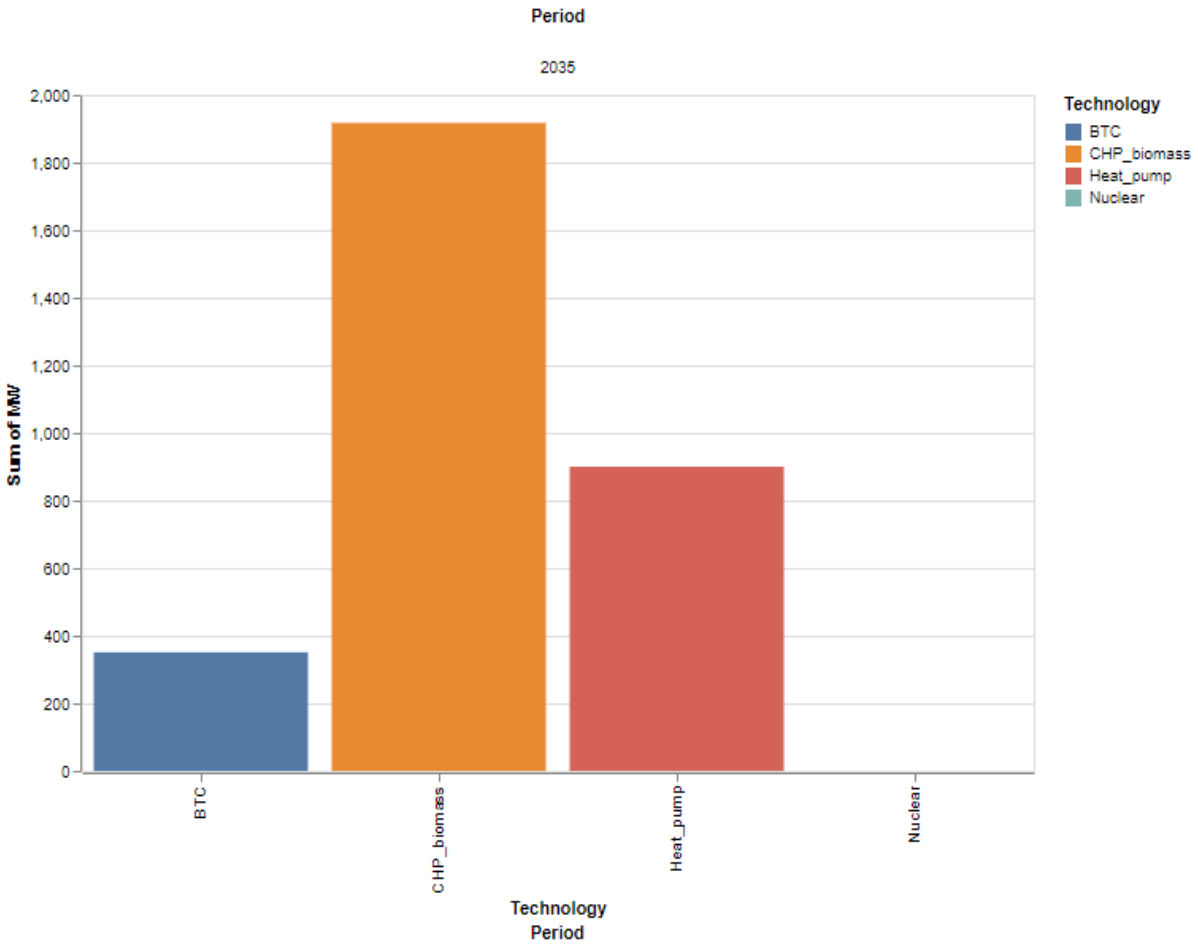

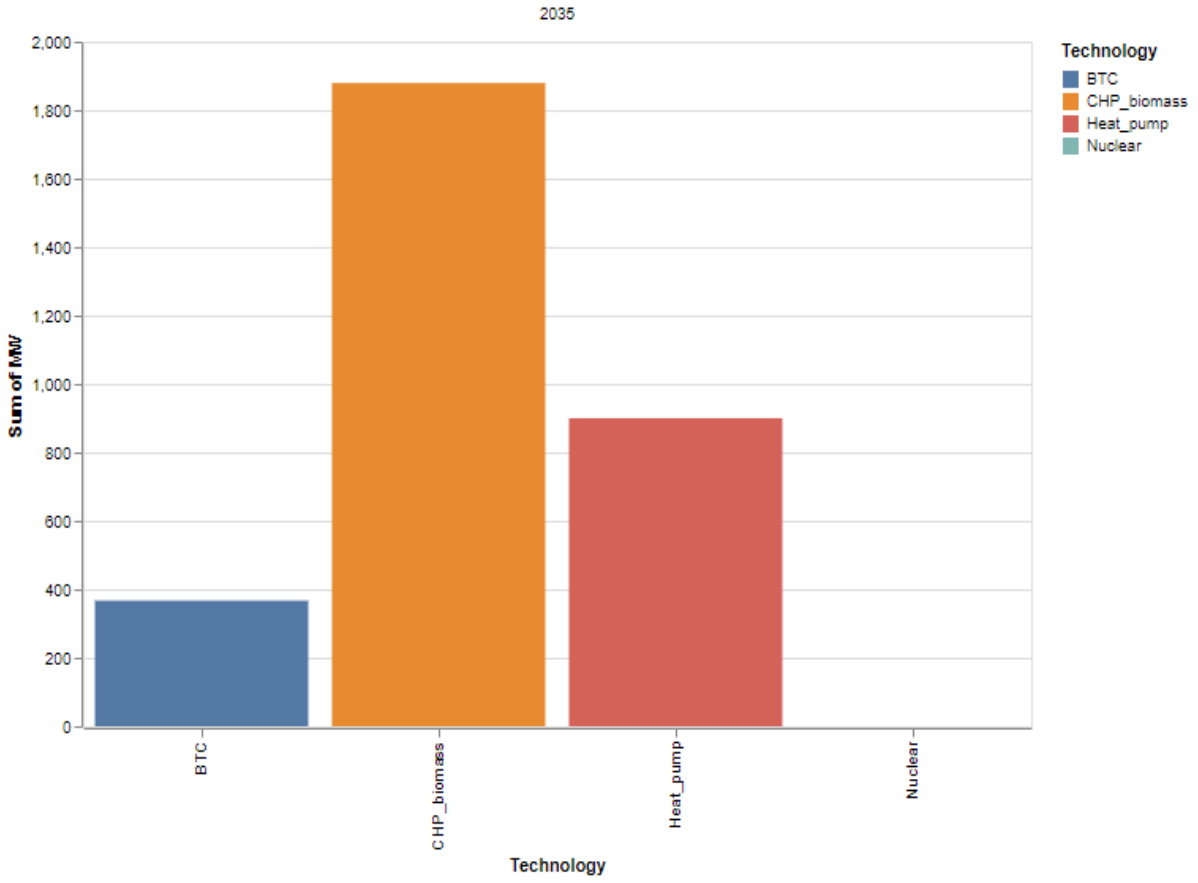

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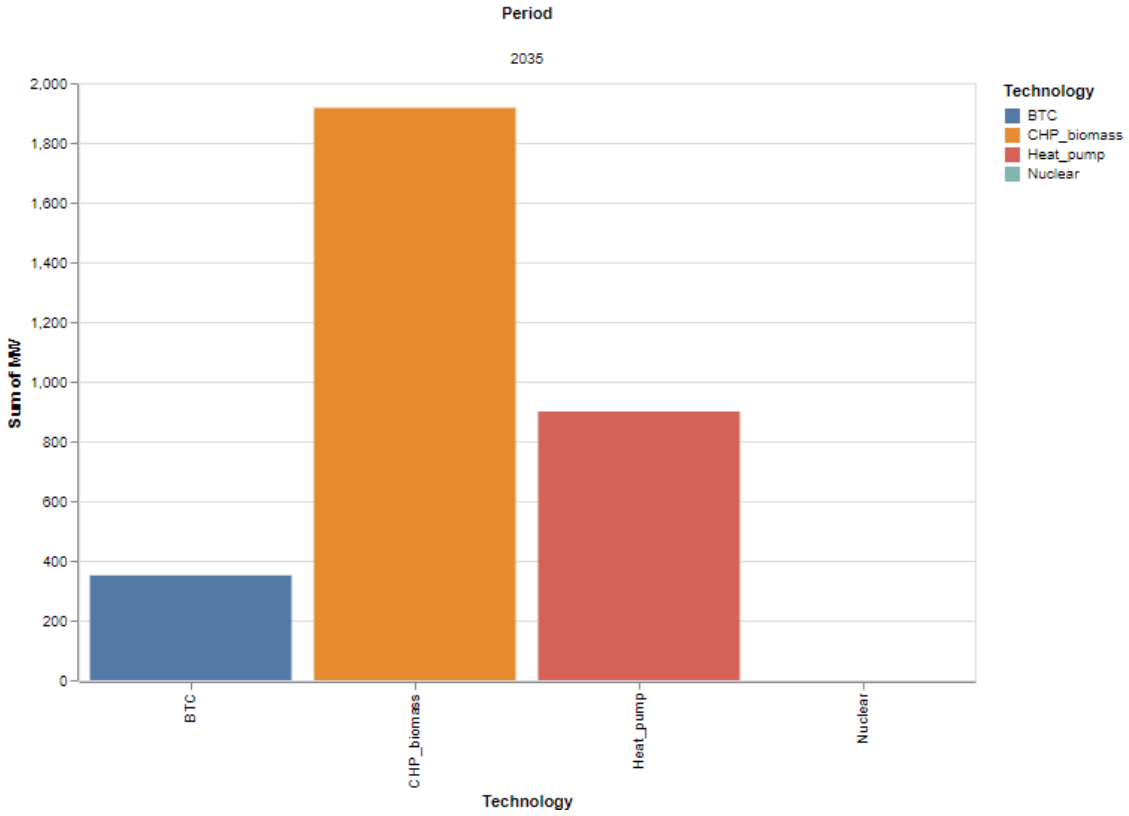

Figure 21: Invested technologies in all three cases. Upper figure corresponds to '2035 with BTC case', middle figure corresponds to '25% lower BTC CAPEX' case and lower figure corresponds to '40% lower biomass price' case.

Accordingly, the total system cost is changing in '**25% lower BTC CAPEX**' case due to decrease in BTC investment cost; see Table 52. Similarly, the operational cost is decreasing in '**40% lower biomass price**' case due to lower biomass prices.

Table 52: Economic dispatch cost components for all cases (MEUR).

Economic Metric	2035 with BTC	25% lower BTC CAPEX	40% lower biomass price
Total system cost	1086,6	1048	974
Investment cost	525	500	525
Operational cost	374.13	374.13	261.6
Consumption operation cost	0.1	0.1	0.1
Emission cost	186	186	186
Reliability Cost	1.3	5.64	1.3

Electricity/heat generation/consumption volumes per technology are presented in Table 53 and Table 54. The tables show no significant difference in electricity/heat dispatched volumes among considered three cases.

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Table 53: Electricity generation/consumption per technology (GWh). Consumption is indicated with negative volumes.

Technology	2035 with BTC	25% lower BTC CAPEX	40% lower biomass price
BTC	32.8	34.0	32.52
CHP_biomass	7533.6	7531.9	7534
CHP_waste	1747.2	1747.2	1747
DSM_generation	436	436	436
DSM_consumption	-436	-436	-436
Heat_boiler	0	0.0	0
Heat_pump	-9783.3	-9784.6	-9783
Hydro_reservoir	79850.0	79850.0	79850
Nuclear	42556.6	42558.0	42556
Solar	12609.6	12607.3	12609
Wind_offshore	10631.0	10629.6	10631
Wind_onshore	68589.0	68592.6	68589
ENS	0.13	0.56	0.13

Table 54: Heat generation/consumption per technology (GWh).

Technology	2035 with BTC	25% lower BTC CAPEX	40% lower biomass price
BTC	20.8	21.5	20.6
CHP_biomass	22601	22595.6	22601.7
CHP_waste	5242	5241.6	5241.6
Heat_boiler	2.0	2.4	2.0
Heat_pump	29352.8	29356.7	29352.0
HNS	0	0	0

Small curtailment of non-dispatchable generation units happens in all three studied cases; see *Table 55*.

Table 55: Curtailment of non-dispatchable generation units (GWh).

Technology	2035 with BTC	25% lower BTC CAPEX	40% lower biomass price
Solar	15,2	19,6	16
Wind_offshore	9,7	13,4	10
Wind_onshore	10,8	2,4	9,6

Finally, LCOE and LCOH per invested technology and for all three cases are briefed in *Table 56*. LCOH for heat pump technology is the lowest for all three cases. The second lowest LCOE and LCOH values has CHP_Biomass technology. LCOE and LCOH values are highest in all three cases. BTC LCOE and LCOH values are lower for the case of '***25% lower BTC CAPEX***' due to 25% decrease in BTC CAPEX.

Table 56: LCOE and LCOH per invested technology (EUR/MWH).

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Technology	2035 with BTC		25% lower BTC CAPEX		40% lower biomass price	
	LCOE	LCOH	LCOE	LCOH	LCOE	LCOH
BTC	2392.7	3785	1813.7	2869	2416.5	3823
CHP_biomass_new	76.8	25.6	72.9	24.3	69.4	23.13
Heat_pump_new	.	2.5	.	2.5	.	2.43
Nuclear_new	.	.	.	.	.	.

To summarise the results obtained from all cases simulated for the reference year of 2035, we conclude that to satisfy system electric demand the model prioritise BTC investment over nuclear technology. However, for a situation that the need for investment in heat generating technologies is higher to meet the system heat demand than that of for electricity, the model prefers to invest more in CHP_biomass than in BTC technology. This behaviour is consistent even if we decrease BTC CAPEX by 25 %. Such a decrease in BTC CAPEX results in 2.44 MEUR/MW, while CHP_biomass has CAPEX of 2.94 MEUR/MW. In a system where there is bigger need to invest in heat generating technology to meet the heat demand than that of electricity, the model prefers to invest in CHP_biomass technology as every MW of electric power installed for CHP, the system gets 3 MW of heat power(with a CAPEX of 2.94 MEUR/MWe), while for BTC, the system only gets 0.63 MW of heat power installed (with a CAPEX of 2.4 MEUR/MWe).

4.9 Results and discussions-Sweden 2045

This section summarises the Swedish energy system simulation results for the reference year 2045. The heat and electricity generation per technology and per price zone, resulting average SRMC prices per price zone, curtailment from non-dispatchable sources and emission from non-renewable sources for the case of '2045 with BTC' are summarised in Table 57. Table 57 also shows that for the reference year 2045 BTC technology is getting invested in all price zones. In SE1 invested volume in BTC technology is about 4 times higher than that of in CHP_biomass technology. In addition, nuclear technology is getting invested to meet electricity demand of reference year 2045. Please note that, in 2045 it is predicted to experience huge increase in electricity demand in SE1 due to fossil free steel industry and electrolysers. The model dispatches all existing and invested technologies to satisfy electricity demand in all price zones, however the SE1-SE2 transmission line is getting congested as it is shown in Figure 22 resulting in very high average prices for SE1; please see Table 57. The other transmission lines are not congested, thus resulting the same average prices for SE2, SE3 and SE4. Very high average SRMC value in SE1 indicates that there are number of hours during the year experiencing electricity shortage. Table 59 shows that for the '2045 with BTC' case not served energy for the entire year is 141 GWh.

Table 57: Heat and electricity generation, average prices, curtailment, and emission values per technology for 2045 with BTC.

	Electricity Generation				Heat Generation			
Existing Technology (GWh)	SE1	SE2	SE3	SE4	SE1	SE2	SE3	SE4
Hydro	24002	42128	12246	1468	.	.	.	.
Nuclear	.	.	46232	.	.	.	.	.
Solar	3290	7714	6636	3604	.	.	.	.

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Wind Onshore	10780	26660	21906	17588	.	.	.	.
Wind offshore	3748	10120	9092	4302	.	.	.	.
CHP_waste	42	229	1118	332	126	687	3354	996
DSR	2180	87	1387	105	.	.	.	.
Candidate for investment								
Nuclear_new	.	.	22940	.	.	.	.	.
CHP_biomass _new	5260	0	1636	1594	15780	0	4912	4782
BTC	12776	26	878	611	8034	16	552	384
Heat_pump_new	.	.	.	.	0	2236	9704	5707
CHP_waste_new	130	0	0	0	392	0	0	0
Economics								
SRMC (EUR/MWh)	237.7	37.7	37.7	37.7				

	RES (%)	Fossil (%)	Electric (%)
Electricity Generation	98.14	0.61	1.24
Heat Generation	59.76	9.64	30.60

Condidate for investment	Investment electricity (MW)	Investment Heat (MW)	LCOE (EUR/MWh)	LCOH (EUR/MWh)
Nuclear_new	2750	.	37.7	.
CHP_biomass_new	1913	5739	46.36	15.45
BTC	7920	3586	124	197.38
Heat_pump_new	.	1217	.	3.9
CHP_waste_new	15	45	64	21.38

Technology (GWh)	El consumption (GWh)	Curtailment (GWh)	Emission (MtCO2)
Hydro	.	.	.
Nuclear	.	.	.
Solar	.	31.4	.
Wind Onshore	.	86	.
Wind offshore	.	75	.
CHP_biomass	.	.	.
CHP_waste	.	.	2.2
Heat pump	5883	.	.
DSR	3760	.	.

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Figure 22: Map of Swedish network resulted from simulation of 2045 case. The red color means the line is congested.

Similarly, Table 58 presents the results of the reference year 2045, '2045 w/o BTC' case. In this case BTC technology is not available to invest. Thus, the model invests mostly in heat-pumps, nuclear, CHP_waste and CHP_biomass to meet the heat and electricity demand. Results presented in Table 58 show that to satisfy heat and electricity demand the model invests in nuclear technology by 100%, in CHP_biomass and in CHP_waste by 100% located in SE1. Heat-pump technology is getting invested only in SE2 and SE4. The absence of BTC technology to invest in '2045 w/o BTC' case resulted even bigger volume of not served electricity (see Table 59) and thus, higher SRMC values (see Table 58). In this context the not served energy volume increased by about 16 times and the SRMC value in SE1 increased by 9 times and in other price zones increased by about 2 times.

Table 58: Heat and electricity generation, average prices, curtailment, and emission values per technology for 2045 with BTC.

	Electricity Generation				Heat Generation			
Existing Technology (GWh)	**SE1**	**SE2**	**SE3**	**SE4**	**SE1**	**SE2**	**SE3**	**SE4**
Hydro	24002	42128	12246	1468	.	.	.	.
Nuclear	.	.	18356	.	.	.	.	.
Solar	3272	7704	6638	3589	.	.	.	.
Wind Onshore	10713	26660	21906	17572	.	.	.	.
Wind offshore	3694	10116	9089	4290	.	.	.	.
CHP_waste	42	166.0	493.6	183.6	126	499	1483	551
DSR	1642	28	308	31.8	.	.	.	.
Candidate for investment								
Nuclear_new	.	.	50024	.	.	.	.	.

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CHP_biomass _new	17414	0	0	0	52247	0	0	0
BTC	.	.	.	.	.	.	.	.
Heat_pump_new	.	.	.	.	0	743	0	1631
CHP_waste_new	130	0	0	0	390	0	0	0
Economics								
SRMC	2162	72.7	72.7	72.7				

	RES (%)	Fossil (%)	Electric (%)
Electricity Generation	99.65	0.35	0.68
Heat Generation	90.6	5.28	4

Candidate for investment	Investment electricity (MW)	Investment heat (MW)	LCOE (EUR/MWH)	LCOH (EUR/MWH)
Nuclear_new	7800	.	49	.
CHP_biomass_new	3561	10683	42	14
BTC	.	.	.	.
Heat_pump_new		1399	.	11.33
CHP_waste_new	15	45	64	21.38

Existing Technology (GWh)	El consumption (GWh)	Curtailment (GWh)	Emission (MtCO2)
Hydro	.	.	.
Nuclear	.	.	.
Solar	.	116	.
Wind Onshore	.	258	.
Wind offshore	.	219	.
CHP_biomass	.	.	.
CHP_waste	.	.	1.08
Heat pump	791	.	.
DSR	2010	.	.

Table 59 summarises the cost components together with system balance for both '2045 with BTC' and '2045 w/o BTC' cases. Obviously, the case without BTC technology results in higher investment cost and huge reliability cost; thus, about 4 times higher total system cost.

Table 59: Swedish system costs and balance with/without BTC 2045.

Cost Type	2045 with BTC (MEUR)	2045 w/o BTC (MEUR)
Total system cost	**5765**	**26619**
Investment cost	3112	3225
Operational cost	1022	810.6
Consumption operation cost	0.1	0.028
Emission cost	220	108
Reliability Cost	1410	22476

System balance		

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Heat Not served (GWh)	0	0
Electricity not served (GWh)	141	2247

4.10 Sensitivity analyses-Sweden 2045

Sensitivity analyses are carried out to investigate the system behaviour in the reference year 2045. We could note from section 4.9 that in both '2045 with BTC' and '2045 w/o BTC' cases we had shortage of electricity in SE1, with not served energy volume equal 141 and 2247 GWh respectively. We studied the system behaviour while adding 3,500 MW of virtual generator to SE1 with 125 Euro/MWh generating cost. In fact, this is interconnectors capacity that SE1 has with neighbouring countries. In addition, we analysed a simulation where 3,500 MW of virtual generator is available at SE1 and BTC CAPEX is 25 % lower. *Table 60* summarises and *Figure 23* depicts the invested volumes per technology for all three cases. BTC technology, CHP_biomass as well as nuclear technology are getting invested in all three cases. We can observe that with extra electric capacity at SE1 '3500 MW VG', where the shortage of electricity is not as sharp as in the case of '2045 with BTC', BTC investment decreased by 44% and CHP_biomass investment increased by 37%. The investment in nuclear, heat-pump and CHP_waste technologies are nearly identical for '2045 with BTC' and '3500 MW VG' cases. However, 25% decrease in BTC CAPEX increased BTC investment volume and decreased nuclear investment volume compared that of '3500 MW VG' case.

Table 60: Invested volume per technology (MW) (VG-virtual generator).

	2045 with BTC		3500 MW VG		25% lower BTC CAPEX	
Technology	Investment electricity	Investment heat	Investment electricity	Investment heat	Investment electricity	Investment heat
BTC	7920	3586	4410	2756	6337	3960
CHP_biomass _new	1913	5739	2625	7875	2266.6	6799.8
Heat_pump _new	.	1217	.	2023	.	779
Nuclear_new	2750	.	2023.5	.	581.5	.
CHP_waste _new	15	45	15	45	0	0

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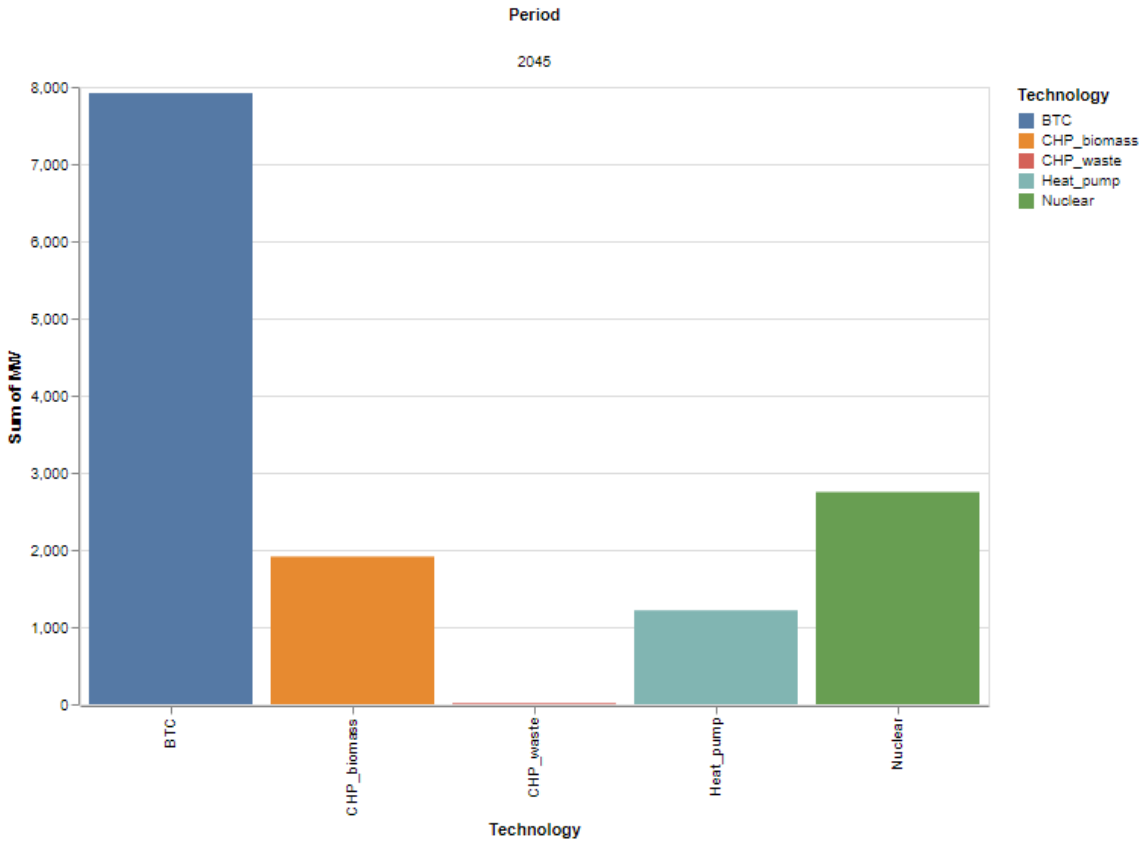

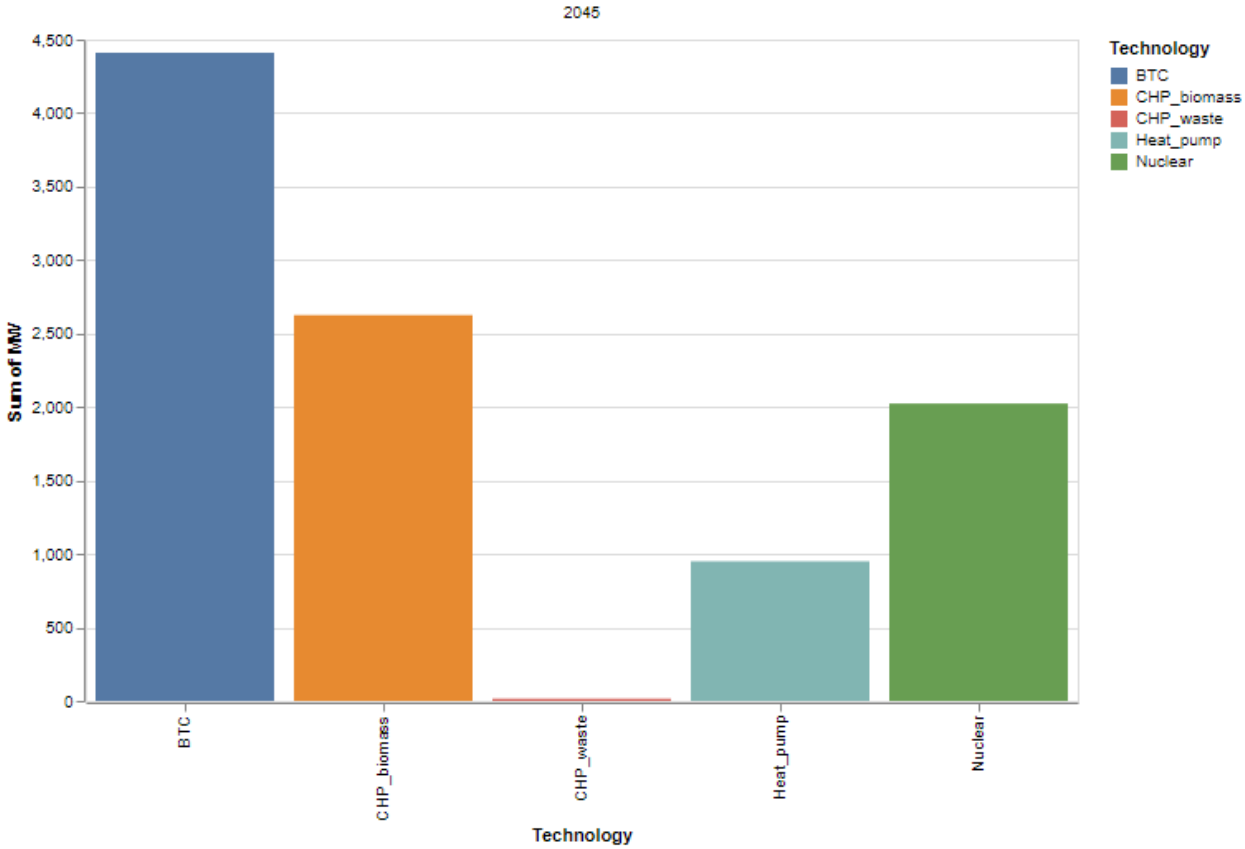

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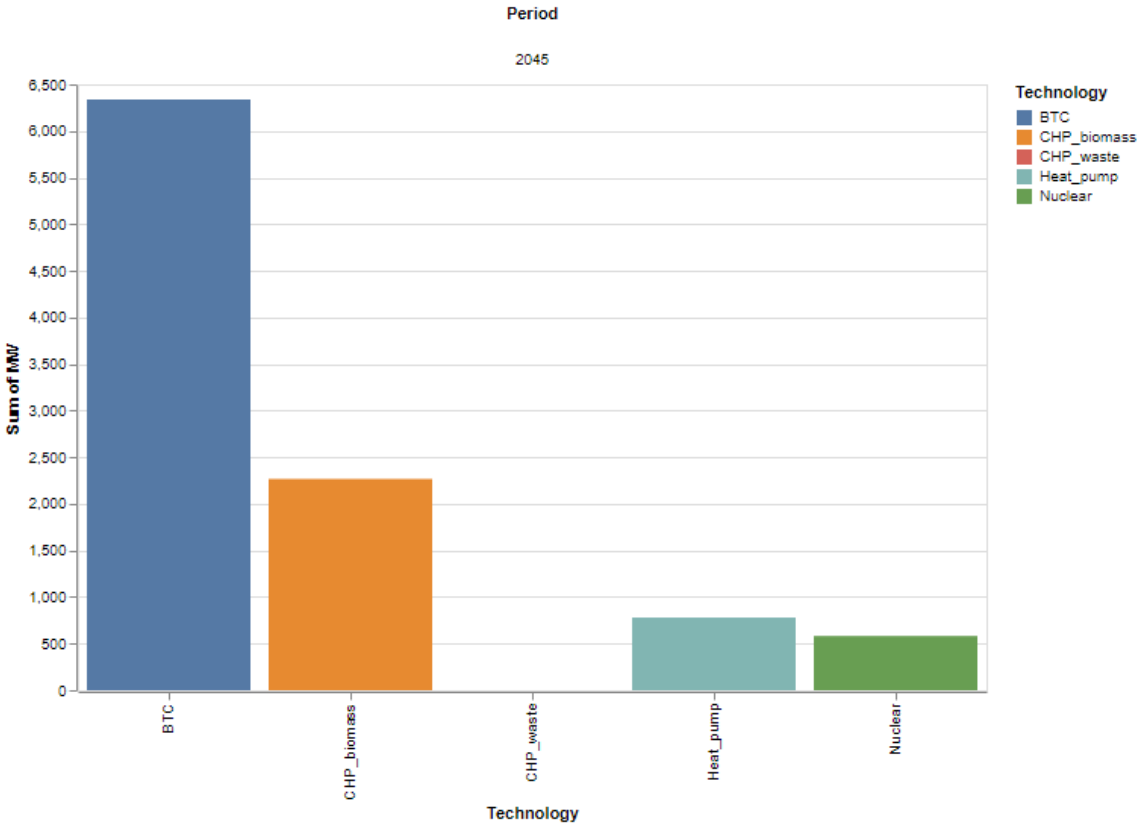

Figure 23: Invested technologies in all three cases. Upper figure corresponds to '2045 with BTC case', middle figure corresponds to '3500 MW VG' case and lower figure corresponds to '25% lower BTC case'.

Economic dispatch cost components are set out in Table 61 and Electricity generation per technology is presented in Table 62. The investment cost decreases in both '3500 MW VG' as well as in '25% lower BTC CAPEX' cases. In this context, the energy not served volume is decreasing by 94.5% in '3500 MW VG' case and 95.6% in '25% lower BTC CAPEX'; see *Table 62*. This results in a sharp reduction in reliability cost (*Table 61*).

Table 61: Economic dispatch cost components for all cases (MEUR) (VG-virtual generator).

Economic Metric	2045 with BTC	3500 MW VG	25% lower BTC CAPEX
Total system cost	**5765**	**3662**	**3334**
Investment cost	3112	2228.7	1759
Operational cost	1022	1158.7	1330
Consumption operation cost	0.1	0.07	0.06
Emission cost	220	197	183.5
Reliability Cost	1410	77.8	61.7

Table 62 and Table 63 show that BTC technology is highly dispatched in the third case, thus resulting lower LCOE and LCOH values compared to that of the other two cases (first and second columns) *Table 65*.

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Table 62: Electricity generation per technology (GWh) (VG-virtual generator).

Technology	2045 with BTC	3500 MW VG	25% lower BTC CAPEX
BTC	14292.6	12489.9	17154
CHP_biomass	8492.0	11076.0	11090
CHP_waste	1853.0	1846.99	1718
DSM_generation	3760	3676	3740
Hydro_reservoir	79850.0	79850.0	79850
Nuclear	69174.0	65445.0	60094
Solar	21249.0	21265.7	21237
Wind_offshore	27264.0	27265.7	27253
Wind_onshore	76936.0	76934.5	76931.6
VG	.	894.0	854
Energy Not Served	142	7.78	6.2

Table 63: Heat generation per technology (GWh) (VG-virtual generator).

Technology	2045 with BTC	3500 MW VG	25% lower BTC CAPEX
BTC	8987.4	7853.8	10787.0
CHP_biomass	25476	33228.7	33271.0
CHP_waste	5558	5541.0	5153.6
Heat_pump	17650.0	11047.6	8459.0
Heat Not Served	0	0	0

Table 64: Curtailment of non-dispatchable generation units (GWh) (VG-virtual generator).

Technology	2045 with BTC	3500 MW VG	25% lower BTC CAPEX
Solar	31.4	48	55.4
Wind_onshore	86	90	96
Wind_offshore	75	72	97

Table 65: LCOE and LCOH per invested technology (EUR/MWh) (VG-virtual generator).

Technology	2045 with BTC		3500 MW VG		25% lower BTC CAPEX	
	LCOE	LCOH	LCOE	LCOH	LCOE	LCOH
BTC	124	197.4	79	125.8	62	98.7
CHP_biomass_new	46.36	15.45	48.77	16.25	42	14
Heat_pump_new	.	3.9	.	4.95	.	5.3
Nuclear_new	37.7	.	37.6	.	55.7	.

Marginal costs for all cases are shown in Table 66. We see that SE3 and SE4 are keeping the same price values in all three cases. The SRMC value decreases gradually in SE2, while in SE1 SRMC value decreases sharply due to extra 3500 MW electric capacity introduced to SE1.

Table 66: Marginal cost for all cases (EUR/MWh).

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	2045 with BTC	3500 MW VG	25% lower BTC CAPEX
SE1	237	59.9	54
SE2	37.7	36	35.5
SE3	37.7	37.7	37.7
SE4	37.7	37.7	37.7

To summarise the results obtained from all cases simulated for the reference year of 2045, we conclude that integrating BTC technology in the generation mix of 2045 energy system has the opposite effect that we observed while integrating BTC technology in 2035 Swedish energy system. In 2045 reference case, where the need for investment in electricity generating technologies is higher to meet the system electric demand than that of for heat, the model always finds it efficient to invest more in BTC technology than in other technologies.

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5 Conclusions

This deliverable evaluates the integration and profitability of the BTC technology in Swedish and Spanish electricity and heat systems using a single modelling tool: openTEPES. The conclusions of this deliverable are divided between the Spanish and Swedish cases, as stated below.

5.1 Conclusions Spanish scenarios

According to the Spanish Energy and Climate Plan, the Spanish electricity system for 2030 is expected to have 81% of renewable electricity generation and 100% in 2050. For 2030, with BTC renewable generation surpassed the 81% threshold.

Results for the Spanish 2030 scenarios show that, under the modelling assumptions made, BTC is a competitive technology and can participate in both the electricity and heat mix, even when competing with conventional biomass CHP technology. Including BTC also leads to lower electricity marginal costs and increases shares of renewable generation in both the electricity and heat sectors. Additionally, results show that cogeneration and electric heat technologies, (electric boilers and heat pumps), are preferred before carbon-emitting boilers, even when these present lower investment costs. On the other side, hydrogen boilers, although they can contribute to decarbonize heat production by using a renewable fuel, their high CAPEX values make them a non-competitive technology in comparison. Three different sensitivities were modelled: increase in biomass prices and CO2 emission ETS price and the efficiency of conventional CHP. In all cases, the BTC investment did not change, and the heat and electricity generation of BTC changed marginally only.

As for 2050, with the initial assumptions, results show that BTC technology is not as competitive, getting no investments in the main scenarios, mainly due to its high CAPEX value compared to conventional biomass CHP technology. However, the model decides to invest in BTC when considering a small reduction of 10% in their investment cost. Electrification of heat production reaches above 80%, with biomass boilers and CHPs complementing the mix. In addition, higher biomass prices make generation of CHP and biomass boilers less attractive and BTC, due to higher efficiency, more competitive.

5.2 Conclusions Swedish scenarios

The Swedish TSO has developed different scenarios/economic pathways to analyse long term market behaviour towards green transition. Swedish cases for the reference years of 2035 and 2045 are created adopting a long-term market scenario and a set of modelling assumptions. Several simulations are conducted for 2035 and 2045 Swedish energy system. It is important to notice that conclusions are extracted based on the results obtained from simulations under certain modelling assumptions. To generalise the results more simulation runs, and broader sensitivity analyses need to be carried out.

The results obtained from all cases simulated for the reference year of 2035 show that to satisfy the system electric demand the model prioritises BTC investment over nuclear technology. However, for a situation that the need for investment in heat generating technologies is higher to meet the system heat demand than that of electricity, the model prefers to invest in CHP biomass rather than

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in BTC technology. This behaviour is consistent even if we decrease BTC CAPEX by 25 %. Such a decrease in BTC CAPEX results in 2.44 MEUR/MW, while CHP biomass has CAPEX of 2.94 MEUR/MW. To summarize, in a system where there is a bigger need to invest in heat generating technology to meet the heat demand than that of electricity, the model prefers to invest in CHP biomass technology as every MW of electric power installed for CHP, the system gets 3 MW of heat power installed (with a CAPEX of 2.94 MEUR/MWe), while for BTC, the system only gets 0.63 MW of heat power installed (with a CAPEX of 2.4 MEUR/MWe).

Integrating BTC technology in the generation mix of 2045 energy system we experience the opposite effect that we observed while integrating BTC technology in 2035 Swedish energy system. In 2045 reference case, where the need for investment in electricity generating technologies is higher to meet the system electric demand than that of for heat, the model always finds BTC technology more competitive to invest in than other technologies. All simulations for the 2045 Swedish energy system under the modelling assumptions made highlighted that BTC is a competitive technology and can participate in both electricity and heat mix and contribute to satisfy both system electricity and heat demand.

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Annex 1: openTEPES Mathematical formulation

This Annex presents the mathematical formulation of openTEPES model. The model has been updated to include the heat sector: demand and heat generators. The Annex descript the indices of variables and parameters and the model equations. As the model is continuously updated, this version represents the one used in the deliverable.

Indices

p	Period (e.g., year)
ω	Scenario
n	Load level (e.g., hour)
g	Generator (thermal or hydro unit or energy storage system)
t	Thermal unit
e	Energy Storage System (ESS)
h	Hydropower or pumped-storage hydro plant (associated to a reservoir modeled in water units)
e', e''	Reservoir (natural water inflows in m^3/s and volume in hm^3)
$h \in up(e')$	Hydro or pumped-storage hydropower plant h upstream of reservoir e'
$h \in dw(e')$	Hydro or pumped-storage hydropower plant h downstream of reservoir e'
$e'' \in up(e')$	Reservoir e'' upstream of reservoir e'
i, j	Node
z	Zone. Each node belongs to a zone $i \in z$
a	Area. Each zone belongs to an area $z \in a$
r	Region. Each area belongs to a region $a \in r$
c	Circuit
ijc	Line (initial node, final node, circuit)
cy	Electricity network cycle
CY	Electricity network cycle basis
CLC	AC candidate electricity transmission lines in a certain cycle
EG, CG	Set of existing and candidate generators
EB, CB	Set of existing and candidate fuel heaters
EE, CE	Set of existing and candidate ESS
ER, CR	Set of existing and candidate reservoirs
EL, CL	Set of existing and non-switchable, and candidate and switchable electric transmission lines
EP, CP	Set of existing and candidate pipelines

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Parameters

They are written in **uppercase** letters.

General

T Base period (year) year

ν Time step. Duration of the load levels (e.g., 2 h, 3 h)

δ Annual discount rate p.u.

WG^p Period (year) weight p.u.

DF^p Discount factor for each period (year) p.u.

Electricity demand

$D^p_{\omega ni}$ Electricity demand in each node GW

PD_{pa} Peak demand in each area GW

$DUR^p_{\omega n}$ Duration of each load level h

$CENS$ Cost of energy not served. Value of Lost Load (VoLL) €/MWh

Hydrogen demand

$DH^p_{\omega ni}$ Hydrogen demand in each node tH2

$CHNS$ Cost of hydrogen not served €/tH2

Heat demand

$DHt^p_{\omega ni}$ Heat demand in each node GW

$CHtNS$ Cost of heat not served €/MWh

Scenarios

P^p_{ω} Probability of each scenario in each period p.u.

Operating reserves

URA, DRA Upward and downward reserve activation p.u.

$DtUR, \overline{DtUR}$ Minimum and maximum ratios downward to upward operating reserves p.u.

$UR^p_{\omega na}, DR^p_{\omega na}$ Upward and downward operating reserves for each area GW

Adequacy system reserve margin

RM_{pa} Minimum adequacy system reserve margin for each period and area p.u.

Maximum CO2 emission

EL_{pa} Maximum CO2 emission for each period, scenario, and area MtCO2

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Minimum RES energy

RL_{pa} Minimum RES energy for each period, scenario, and area	GWh

System inertia

$SI^{p}_{\omega na}$ System inertia for each area s	

Generation system

CFG_g Annualized fixed cost of a candidate generator	M€/yr
CFR_g Annualized fixed cost of a candidate generator to be retired	M€/yr
A_g Availability of each generator for adequacy reserve margin	p.u.
$GP_g, \overline{GP}_g$ Rated minimum load and maximum output of a generator	GW
$GP^{p}_{\omega ng}, \overline{GP}^{p}_{\omega ng}$ Minimum load and maximum output of a generator	GW
$GC^{p}_{\omega ne}, \overline{GC}^{p}_{\omega ne}$ Minimum and maximum consumption of an ESS	GW
$GH_g, \overline{GH}_g$ Rated minimum and maximum heat of a CHP or a fuel heater	GW
$CF^{p}_{\omega ng}, CV^{p}_{\omega ng}$ Fixed (no load) and variable cost of a generator. Variable cost includes fuel and O&M	€/h, €/MWh
$CE^{p}_{\omega ng}$ Emission cost of a generator	€/MWh
ER_g Emission rate of a generator	tCO2/MWh
CV_e Variable cost of an ESS or pumped-storage hydropower plant when charging	€/MWh
RU_g, RD_g Ramp up/down of a non-renewable unit or maximum discharge/7% for ESS discharge/charge	MW/h
TU_t, TD_t Minimum uptime and downtime of a thermal unit	h
ST_e Maximum shift time of an ESS unit (in particular, for demand side management)	h
CSU_g, CSD_g Startup and shutdown cost of a committed unit	M€
τ_e Storage cycle of the ESS (e.g., 1, 24, 168, 8736 h -for daily, weekly, monthly, yearly-)	h
ρ_e Outflow cycle of the ESS (e.g., 1, 24, 168, 8736 h -for hourly, daily, weekly, monthly, yearly-)	h
σ_g Energy cycle of the unit (e.g., 24, 168, 672, 8736 h -for daily, weekly, monthly, yearly-)	h
GI_g Generator inertia	s
EF_e Round-trip efficiency of the pump/turbine cycle of a pumped-storage hydro plant or charge/discharge of a battery	p.u.
PF_h Production function from water inflows to electricity	kWh/m^3
PF'_e Production function from electricity to hydrogen of an electrolyzer	kWh/kgH2

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Generation system

PF''_e Production function from electricity to heat of a heat pump or an electrical heater	kWh/kWh
PH''_g Power to heat ratio for a CHP $\frac{\overline{GP}_g - GP_g}{\overline{GH}_g - GH_g}$	kWh/kWh
$I^p_{\omega ne}, \overline{I}^p_{\omega ne}$ Minimum and maximum storage of an ESS (e.g., hydropower plant, closed-/open-loop pumped-storage hydro)	GWh
$I^p_{\omega e}$ Initial storage of an ESS (e.g., hydropower plant, closed-/open-loop pumped-storage hydro)	GWh
$E^p_{\omega ne}, \overline{E}^p_{\omega ne}$ Minimum and maximum energy produced by a unit in an interval defined	GW
$EI^p_{\omega ne}$ Energy inflows of an ESS (e.g., hydropower plant)	GW
$EO^p_{\omega ne}$ Energy outflows of an ESS (e.g., hydrogen, electric vehicle, hydropower plant, demand response)	GW

Hydropower system

$CFE_{e'}$ Annualized fixed cost of a candidate reservoir	M€/yr
$I'^p_{\omega ne'}, \overline{I'}^p_{\omega ne'}$ Minimum and maximum volume of a reservoir	hm^3
$HI^p_{\omega ne'}$ Natural water inflows of a reservoir	m^3/s
$HO^p_{\omega ne'}$ Hydro outflows of a reservoir (e.g., irrigation)	m^3/s

Electricity transmission system

CFT_{ijc} Annualized fixed cost of a candidate electricity transmission line	M€/yr
$\overline{F}_{ijc}$ Net transfer capacity (total transfer capacity multiplied by the security coefficient) of a transmission line	GW
$\overline{F}'_{ijc}$ Maximum flow used in the Kirchhoff's 2nd law constraint (e.g., disjunctive constraint for the candidate AC lines)	GW
L_{ijc} Loss factor of an electric transmission line	p.u.
X_{ijc} Reactance of an electric transmission line	p.u.
SON_{ijc}, SOF_{ijc} Minimum switch-on and switch-off state of a line	h
S_B Base power	GW
$\overline{\theta}'_{cy,i'j'c'}$ Maximum angle used in the cycle Kirchhoff's 2nd law constraint (i.e., disjunctive constraint for a cycle with some AC candidate lines)	rad

The net transfer capacity of an electric transmission line can be different in each direction. However, here it is presented as equal for simplicity.

Hydrogen transmission system

CFH_{ijc} Annualized fixed cost of a candidate hydrogen transmission pipeline	M€/yr

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Hydrogen transmission system

$\overline{FH}_{ijc}$ Net transfer capacity (total transfer capacity multiplied by the security coefficient) of a pipeline tH2

The net transfer capacity of a hydrogen transmission pipeline can be different in each direction. However, here it is presented as equal for simplicity.

Heat transmission system

CFP_{ijc} Annualized fixed cost of a candidate heat pipe M€/yr

$\overline{FP}_{ijc}$ Net transfer capacity (total transfer capacity multiplied by the security coefficient) of a heat pipe GW

The net transfer capacity of a heat pipe can be different in each direction. However, here it is presented as equal for simplicity.

Variables

They are written in **lowercase** letters.

Electricity demand

$ens^{p}_{\omega ni}$ Energy not served GW

Hydrogen demand

$hns^{p}_{\omega ni}$ Hydrogen not served tH2

Heat demand

$htns^{p}_{\omega ni}$ Heat not served GW

Generation system

icg^{p}_{g} Candidate generator or ESS installed or not {0,1}

rcg^{p}_{g} Candidate generator or ESS retired or not {0,1}

$gp^{p}_{\omega ng}, gc^{p}_{\omega ng}$ Generator output (discharge if an ESS) and consumption (charge if an ESS) GW

$go^{p}_{\omega ne}$ Generator outflows of an ESS GW

$p^{p}_{\omega ng}$ Generator output of the second block (i.e., above the minimum load) GW

$c^{p}_{\omega ne}$ Generator charge GW

$gh^{p}_{\omega ng}$ Heat output of a fuel heater GW

$ur^{p}_{\omega ng}, dr^{p}_{\omega ng}$ Upward and downward operating reserves of a non-renewable generating unit GW

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Generation system

$ur'^{p}_{\omega ne}, dr'^{p}_{\omega ne}$ Upward and downward operating reserves of an ESS as a consumption unit GW

$ei^{p}_{\omega ne}$ Variable energy inflows of a candidate ESS (e.g., hydropower plant) GW

$i^{p}_{\omega ne}$ ESS stored energy (inventory, reservoir energy, state of charge) GWh

$s^{p}_{\omega ne}$ ESS spilled energy GWh

$uc^{p}_{\omega ng}, su^{p}_{\omega ng}, sd^{p}_{\omega ng}$ Commitment, startup and shutdown of generation unit per load level {0,1}

uc'_{g} Maximum commitment of a generation unit for all the load levels {0,1}

Hydropower system

icr^{p}_{e}, Candidate reservoir installed or not {0,1}

$hi^{p}_{\omega ne}$, Variable water inflows of a candidate reservoir (e.g., hydropower plant) m^3/s

$ho^{p}_{\omega ne}$, Hydro outflows of a reservoir m^3/s

$i'^{p}_{\omega ne}$, Reservoir volume hm^3

$s'^{p}_{\omega ne}$, Reservoir spilled water hm^3

Electricity transmission system

ict^{p}_{ijc} Candidate transmission installed or not {0,1}

$swt^{p}_{\omega nijc}, son^{p}_{\omega nijc}, sof^{p}_{\omega nijc}$ Switching state, switch-on and switch-off of an electric line {0,1}

$f^{p}_{\omega nijc}$ Power flow through an electric line GW

$l^{p}_{\omega nijc}$ Half ohmic losses of an electric line GW

$\theta^{p}_{\omega ni}$ Voltage angle of a node rad

Hydrogen transmission system

ich^{p}_{ijc} Candidate hydrogen pipeline installed or not {0,1}

$fh^{p}_{\omega nijc}$ Hydrogen flow through a hydrogen pipeline tH2

Heat transmission system

icp^{p}_{ijc} Candidate heat pipe installed or not {0,1}

$fp^{p}_{\omega nijc}$ Heat flow through a heat pipe GW

Equations

The names between parenthesis correspond to the names of the constraints in the code.

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Objective function: minimization of total (investment and operation) cost for the multi-period scope of the model

Electricity, heat, and hydrogen generation, (energy and reservoir) storage and (electricity, hydrogen, and heat) network investment cost plus retirement cost [M€] «*eTotalFCost*»

$$\sum_{pg} D\,F^p CFG_g icg_g^p + \sum_{pg} D\,F^p CFR_g rcg_g^p + \sum_{pe'} D\,F^p CFE_{e'} icr_{e'}^p + \sum_{pijc} D\,F^p CFT_{ijc} ict_{ijc}^p + \sum_{pijc} D\,F^p CFH_{ijc} ich_{ijc}^p + \sum_{pijc} D\,F^p CFP_{ijc} icp_{ijc}^p +$$

Electricity, heat, and hydrogen generation operation cost [M€] «*eTotalGCost*»

$$\sum_{p\omega ng} \left[DF^p P_\omega^p DUR_{\omega n}^p \left(CV_{\omega ng}^p gp_{\omega ng}^p + CF_{\omega ng}^p uc_{\omega ng}^p\right) + DF^p CSU_g su_{\omega ng}^p + DF^p CSD_g sd_{\omega ng}^p\right] +$$

Generation emission cost [M€] «*eTotalECost*»

$$\sum_{p\omega ng} DF^p P_\omega^p DUR_{\omega n}^p CE_{\omega ng}^p gp_{\omega ng}^p +$$

Variable consumption operation cost [M€] «*eTotalCCost*»

$$\sum_{p\omega ne} DF^p P_\omega^p DUR_{\omega n}^p CV_e gc_{\omega ne}^p +$$

Electricity, hydrogen, and heat reliability cost [M€] «*eTotalRCost*»

$$\sum_{p\omega ni} DF^p P_\omega^p DUR_{\omega n}^p CENSens_{\omega ni}^p + \sum_{p\omega ni} DF^p P_\omega^p DUR_{\omega n}^p CHNShns_{\omega ni}^p + \sum_{p\omega ni} DF^p P_\omega^p DUR_{\omega n}^p CHtNShtns_{\omega ni}^p$$

All the periodical (annual) costs of a period p are updated considering that the period (e.g., 2030) is replicated for a number of years defined by its weight WG^p (e.g., 5 times) and discounted to the base year T (e.g., 2020) with this discount factor $DF^p = \frac{(1+\delta)^{WG^p}-1}{\delta(1+\delta)^{WG^p-1+p-T}}$.

Constraints

Generation and network investment and retirement

Investment and retirement decisions in consecutive years «*eConsecutiveGenInvest*» «*eConsecutiveGenRetire*» «*eConsecutiveRsrInvest*» «*eConsecutiveNetInvest*» «*eConsecutiveNetH2Invest*»

$$icg_g^{p-1} \le icg_g^p \quad \forall pg, g \in CG$$

$$rcg_g^{p-1} \le rcg_g^p \quad \forall pg, g \in CG$$

$$icr_{e'}^{p-1} \le icr_{e'}^p \quad \forall pe', e' \in CR$$

$$ict_{ijc}^{p-1} \le ict_{ijc}^p \quad \forall pijc, ijc \in CL$$

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$$ich_{ijc}^{p-1} \leq ich_{ijc}^{p} \quad \forall pijc, ijc \in CH$$

$$icp_{ijc}^{p-1} \leq icp_{ijc}^{p} \quad \forall pijc, ijc \in CP$$

Generation operation

Commitment decision bounded by the investment decision for candidate committed units (all except the VRE units) [p.u.] «*eInstallGenComm*»

$$uc_{\omega ng}^{p} \leq icg_{g}^{p} \quad \forall p\omega ng, g \in CG$$

Commitment decision bounded by the investment decision for candidate ESS [p.u.] «*eInstallESSComm*»

$$uc_{\omega ne}^{p} \leq icg_{e}^{p} \quad \forall p\omega ne, e \in CE$$

Output and consumption bounded by investment decision for candidate ESS [p.u.] «*eInstallGenCap*» «*eInstallConESS*»

$$\frac{gp_{\omega ng}^{p}}{\overline{GP}_{\omega ng}^{p}} \leq icg_{g}^{p} \quad \forall p\omega ng, g \in CG$$

$$\frac{gc_{\omega ne}^{p}}{\overline{GP}_{\omega ne}^{p}} \leq icg_{e}^{p} \quad \forall p\omega ne, e \in CE$$

Heat production with fuel heater bounded by investment decision for candidate fuel heater [p.u.] «*eInstallFHUCap*»

$$\frac{gh_{\omega ng}^{p}}{\overline{GH}_{\omega ng}^{p}} \leq icg_{g}^{p} \quad \forall p\omega ng, g \in CB$$

Adequacy system reserve margin [p.u.] «*eAdequacyReserveMargin*»

$$\sum_{g \in a, EG} \overline{GP}_{g} A_{g} + \sum_{g \in a, CG} i\,cg_{g}^{p} \overline{GP}_{g} A_{g} \geq PD_{pa} RM_{pa} \quad \forall pa$$

Maximum CO2 emission [MtC02] «*eMaxSystemEmission*»

$$\sum_{ng} DUR_{\omega n}^{p} CE_{\omega ng}^{p} gp_{\omega ng}^{p} \leq EL_{pa} \quad \forall p\omega a$$

Minimum RES energy [GW] «*eMinSystemRESEnergy*»

$$\frac{\sum_{ng} DUR_{\omega n}^{p} gp_{\omega ng}^{p}}{\sum_{n} DUR_{\omega n}^{p}} \geq \frac{RL_{pa}}{\sum_{n} DUR_{\omega n}^{p}} \quad \forall p\omega a$$

Balance of electricity generation and demand at each node with ohmic losses [GW] «*eBalanceElec*»

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$$\sum_{g\in i} g\, p^{p}_{\omega ng} - \sum_{e\in i} g\, c^{p}_{\omega ne} + ens^{p}_{\omega ni} = D^{p}_{\omega ni} + \sum_{jc} l^{p}_{\omega nijc} + \sum_{jc} l^{p}_{\omega njic} + \sum_{jc} f^{p}_{\omega nijc} - \sum_{jc} f^{p}_{\omega njic} \quad \forall p\omega ni$$

The sum of the inertia of the committed units must satisfy the system inertia for each area [s] «*eSystemInertia*»

$$\sum_{g\in a} G\, I_g uc^{p}_{\omega ng} \geq SI^{p}_{\omega na} \quad \forall p\omega na$$

Upward and downward operating reserves provided by non-renewable generators, and ESS when charging for each area [GW] «*eOperReserveUp*» «*eOperReserveDw*»

$$\sum_{g\in a} u\, r^{p}_{\omega ng} + \sum_{e\in a} u\, r'^{p}_{\omega ne} = UR^{p}_{\omega na} \quad \forall p\omega na$$

$$\sum_{g\in a} d\, r^{p}_{\omega ng} + \sum_{e\in a} d\, r'^{p}_{\omega ne} = DR^{p}_{\omega na} \quad \forall p\omega na$$

Ratio between downward and upward operating reserves provided by non-renewable generators, and ESS when charging for each area [GW] «*eReserveMinRatioDwUp*» «*eReserveMaxRatioDwUp*» «*eRsrvMinRatioDwUpESS*» «*eRsrvMaxRatioDwUpESS*»

$$DtUR\ ur^{p}_{\omega ng} \leq dr^{p}_{\omega ng} \leq \overline{DtUR}\ ur^{p}_{\omega ng} \quad \forall p\omega ng$$

$$DtUR\ ur'^{p}_{\omega ne} \leq dr'^{p}_{\omega ne} \leq \overline{DtUR}\ ur'^{p}_{\omega ne} \quad \forall p\omega ne$$

VRES units (i.e., those with linear variable cost equal to 0 and no storage capacity) do not contribute to the the operating reserves.

Operating reserves from ESS can only be provided if enough energy is available for producing [GW] «*eReserveUpIfEnergy*» «*eReserveDwIfEnergy*»

$$ur^{p}_{\omega ne} \leq \frac{i^{p}_{\omega ne}}{DUR^{p}_{\omega n}} \quad \forall p\omega ne$$

$$dr^{p}_{\omega ne} \leq \frac{\overline{I}^{p}_{\omega ne} - i^{p}_{\omega ne}}{DUR^{p}_{\omega n}} \quad \forall p\omega ne$$

or for storing [GW] «*eESSReserveUpIfEnergy*» «*eESSReserveDwIfEnergy*»

$$ur'^{p}_{\omega ne} \leq \frac{\overline{I}^{p}_{\omega ne} - i^{p}_{\omega ne}}{DUR^{p}_{\omega n}} \quad \forall p\omega ne$$

$$dr'^{p}_{\omega ne} \leq \frac{i^{p}_{\omega ne}}{DUR^{p}_{\omega n}} \quad \forall p\omega ne$$

Maximum and minimum relative inventory of ESS candidates (only for load levels multiple of 1, 24, 168, 8736 h depending on the ESS storage type) constrained by the ESS commitment

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decision times the maximum capacity [p.u.] «*eMaxInventory2Comm*» «*eMinInventory2Comm*»

$$\frac{i^{p}_{\omega ne}}{\overline{I}^{p}_{\omega ne}} \leq uc^{p}_{\omega ne} \quad \forall p\omega ne, e \in CE$$

$$\frac{i^{p}_{\omega ne}}{I^{p}_{\omega ne}} \geq uc^{p}_{\omega ne} \quad \forall p\omega ne, e \in CE$$

Energy inflows of ESS candidates (only for load levels multiple of 1, 24, 168, 8736 h depending on the ESS storage type) constrained by the ESS commitment decision times the energy inflows data [p.u.] «*eInflows2Comm*»

$$\frac{ei^{p}_{\omega ne}}{EI^{p}_{\omega ne}} \leq uc^{p}_{\omega ne} \quad \forall p\omega ne, e \in CE$$

ESS energy inventory (only for load levels multiple of 1, 24, 168 h depending on the ESS storage type) [GWh] «*eESSInventory*»

$$i^{p}_{\omega,n-\frac{\tau_e}{\nu,e}} + \sum_{n'=n-\frac{\tau_e}{\nu}}^{n} DUR^{p}_{\omega n'}\left(EI^{p}_{\omega n' e} - go^{p}_{\omega n' e} - gp^{p}_{\omega n' e} + EF_e gc^{p}_{\omega n' e}\right) = i^{p}_{\omega ne} + s^{p}_{\omega ne} \quad \forall p\omega ne, e \in EE$$

$$i^{p}_{\omega,n-\frac{\tau_e}{\nu,e}} + \sum_{n'=n-\frac{\tau_e}{\nu}}^{n} DUR^{p}_{\omega n'}\left(ei^{p}_{\omega n' e} - go^{p}_{\omega n' e} - gp^{p}_{\omega n' e} + EF_e gc^{p}_{\omega n' e}\right) = i^{p}_{\omega ne} + s^{p}_{\omega ne} \quad \forall p\omega ne, e \in CE$$

The initial inventory of the ESS candidates divided by its initial storage $I^{p}_{\omega e}$ is equal to the final reservoir divide by its initial storage [p.u.] «*eIniFinInventory*».

$$\frac{i^{p}_{\omega,0,e}}{I^{p}_{\omega e}} = \frac{i^{p}_{\omega,N,e}}{I^{p}_{\omega e}} \quad \forall p\omega e, e \in CE$$

The initial inventory of the ESS candidates divided by their initial storage $I^{p}_{\omega e}$ is fixed to the commitment decision [p.u.] «*eIniInventory*».

$$\frac{i^{p}_{\omega,0,e}}{I^{p}_{\omega e}} \leq uc^{p}_{\omega ne} \quad \forall p\omega ne, e \in CE$$

Maximum shift time of stored energy [GWh]. It is thought to be applied to demand side management «*eMaxShiftTime*»

$$DUR^{p}_{\omega n} EF_e gc^{p}_{\omega ne} \leq \sum_{n'=n+1}^{n+\frac{ST_e}{\nu}} DUR^{p}_{\omega n'} gp^{p}_{\omega n' e} \quad \forall p\omega ne$$

ESS outflows (only for load levels multiple of 1, 24, 168, 672, and 8736 h depending on the ESS outflow cycle) must be satisfied [GWh] «*eEnergyOutflows*»

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$$\sum_{n'=n-\frac{\tau_e}{\rho_e}}^{n} \left(go^p_{\omega n' e} - EO^p_{\omega n' e}\right) DUR^p_{\omega n'} = 0 \quad \forall p\omega ne, n \in \rho_e$$

Maximum and minimum energy production (only for load levels multiple of 24, 168, 672, 8736 h depending on the unit energy type) must be satisfied [GWh] «*eMaximumEnergy*» «*eMinimumEnergy*»

$$\sum_{n'=n-\sigma_g}^{n} \left(gp^p_{\omega n' g} - \overline{E}^p_{\omega n' g}\right) DUR^p_{\omega n'} \leq 0 \quad \forall p\omega ng, n \in \sigma_g$$

$$\sum_{n'=n-\sigma_g}^{n} \left(gp^p_{\omega n' g} - E^{\,p}_{\omega n' g}\right) DUR^p_{\omega n'} \geq 0 \quad \forall p\omega ng, n \in \sigma_g$$

Maximum and minimum output of the second block of a committed unit (all except the VRES units) [p.u.] «*eMaxOutput2ndBlock*» «*eMinOutput2ndBlock*»

- D.A. Tejada-Arango, S. Lumbreras, P. Sánchez-Martín, and A. Ramos "Which Unit-Commitment Formulation is Best? A Systematic Comparison" IEEE Transactions on Power Systems 35 (4): 2926-2936, Jul 2020 10.1109/TPWRS.2019.2962024
- C. Gentile, G. Morales-España, and A. Ramos "A tight MIP formulation of the unit commitment problem with start-up and shut-down constraints" EURO Journal on Computational Optimization 5 (1), 177-201, Mar 2017. 10.1007/s13675-016-0066-y
- G. Morales-España, A. Ramos, and J. Garcia-Gonzalez "An MIP Formulation for Joint Market-Clearing of Energy and Reserves Based on Ramp Scheduling" IEEE Transactions on Power Systems 29 (1): 476-488, Jan 2014. 10.1109/TPWRS.2013.2259601
- G. Morales-España, J.M. Latorre, and A. Ramos "Tight and Compact MILP Formulation for the Thermal Unit Commitment Problem" IEEE Transactions on Power Systems 28 (4): 4897-4908, Nov 2013. 10.1109/TPWRS.2013.2251373

$$\frac{p^p_{\omega ng} + ur^p_{\omega ng}}{\overline{GP}^p_{\omega ng} - GP^p_{\omega ng}} \leq uc^p_{\omega ng} - su^p_{\omega ng} - sd^p_{\omega, n+\nu, g} \quad \forall p\omega ng$$

$$p^p_{\omega ng} - dr^p_{\omega ng} \geq 0 \quad \forall p\omega ng$$

Maximum and minimum charge of an ESS [p.u.] «*eMaxCharge*» «*eMinCharge*»

$$\frac{c^p_{\omega ne} + dr'^p_{\omega ne}}{\overline{GC}^p_{\omega ne} - GC^p_{\omega ne}} \leq 1 \quad \forall p\omega ne$$

$$c^p_{\omega ne} - ur'^p_{\omega ne} \geq 0 \quad \forall p\omega ne$$

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Incompatibility between charge and discharge of an ESS [p.u.] «*eChargeDischarge*»

$$\frac{p^{p}_{\omega ne} + URA\ ur'^{p}_{\omega ne}}{\overline{GP}^{p}_{\omega ne} - GP^{p}_{\omega ne}} + \frac{c^{p}_{\omega ne} + DRA\ dr'^{p}_{\omega ne}}{\overline{GC}^{p}_{\omega ne} - GC^{p}_{\omega ne}} \leq 1 \quad \forall p\omega ne, e \in EE, CE$$

Total output of a committed unit (all except the VRES units) [GW] «*eTotalOutput*»

$$\frac{gp^{p}_{\omega ng}}{GP^{p}_{\omega ng}} = uc^{p}_{\omega ng} + \frac{p^{p}_{\omega ng} + URA\ ur^{p}_{\omega ng} - DRA\ dr^{p}_{\omega ng}}{GP^{p}_{\omega ng}} \quad \forall p\omega ng$$

Total charge of an ESS [GW] «*eESSTotalCharge*»

$$\frac{gc^{p}_{\omega ne}}{GC^{p}_{\omega ne}} = 1 + \frac{c^{p}_{\omega ne} + URA\ ur'^{p}_{\omega ne} - DRA\ dr'^{p}_{\omega ne}}{GC^{p}_{\omega ne}} \quad \forall p\omega ne, e \in EE, CE$$

Incompatibility between charge and outflows use of an ESS [p.u.] «*eChargeOutflows*»

$$\frac{go^{p}_{\omega ne} + c^{p}_{\omega ne}}{\overline{GC}^{p}_{\omega ne} - GC^{p}_{\omega ne}} \leq 1 \quad \forall p\omega ne, e \in EE, CE$$

Logical relation between commitment, startup and shutdown status of a committed unit (all except the VRES units) [p.u.] «*eUCStrShut*»

$$uc^{p}_{\omega ng} - uc^{p}_{\omega, n-v, g} = su^{p}_{\omega ng} - sd^{p}_{\omega ng} \quad \forall p\omega ng$$

Maximum commitment of a committable unit (all except the VRES units) [p.u.] «*eMaxCommitment*»

$$uc^{p}_{\omega ng} \leq uc'_{g} \quad \forall p\omega ng$$

Maximum commitment of any unit [p.u.] «*eMaxCommitGen*»

$$\sum_{p\omega n} \frac{gp^{p}_{\omega ng}}{\overline{GP}_{g}} \leq uc'_{g} \quad \forall p\omega ng$$

Mutually exclusive g and g' units (e.g., thermal, ESS, VRES units) [p.u.] «*eExclusiveGens*»

$$uc'_{g} + uc'_{g'} \leq 1 \quad \forall g, g'$$

Initial commitment of the units is determined by the model based on the merit order loading, including the VRES and ESS units.

Maximum ramp up and ramp down for the second block of a non-renewable (thermal, hydro) unit [p.u.] «*eRampUp*» «*eRampDw*»

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P. Damcı-Kurt, S. Küçükyavuz, D. Rajan, and A. Atamtürk, “A polyhedral study of production ramping,” Math. Program., vol. 158, no. 1–2, pp. 175–205, Jul. 2016. 10.1007/s10107-015-0919-9

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$$\frac{-p^{p}_{\omega,n-\nu,g} - dr^{p}_{\omega,n-\nu,g} + p^{p}_{\omega ng} + ur^{p}_{\omega ng}}{DUR^{p}_{\omega n} RU_{g}} \leq uc^{p}_{\omega ng} - su^{p}_{\omega ng} \quad \forall p\omega ng$$

$$\frac{-p^{p}_{\omega,n-\nu,g} + ur^{p}_{\omega,n-\nu,g} + p^{p}_{\omega ng} - dr^{p}_{\omega ng}}{DUR^{p}_{\omega n} RD_{g}} \geq -uc^{p}_{\omega,n-\nu,g} + sd^{p}_{\omega ng} \quad \forall p\omega ng$$

Maximum ramp down and ramp up for the charge of an ESS [p.u.] «*eRampUpCharge*» «*eRampDwCharge*»

$$\frac{-c^{p}_{\omega,n-\nu,e} - ur^{p}_{\omega,n-\nu,e} + c^{p}_{\omega ne} + dr^{p}_{\omega ne}}{DUR^{p}_{\omega n} RD_{e}} \leq 1 \quad \forall p\omega ne$$

$$\frac{-c^{p}_{\omega,n-\nu,e} + dr^{p}_{\omega,n-\nu,e} + c^{p}_{\omega ne} - ur^{p}_{\omega ne}}{DUR^{p}_{\omega n} RU_{e}} \geq -1 \quad \forall p\omega ne$$

Minimum up time and down time of thermal unit [h] «*eMinUpTime*» «*eMinDownTime*»

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D. Rajan and S. Takriti, “Minimum up/down polytopes of the unit commitment problem with start-up costs,” IBM, New York, Technical Report RC23628, 2005. https://pdfs.semanticscholar.org/b886/42e36b414d5929fed48593d0ac46ae3e2070.pdf

$$\sum_{n'=n+\nu-TU_{t}}^{n} s\, u^{p}_{\omega n' t} \leq uc^{p}_{\omega nt} \quad \forall p\omega nt$$

$$\sum_{n'=n+\nu-TD_{t}}^{n} s\, d^{p}_{\omega n' t} \leq 1 - uc^{p}_{\omega nt} \quad \forall p\omega nt$$

Reservoir operation

Maximum and minimum relative volume of reservoir candidates (only for load levels multiple of 1, 24, 168, 8736 h depending on the reservoir volume type) constrained by the hydro commitment decision times the maximum capacity [p.u.] «*eMaxVolume2Comm*» «*eMinVolume2Comm*»

$$\frac{i'^{p}_{\omega ne'}}{\overline{I'}^{p}_{\omega ne'}} \leq \sum_{h \in dw(e')} u\, c^{p}_{\omega nh} \quad \forall p\omega ne', e' \in CR$$

$$\frac{i'^{p}_{\omega ne'}}{I'^{\,p}_{\omega ne'}} \geq \sum_{h \in dw(e')} u\, c^{p}_{\omega nh} \quad \forall p\omega ne', e' \in CR$$

Operating reserves from a hydropower plant can only be provided if enough energy is available for turbining at the upstream reservoir [GW] «*eTrbReserveUpIfEnergy*» «*eTrbReserveDwIfEnergy*»

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$$ur^{p}_{\omega nh} \leq \frac{\sum_{e' \in up(h)} i'^{p}_{\omega ne'}}{DUR^{p}_{\omega n}} \quad \forall p \omega n h$$

$$dr^{p}_{\omega nh} \leq \frac{\sum_{e' \in up(h)} \overline{I'}^{p}_{\omega ne'} - i'^{p}_{\omega ne'}}{DUR^{p}_{\omega n}} \quad \forall p \omega n h$$

or for pumping [GW] «*ePmpReserveUpIfEnergy*» «*ePmpReserveDwIfEnergy*»

$$ur'^{p}_{\omega nh} \leq \frac{\sum_{e' \in up(h)} \overline{I'}^{p}_{\omega ne'} - i'^{p}_{\omega ne'}}{DUR^{p}_{\omega n}} \quad \forall p \omega n h$$

$$dr'^{p}_{\omega nh} \leq \frac{\sum_{e' \in up(h)} i'^{p}_{\omega ne'}}{DUR^{p}_{\omega n}} \quad \forall p \omega n h$$

Water volume for each hydro reservoir (only for load levels multiple of 1, 24, 168 h depending on the reservoir storage type) [hm^3] «*eHydroInventory*»

$$i'^{p}_{\omega,n-\frac{\tau_{e'}}{\nu,e'}} + \sum_{n'=n-\frac{\tau_{e'}}{\nu}}^{n} DUR^{p}_{\omega n'} (0.0036 HI^{p}_{\omega n'e'} - 0.0036 ho^{p}_{\omega n'e'} - \sum_{h \in dw(e')} g\, p^{p}_{\omega n'h}/PF_h + \sum_{h \in up(e')} g\, p^{p}_{\omega n'h}/PF_h + + \sum_{h \in up(e')} E\, F_{e'} gc^{p}_{\omega n'h}/PF_h - \sum_{h \in dw(h)} E\, F_{e'} gc^{p}_{\omega n'h}/PF_h) = i'^{p}_{\omega ne'} + s'^{p}_{\omega ne'} - \sum_{e'' \in up(e')} s'^{p}_{\omega ne''} \quad \forall p \omega n e', e' \in ER$$

$$i'^{p}_{\omega,n-\frac{\tau_{e'}}{\nu,e'}} + \sum_{n'=n-\frac{\tau_{e'}}{\nu}}^{n} DUR^{p}_{\omega n'} (0.0036 hi^{p}_{\omega n'e'} - 0.0036 ho^{p}_{\omega n'e'} - \sum_{h \in dw(e')} g\, p^{p}_{\omega n'h}/PF_h + \sum_{h \in up(e')} g\, p^{p}_{\omega n'h}/PF_h + + \sum_{h \in up(e')} E\, F_{e'} gc^{p}_{\omega n'h}/PF_h - \sum_{h \in dw(h)} E\, F_{e'} gc^{p}_{\omega n'h}/PF_h) = i'^{p}_{\omega ne'} + s'^{p}_{\omega ne'} - \sum_{e'' \in up(e')} s'^{p}_{\omega ne''} \quad \forall p \omega n e', e' \in CR$$

The initial volume of the hydro reservoir divided by its initial volume $I^{p}_{\omega e'}$ is equal to the final reservoir divide by its initial volume [p.u.] «*eIniFinVolume*».

$$\frac{i'^{p}_{\omega,0,e'}}{I^{p}_{\omega e'}} = \frac{i'^{p}_{\omega,N,e'}}{I^{p}_{\omega e'}} \quad \forall p \omega e', e' \in CE$$

Hydro outflows (only for load levels multiple of 1, 24, 168, 672, and 8736 h depending on the ESS outflow cycle) must be satisfied [m^3/s] «*eHydroOutflows*»

$$\sum_{n'=n-\frac{\tau_{e'}}{\rho_{e'}}}^{n} \left(ho^{p}_{\omega n'e'} - HO^{p}_{\omega n'e'}\right) DUR^{p}_{\omega n'} = 0 \quad \forall p \omega n e', n \in \rho'_{e}$$

Electricity network operation

Logical relation between transmission investment and switching {0,1} «*eLineStateCand*»

$$swt^{p}_{\omega nijc} \leq ict^{p}_{ijc} \quad \forall p \omega n ijc, ijc \in CL$$

Logical relation between switching state, switch-on and switch-off status of a line [p.u.] «*eSWOnOff*»

$$swt^{p}_{\omega nijc} - swt^{p}_{\omega,n-\nu,ijc} = son^{p}_{\omega nijc} - sof^{p}_{\omega nijc} \quad \forall p \omega n ijc$$

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The initial status of the lines is pre-defined as switched on.

Minimum switch-on and switch-off state of a line [h] «*eMinSwOnState*» «*eMinSwOffState*»

$$\sum_{n'=n+v-SON_{ijc}}^{n} son^{p}_{\omega n' ijc} \leq swt^{p}_{\omega nijc} \quad \forall p\omega nijc$$

$$\sum_{n'=n+v-SOF_{ijc}}^{n} sof^{p}_{\omega n' ijc} \leq 1 - swt^{p}_{\omega nijc} \quad \forall p\omega nijc$$

Flow limit in transmission lines [p.u.] «*eNetCapacity1*» «*eNetCapacity2*»

$$-swt^{p}_{\omega nijc} \leq \frac{f^{p}_{\omega nijc}}{\overline{F}_{ijc}} \leq swt^{p}_{\omega nijc} \quad \forall p\omega nijc$$

DC Power flow for existing and non-switchable, and candidate and switchable AC-type lines (Kirchhoff's second law) [rad] «*eKirchhoff2ndLaw1*» «*eKirchhoff2ndLaw2*»

$$\frac{f^{p}_{\omega nijc}}{\overline{F}'_{ijc}} - \left(\theta^{p}_{\omega ni} - \theta^{p}_{\omega nj}\right)\frac{S_B}{X_{ijc}\overline{F}'_{ijc}} = 0 \quad \forall p\omega nijc, ijc \in EL$$

$$-1 + swt^{p}_{\omega nijc} \leq \frac{f^{p}_{\omega nijc}}{\overline{F}'_{ijc}} - \left(\theta^{p}_{\omega ni} - \theta^{p}_{\omega nj}\right)\frac{S_B}{X_{ijc}\overline{F}'_{ijc}} \leq 1 - swt^{p}_{\omega nijc} \quad \forall p\omega nijc, ijc \in CL$$

Half ohmic losses are linearly approximated as a function of the flow [GW] «*eLineLosses1*» «*eLineLosses2*»

$$-\frac{L_{ijc}}{2} f^{p}_{\omega nijc} \leq l^{p}_{\omega nijc} \geq \frac{L_{ijc}}{2} f^{p}_{\omega nijc} \quad \forall p\omega nijc$$

Cycle constraints for AC existing lines with DC power flow formulation [rad] «*eCycleKirchhoff2ndLawCnd1*» «*eCycleKirchhoff2ndLawCnd2*». See the cycle constraints for the AC power flow formulation in the following reference:

- E.F. Álvarez, J.C. López, L. Olmos, A. Ramos "An Optimal Expansion Planning of Power Systems Considering Cycle-Based AC Optimal Power Flow" Sustainable Energy, Grids and Networks, May 2024. 10.1016/j.segan.2024.101413

Kirchhoff's second law is substituted by a cycle flow formulation for cycles with only AC existing lines [rad]

$$\sum_{ijc \in cy} f_{\omega pnijc} \frac{X_{ijc}}{S_B} = 0 \quad \forall \omega pn, cy, cy \in CY$$

and disjunctive constraints for cycles with some AC candidate line [rad]

$$-1 + ict_{i'j'c'} \leq \frac{\sum_{ijc \in cy} f_{\omega pnijc} \frac{X_{ijc}}{S_B}}{\overline{\theta}'_{cy,i'j'c'}} \leq 1 - ict_{i'j'c'} \quad \forall \omega pn, cy, i'j'c', cy \in CY, i'j'c' \in CLC$$

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Flows in AC existing parallel circuits are inversely proportional to their reactances [GW] «*eFlowParallelCandidate1*» «*eFlowParallelCandidate2*»

$$f_{\omega pnijc} = \frac{X_{ijc'}}{X_{ijc}} f_{\omega pnijc'} \quad \forall \omega pnijcc', ijc \in EL, ijc' \in EL$$

and disjunctive constraints in AC candidate parallel circuits are inversely proportional to their reactances [p.u.]

$$-1 + ict_{ijc'} \leq \frac{f_{\omega pnijc} - \frac{X_{ijc'}}{X_{ijc}} f_{\omega pnijc'}}{\overline{F}_{ijc}} \leq 1 - ict_{ijc'} \quad \forall \omega pnijcc', ijc \in EL, ijc' \in CL$$

Given that there are disjunctive constraints, which are only correct with binary AC investment variables, this cycle-based formulation must be used only with binary AC investment decisions.

Hydrogen network operation

Balance of hydrogen generation by electrolyzers, hydrogen consumption from hydrogen heater using it, and demand at each node [tH2] «*eBalanceH2*»

$$\sum_{e \in i} \frac{DUR^p_{\omega n}}{PF'_e} gc^p_{\omega ne} - \sum_{g \in i} g\, h^p_{\omega ng} + hns^p_{\omega ni} = DUR^p_{\omega n} DH^p_{\omega ni} + \sum_{jc} f\, h^p_{\omega nijc} - \sum_{jc} f\, h^p_{\omega njic} \quad \forall p\omega ni$$

Heat network operation

Balance of heat generation produced by CHPs and fuel heaters respectively and demand at each node [GW] «*eBalanceHeat*»

$$\sum_{e \in i} \frac{DUR^p_{\omega n}}{PF''_e} gc^p_{\omega ne} + \sum_{g \in i} g\, h^p_{\omega ng} + htns^p_{\omega ni} = DUR^p_{\omega n} DF^p_{\omega ni} + \sum_{jc} f\, p^p_{\omega nijc} - \sum_{jc} f\, p^p_{\omega njic} \quad \forall p\omega ni$$

Bounds on generation and ESS variables [GW]

$$0 \leq gp^p_{\omega ng} \leq \overline{GP}^p_{\omega ng} \quad \forall p\omega ng$$

$$0 \leq go^p_{\omega ne} \leq \max\left(\overline{GP}^p_{\omega ne}, \overline{GC}^p_{\omega ne}\right) \quad \forall p\omega ne$$

$$0 \leq gc^p_{\omega ne} \leq \overline{GC}^p_{\omega ne} \quad \forall p\omega ne$$

$$GH^p_{\omega ng} \leq gh^p_{\omega ng} \leq \overline{GH}^p_{\omega ng} \quad \forall p\omega ng$$

$$0 \leq ur^p_{\omega ng} \leq \overline{GP}^p_{\omega ng} - GP^p_{\omega ng} \quad \forall p\omega ng$$

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$$0 \leq ur'^{p}_{\omega ne} \leq \overline{GC}^{p}_{\omega ne} - GC^{p}_{\omega ne} \quad \forall p\omega ne$$

$$0 \leq dr^{p}_{\omega ng} \leq \overline{GP}^{p}_{\omega ng} - GP^{p}_{\omega ng} \quad \forall p\omega ng$$

$$0 \leq dr'^{p}_{\omega ne} \leq \overline{GC}^{p}_{\omega ne} - GC^{p}_{\omega ne} \quad \forall p\omega ne$$

$$0 \leq p^{p}_{\omega ng} \leq \overline{GP}^{p}_{\omega ng} - GP^{p}_{\omega ng} \quad \forall p\omega ng$$

$$0 \leq c^{p}_{\omega ne} \leq \overline{GC}^{p}_{\omega ne} \quad \forall p\omega ne$$

$$I^{p}_{\omega ne} \leq i^{p}_{\omega ne} \leq \overline{I}^{p}_{\omega ne} \quad \forall p\omega ne$$

$$0 \leq s^{p}_{\omega ne} \quad \forall p\omega ne$$

$$0 \leq ens^{p}_{\omega ni} \leq D^{p}_{\omega ni} \quad \forall p\omega ni$$

Bounds on reservoir variables [m³/s, hm³]

$$0 \leq ho^{p}_{\omega ne'} \leq \sum_{h \in dw(e')} \overline{GP}^{p}_{\omega nh} / PF_{h} \quad \forall p\omega ne'$$

$$I'^{p}_{\omega ne'} \leq i'^{p}_{\omega ne'} \leq \overline{I'}^{p}_{\omega ne'} \quad \forall p\omega ne'$$

$$0 \leq s'^{p}_{\omega ne'} \quad \forall p\omega ne'$$

Bounds on electricity network variables [GW]

$$0 \leq l^{p}_{\omega nijc} \leq \frac{L_{ijc}}{2} \overline{F}_{ijc} \quad \forall p\omega nijc$$

$$-\overline{F}_{ijc} \leq f^{p}_{\omega nijc} \leq \overline{F}_{ijc} \quad \forall p\omega nijc, ijc \in EL$$

Voltage angle of the reference node fixed to 0 for each scenario, period, and load level [rad]

$$\theta^{p}_{\omega n, node_{ref}} = 0$$

Bounds on hydrogen network variables [tH2]

$$-\overline{FH}_{ijc} \leq fh^{p}_{\omega nijc} \leq \overline{FH}_{ijc} \quad \forall p\omega nijc, ijc \in EP$$

Bounds on heat network variables [GW]

$$-\overline{FP}_{ijc} \leq fp^{p}_{\omega nijc} \leq \overline{FP}_{ijc} \quad \forall p\omega nijc, ijc \in EP$$

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