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DECARBONISATION THROUGH INNOVATION

"The role of large-scale heat pumps in the future Finnish energy system"

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Abstract

The extensive integration of renewable resources into power grids and power-to-heat technologies facilitates sector coupling and accelerates the decarbonization of the energy sector. This study investigates the introduction of large-scale heat pumps (HPs) into Finland's national power and district heating (DH) networks. The research conducts an analytical and optimization study using actual hourly generation data from 2023 and models the energy system for 2030 with projected capacity development and a focus on the significance of HP and the heat generation side. The energy system is modeled and evaluated using the Calliope and EnergyPLAN frameworks across several future scenarios. The costs and capacity of power and heat generation technologies, storage technologies, cross-border electricity import and export, DH, electricity consumption, power curtailment, and fuel use are investigated. Findings show that increasing the capacity of the HPs will reduce the biomass fuel use of the system by 9.1% by 2030 as the total wind and solar capacities are raised simultaneously. Furthermore, the development of power generation capacity significantly influences the system's cost savings. While HP and thermal energy storage (TES) can help to reduce excess electricity generation, sufficient dispatchable generation capacity or electricity storage must be maintained in the power system, which cannot be reduced with TES alone. It can be concluded that Finland can take decisive steps to the electrification of its heating networks by applying renewables and HP technologies, reaching up to 78% and 37% share of HP generation in DH networks without and with cogeneration technologies. This study offers an estimation of future production and a dynamic overview of potential shortages, emphasizing the operational limitations that must be resolved to ensure energy reliability and autonomy in the future, along with limitations in the sector coupling of power and heating sectors.

Keywords: *Electrification; District heating; Heat pumps; Optimization; Energy system analysis*

1. Introduction

The Paris Agreement sets the climate goal of restricting the rise in global average temperature to below 2℃ above pre-industrial levels, with an ambitious target of no more than 1.5℃ [1]. The Nordic region leads worldwide initiatives, intending to attain carbon neutrality in the following decades [2]. Finland aims to achieve carbon neutrality by 2035 [3]. The energy sector in Finland constitutes around 70% of the nation's total greenhouse gas emissions, which makes it the primary source of emissions [4]. Comprehensive decarbonization policies are essential for reaching emission reduction targets. The IEA's decarbonization strategies emphasize critical components such as expanding renewable energy, enhancing energy efficiency, electrifying different sectors, implementing carbon capture technology, and boosting hydrogen-based fuels [5].

Electrification is a practical means of decarbonizing energy sectors that are currently reliant on combustion technologies, largely powered by fossil fuels. The current surge in clean electricity production technologies is primarily driven by wind power and solar photovoltaics (PV) [5]. According to Fingrid, electricity production

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in Finland may grow from 83 TWh in 2025 to more than 120 TWh in 2030, fully due to the increase of wind and PV production [6].

Sector coupling is another promising strategy for enhancing the integration of renewable energy [7]. Heating energy has a high demand in the cold climate of the Nordics, demonstrating significant potential for decarbonization. In 2022, heating the buildings accounted for 27.1% of the final energy consumption in Finland [8]. Sector coupling can help decarbonize district heating (DH) networks and increase the use of renewable energy. The flexible utilization of renewable electricity for heating facilitates the decarbonization of the heating sector and enhances the integration of variable renewable energies (VREs) into the power grid by offering higher adaptability [9]. Electricity consumption for space heating in Finland is forecast to increase by about nine terawatt hours, which is boosted especially by electric DH [6]. An effective approach for a future low-carbon heating market involves energy-efficient buildings equipped with thermal energy storage (TES) systems integrated with electrified low-carbon technologies like heat pumps (HPs) [10].

Some regional and national surveys provide simulations and analyses for renewable energy development in power or heat sectors. Lizana et al. [11] examined the necessary heat storage capacity in buildings in Spain and the UK to mitigate peak power demand and optimize carbon reductions related to electrified heating systems via smart demand-side response. An Italian case study on decarbonization [12] investigated heating, industry, transportation, energy efficiency in buildings, flexibility, storage, and renewable energy generation, concluding that around 90% of energy might be produced by VRE. Although comprehensive, the study excluded nuclear power and did not present the required reserve power capacity. A thorough analysis of a fully renewable energy system in Finland, comprising electricity, electric vehicles (EVs), and DH, was conducted in [13] and [14]. Despite assessing many sectors, they employed generic figures for flexible electricity demand (e.g., 1.5 GW and 2 TWh yearly) that could be adjusted within 24 hours; nevertheless, EV driving patterns were overlooked, and peak reserve power was not evaluated. Jokinen et al. [15] analyzed the electrification of DH, building stock, and passenger vehicle transport, alongside the increased contributions of solar PV, wind, and nuclear energy in power generation. However, they did not consider the electricity grid, its integration into the power system, and the cross-border import and export of power. Kankanamge et al. [16] studied the economic viability of large-scale solar PV deployment in Finland and concluded that, given the current solar PV outlook, the integration of many additional gigawatts of PV in Finland necessitates optimized EV charging and DH electrification. An optimization study for the integration of power-to-heat (PtH) technologies in the district energy systems of Turku, Finland, demonstrated that HPs and high-temperature HPs could adequately meet the annual demands of DH and steam networks, respectively, while the requirement for electricity production rose from 236 GWh to 327 GWh [17].

Schroderus et al. [18] analyzed the power production and consumption patterns in Finland for 2023 and studied the projected data from Fingrid, the Finnish transmission system operator, for 2030. They estimated that Finland will be electricity-negative for 61% of the hours in 2030, with an annual deficit of 10 TWh. Su et al. [19] analyzed the decarbonization strategies of DH companies in the Helsinki metropolitan area concerning CO_2 emissions and production costs. It was determined that from 2010 to 2030, CO_2 emissions from the DH of the region will decrease by about 4.2 million tonnes, while the average heat production costs will likely rise significantly, nearly tripling. Javanshir et al. [20] studied the optimization of revenues from operating the DH networks in the day-ahead and intraday electricity markets, in addition to offering balancing services via PtH units in Finland. Salpakari et al. [21] presented optimal control models for studying the economic and technical potential of PtH conversion and load shifting for PV and wind integration in Helsinki. Through optimal load-VRE alignment, PtH efficiently utilizes excess VRE beyond the self-consumption limits, achieving a 35% reduction in surplus without the need for storage at peak VRE levels. To support decarbonization and electrification of the DH infrastructures of the city of Kuopio in Eastern Finland, [22] employed building energy renovation programs and used wind electricity at a fixed price rather than the market price for the deployed PtH technologies. They concluded that abandoning peat is possible with a decreased electricity tax, a higher carbon cost, energy renovation of buildings, and a low-temperature DH network.

The studies mentioned highlight significant trends of electrification and sector coupling through VRE deployment and HPs while providing projections for renewable energy development in specific regions, considering limited technologies for power generation, or examining the power grid and DH network separately. However, in the long term, the decarbonization of heat via electrification must be integrated with the effective decarbonization of the power grid [23], which makes it more complicated and challenging. Few studies offer high-resolution optimization analyses comparing real-world hourly patterns for Finland's electricity and heating markets and providing future cost and capacity estimates. Our work will further this pattern by examining the Finnish energy system at a national scale, where a significant proportion of renewable electricity will replace the current power generation technologies and fuel HPs to produce thermal energy for

DH networks. There is also a major look at the role of TES technology as the key enabler for the integration of power and heat sectors. This research helps to gain knowledge about Finland's potential for extensive VRE deployment, together with insights into the costs and capacity of its heating networks in replacing conventional heat generation units by large-scale HPs. The following is the contribution of this study:

- Collecting data and modelling the current heat and power energy systems of Finland at a country level.
- Considering the temporal variability and operational challenges at an hourly resolution rather than average capacity factors or aggregated annual values associated with different generating technologies across both sectors.
- Using two distinct frameworks, Calliope and EnergyPLAN, for energy system modelling and optimization, enabling a comparison of outcomes and an assessment of the sensitivity of findings to the type of tool employed.
- Feasibility assessment and checking the adequacy of future capacity projections for the Finnish energy authorities, particularly for wind and solar.
- Investigating the Finnish energy system by 2030, highlighting the role of HP and TES in sector coupling.
- Studying the future energy dependence of Finland on its neighboring countries and international networks by analyzing the import and export of power across borders.

Section 2 of this paper describes the energy system model. Section 3 addresses tools, equations, input data and assumptions, prospective scenarios, and methodology. Section 4 presents the results of the modelling, optimization, and sensitivity studies. Section 5 sets out the conclusions.

2. System description

This research considers wind power, solar energy, hydropower, biomass, industrial combined heat and power (CHP) plants, condensing power plants (CPPs), and nuclear energy as sources of power. Moreover, a CHP unit produces power and heat using waste. A power shortage may necessitate imports, whereas any surplus power can be exported, with a limited export/import capacity. In future scenarios, where wind and solar capacity is expected to reach the levels projected by Fingrid, an additional power storage system may be necessary; therefore, this technology is also considered. Hydropower also acts as a storage element in the current power system.

Other heat generation technologies include heat-only boilers (HOBs), HPs, and electric boilers (EBs). Furthermore, there is a limited amount of heat recovery from the industrial sectors. In the reference model, the CPP, CHP, and HOB are fueled by the typical fuel mix used in Finland in 2023, whereas in future scenarios, they use biomass. We also consider TES technology as the key enabler of integrating the power and heat sectors. Fig. 1 shows the energy system model under investigation in this study, which focuses on power demand and DH demand. This paper excludes industrial heat demand and district cooling.

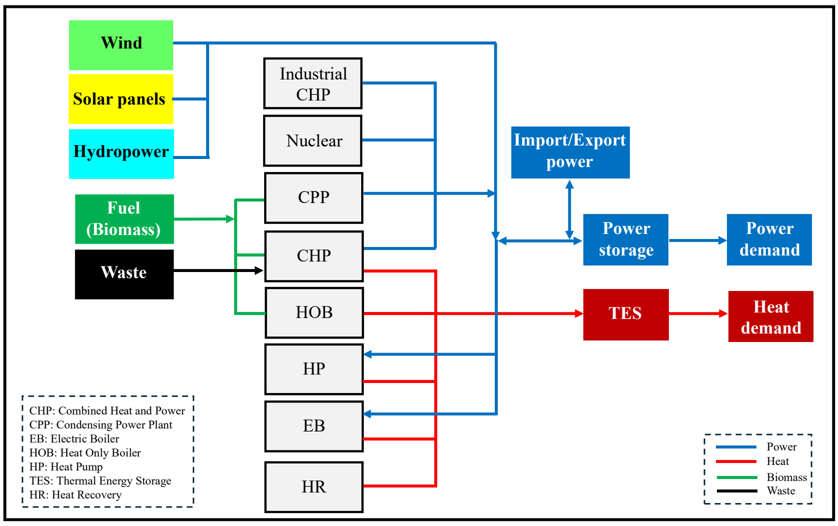


Figure 1. Illustration of the studied system.

3. Modelling

The tools and equations used for modelling and optimization in this study are explained in this section. Next, the technical data and assumptions regarding the power and heat energy carriers are elaborated. Then the future scenarios are explained in detail. Finally, the methodology used in this study is illustrated.

3.1. Tools

An hourly mass and energy balance model has been constructed using EnergyPLAN software and the Calliope framework. Notwithstanding their distinct analytical capabilities, both tools operate effectively for their designated functions when utilized separately. EnergyPLAN is a user-friendly and established simulation program with confined optimization capabilities, whereas Calliope requires more user inputs yet operates as an optimization tool. EnergyPLAN is a deterministic model that facilitates the development of national or regional energy planning strategies through technical and economic evaluations of the implications of various energy systems and investments [24]. The model includes the entire national or regional energy system, encompassing heat and power suppliers, along with the transportation and industrial sectors.

Calliope facilitates node-based energy system modeling, employing linear and mixed-integer linear programming techniques for the optimization of unit capacities and operation. A variety of solvers are available, including GLPK, CBC, Gurobi, and CPLEX. For additional information concerning the Calliope, please refer to [25].

The simulation model in EnergyPLAN is built around the electrical and district heating sectors, discarding other sectors outside the scope of this study, such as transport and individual heating. A technical simulation strategy is used, balancing both electricity and heating demand, with regulation strategy 59. Regulation strategy limits the overproduction of electricity by first replacing HOB with EB and secondly part-loading nuclear power plants.

Calliope provides more levels of freedom in the problem statement, but the approach was selected so that the comparability of results between the modeling frameworks is retained. Capacities on the electricity production side are fixed to the values stated in the technical details and scenario definitions, while the heat production side capacities between competing technologies are set as decision variables to be optimized. These include the capacities of EB, HP, HOB, and TES. To gain understanding of the required battery energy storage system (BESS) capacity, this is also set as an optimization decision variable. The dispatchment of each technology at each timestep is a decision variable for the optimization algorithm. The objective function of the optimization method is to minimize the total monetary costs of the system, including annualized investment costs and the variable and fixed operation costs. Main boundary conditions include the mandatory fulfillment of heating and electricity demand.

3.2. Equations

Given the diverse technologies present in each energy system model, it is essential to conduct a thorough evaluation of the economic characteristics associated with these system technologies. This paper investigates the total cost of the system, which includes the investment costs, variable and fixed operation and maintenance costs (OPEX), fuel costs, and electricity exchange costs. The same concept is utilized in EnergyPLAN as socio-economic costs [24]. Therefore, the costs were determined as annualized costs for a single year by using Eq. (1):

$$cost = CRF \cdot CAPEX + fixed\ OPEX + variable\ OPEX \tag{1}$$

In Eq. (1), *variable OPEX* encompasses fuel expenses alongside the expenditures associated with imported or exported power, and CRF, the capital recovery factor, converts the total investment cost into annual costs, affected by the interest rate (i) and the technology lifetime (n) as presented in Eq. (2) [26]

$$CRF = \frac{i\,(1+i)^n}{(1+i)^n - 1} \tag{2}$$

Critical excess electricity production (CEEP) is another parameter that we investigate in this study. EnergyPLAN describes exports as two types: CEEP and exportable excess electricity production, EEEP. CEEP appears when the export exceeds the maximum capacities of the grid connections abroad [24]:

$$\begin{cases} if\ P_{Export} > P_{max,transmission} \\ E_{CEEP} = [P_{export} - P_{max,transmission}] \cdot t_{timestep} \quad and\ E_{EEEP} = P_{max,transmission} \cdot t_{timestep} \\ else \\ E_{CEEP} = 0 \quad and \quad E_{EEEP} = P_{export} \cdot t_{timestep} \end{cases} \tag{3}$$

where E_{CEEP} is the hourly critical excess electricity production, P_{Export} is the hourly excess electrical power, $P_{max,transmission}$ is the maximum electricity export capacity, and $t_{timestep}$ is the timestep length, 1 h. Calliope does not have a concept for CEEP, as the overproduction of electricity is avoided by part-loading the production technologies. As a comparison, VRE curtailment is used as an indication of CEEP in Calliope. VRE curtailment is calculated by:

$$\begin{cases} if\ P_{VRE} < P_{resource} \\ E_{curtailment} = [P_{resource} - P_{VRE}] \cdot t_{timestep} \\ else \\ E_{curtailment} = 0 \end{cases} \tag{4}$$

$P_{resource}$ is the VRE resource available, and P_{VRE} is the actual VRE production at each timestep and $E_{curtailment}$ is the curtailed VRE production.

3.3. Technical data

This study used the statistics from the Finnish energy market data in 2023 regarding supply, demand, and energy carriers for the electricity and heating domains. The hourly data on power production from different electricity generation technologies, along with imported and exported electricity, and the hourly rates of electricity consumption, are gathered from TSO data [27]. The capacities of power generation technologies are based on the Power Plant Registry [28] and TSO hourly maximum values [27]. DH statistics are used for heat generation and demand [29]. Table 1 delineates the power and heat generation units together with their respective capacities within current Finnish energy infrastructure and this research. It is noteworthy that [28] excludes residential-scale PV for solar energy and omits small-scale plants in the hydropower segment; therefore, the data is picked from alternative sources. The transmission capacity to neighboring countries was assumed to be symmetrical for export and import, and an average value of 2800 MW is used [27].

DH distribution networks are categorized between those without CHP systems, referred to as group 2 (G2), and those with CHP systems, designated as group 3 (G3). This classification facilitates the consideration of smaller DH networks in Finland that do not incorporate CHP technology and follows the grouping used in EnergyPLAN. Furthermore, G3 included the limited capacity of currently installed EBs and HPs. Finnish authorities' data indicates that in 2023, DH networks received 36.7 TWh of thermal energy, with approximately 9.5% resulting in losses. For the CHP system, total, thermal, and electrical efficiency are 83%, 23%, and 60%, respectively, based on the annual average from DH statistics [29]. The coefficient of performance (COP) for the HPs is based on both high-temperature HPs, with low COPs of around 2.5 at high, 70 K temperature lift [30], and on lower sink temperature HPs with a COP of around 4.0 [22]. The temperatures in typical DH networks enter the high-temperature HP region during wintertime; however, the COP also strongly depends on the heat source temperature, which can vary significantly between air source, ground source, sewage, and waste heat applications. Therefore, a COP of 3.0 is used; the value used represents an average between many different types of HPs. The efficiencies used for HOB, CPP, and nuclear power were 90% [31], 40% [32], and 33% [33], respectively.

Table 1. Power and thermal capacity of each technology in the Finnish energy sector and input data in this study

Electricity production							
References	Solar	Hydro	Nuclear	Wind	CPP	CHP	Industrial CHP
Power plant registry (MW_e) [28]	35	2009	4369	5580	1673	1408	2017
TSO data hourly maximum (MW_e) [27]	650	2577	4407	5551	839	2460	1682
Present study (MW_e)	606	3111	4369	5580	1500	2300, 134 (waste)	1470

Thermal energy production						
Group	References	HOB	HR	CHP	HP	EB
G2	Energy (TWh) [29]	5.17	0.75	-	-	-
	Capacity (MW_{th}) [29]	6501	165	-	-	-
	Present study Capacity (MW_{th})	6201	165	-	-	-
G3	Energy (TWh) [29]	9.07	4.57	15.52	0.93	0.73
	Capacity (MW_{th}) [29]	9412	787	6392	-	-
	Present study Capacity (MW_{th})	9412	787	6392	225	200

Table 2 provides data regarding the fuel mix currently used in Finland [29], emissions factors [34], fuel price [35], and the fuel mixture utilized in this study. In EnergyPLAN, peat is included in the coal by calculating the weighted average between the coal and peat price and emissions factors, and waste is given as a separate input.

Table 2. Data about the current fuel mixture in Finland and data used in this study

Fuel	Coal	Oil	Peat *	Gas	Nuclear fuel	Waste	Biomass
Emission factor (kg/GJ) [34]	99.9	69.4	-	55.4	0	31.8	0
Fuel price (€/GJ) [35]	8.3	32.3	5.9	18.3	1.5	0	8.6
Fuel mix in Finland in 2023 (%) [29]	11.5	2.7	10.1	7.1	-	11.9	56.3
Fuel mix in this study (%)	24.6	3.1	-	8.1	-	5140 GWh/a	64.2

3.4. Economic data

Table 3 presents the detailed CAPEX, specific fixed yearly OPEX, and the lifespan of the principal technologies within the planned energy system. Additionally, the interest rate applied to all technologies is 5%, and considering the assumption of natural reservoirs for hydro storage, no cost is designated for hydro storage. The external electricity market price is based on central Sweden prices for 2023, representing an estimated price for the neighboring country with the strongest connection capacities.

Table 3. Economic data for each technology

Technology	Specific CAPEX	Specific annual OPEX (% of CAPEX)	Lifetime	Reference
PV	0.5 M€/MW	1.3	35	[36]
WT	1.3 M€/MW	3.2	25	[36]
Nuclear	6.9 M€/MW	3.5	40	[36]
Hydro power	3.3 M€/MW	1.5	50	[36]
River of hydro	2.8 M€/MW	4	50	[36]
Large power plants	1 M€/MW	2	30	[36]
Large CHP units	0.8 M€/MW	3.7	25	[36]
Waste CHP	215.6 M€/TWh/year	7.4	20	[36]
HP	700 (€/KWth)	1.0	25	[37], [38]
EB	0.17 M€/MW	1.5	20	[39]
HOB	0.1 M€/MW	3.7	35	[36]

Industrial CHP	64.5 M€/TWh/year	2.13	31	[40]
TES	3 M€/GWh	0.7	20	[36]
BESS (4h)	250 M€/GWh	0	20	[41], [42]

3.5. Future scenarios for 2030

After modelling the current Finnish energy system, the electricity and thermal energy networks of Finland in 2030 are studied. The scenarios for 2030 are built based on current projections on the development of the energy system of Finland, including the key assumption of a significant increase in renewable electricity generation in the power sector projected by TSO [6]. The scenarios are aligned with planned upgrades in the current generation portfolio, including upgrades of cross-border transmission capacity. Below is a summary of the key assumptions considered for the future Finnish energy system:

- The capacity of the wind and solar generation is 16 GW of wind power and 6.5 GW of solar, based on the projected capacity in 2030 by TSO [6].
- All fuel consumption for HOB and CHP will be switched to biomass. The waste CHP unit, powered by the constant stream of waste, remains unaffected.
- The electricity demand increases from 78 TWh to 114 TWh following projections in [6]. The increase in electricity consumption for space heating is discarded to avoid the double counting of space heating. The scale-up is done by adding baseload demand to the electricity demand timeseries.
- No changes in DH demand are expected.
- The transmission capacity is assumed to increase 900 MW to a total import/export capacity of 3700 MW based on planned new transmission lines [43].
- The nuclear power capacity is assumed to increase 198 MW according to planned upgrades [44], [45].
- The nuclear generation timeseries account for planned outages around summer (1 month of outage time per nuclear generation unit, Loviisa 1&2 and Olkiluoto 1&2 lumped together).
- Available CPP capacity is increased to 2000 MW due to electrical system requirements and modelling difficulties encountered in EnergyPLAN without this increase.
- Energy storage capacity values are set by the Calliope optimization framework (in SC4-SC6). In EnergyPLAN simulations, the following storage values are used:
  - TES units of 25 GWh and 75 GWh are considered for G2 and G3, respectively.
  - A 4-hour discharge rated BESS with a capacity of 4 GWh.

The different scenarios for 2030 were built by varying the capacities of HPs and TES in the heating sector. SC5 and SC6 test the optimization model in cases where the power generation capacity is more limited. Table 4 shows the scenarios studied for the Finnish energy system in 2030.

Table 4. Scenarios considered for the Finnish energy system in 2030.

Scenario (SC)	Description
SC1 (EnergyPLAN)	No increase in HP capacity ($HP_{cap,G3} = 225\ MW_{th}$), TES 100 GWh
SC2 (EnergyPLAN)	1000 MW_{th} of HP in G2 and G3, TES 100 GWh
SC3 (EnergyPLAN)	1000 MW_{th} of HP in G2 and G3, no TES
SC4 (Calliope)	Optimized heat production and storage capacities
SC5 (Calliope)	Optimized heat production and storage capacities, no CPP allowed
SC6 (Calliope)	Optimized heat production and storage capacities, no CPP and no TES allowed

3.6. Methodology

Fig. 2 demonstrates the workflow employed in this investigation, including data preparation and processing, system definition, modeling and optimization, verification, and sensitivity assessments.

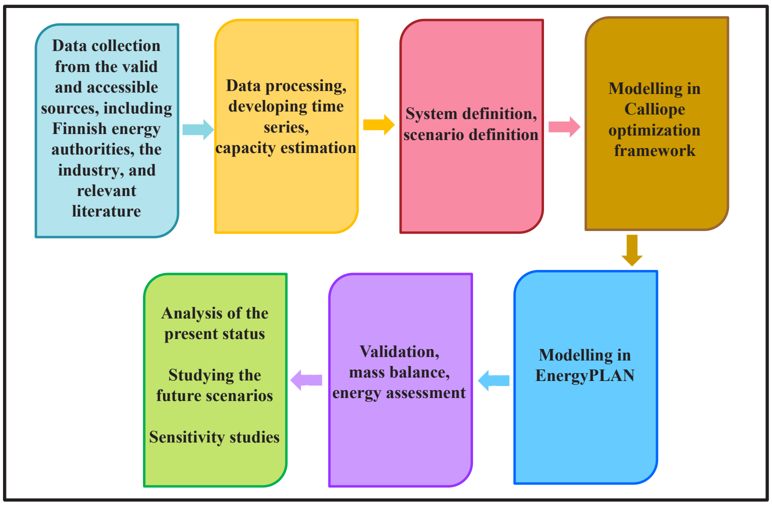


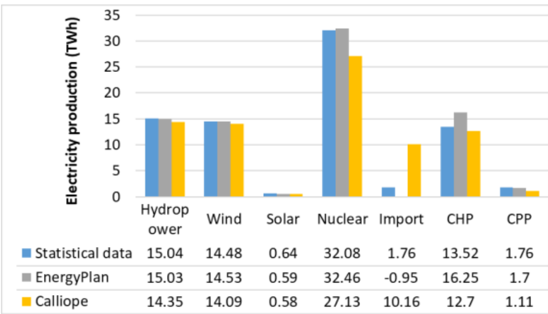
Figure 2. Workflow of this study.

4. Results and discussion

4.1. 2023 reference case

The results of the models are compared to the statistical data provided by Finnish energy authorities for 2023. The results generally match closely with the statistics; the main differences on the electrical side are the part-loading of nuclear power and the amount of imported electricity, as shown in Fig. 3. Calliope prefers to import more electricity and part-load nuclear generation whenever the external electricity price is lower than the fuel costs of nuclear generation.

The DH generation in Fig. 4 shows that the main differences between the model results are the CHP and HOB generation. EnergyPLAN operates CHP plants more than the statistical data shows, and this results in lower HOB generation. Calliope uses less CHP generation and higher HOB generation than statistical data. The differences between statistical and modeling results in CHP generation can be caused by the aggregation approach, which cannot consider all the characteristics of individual DH networks and CHP plants, such as capacity limitations, minimum part load requirements, ramp rate limitations, etc. Additionally, the two modelling approaches diverge in their operation logic—the technical simulation strategy of EnergyPLAN aims to balance heat and electricity demand within the system, relying less on the external electricity market. Calliope optimizes the system, seeking minimum total costs, therefore using the lowest-cost alternatives and replacing power plant production with imports whenever this is feasible cost-wise.



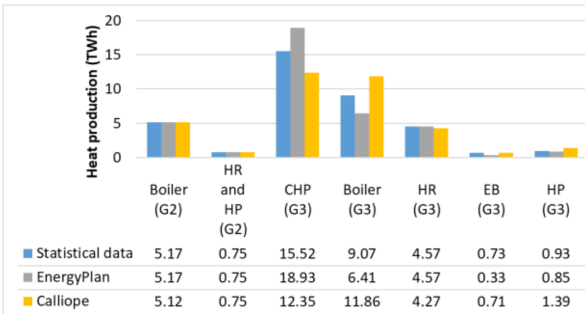
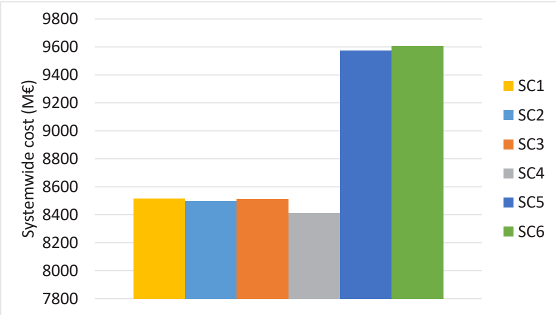


Figure 3. Comparison of the statistical data with simulation results for the 2023 system (Electricity).

Figure 4. Comparison of the statistical data with simulation results for the 2023 system (Heat).

4.2. 2030 scenarios

Fig. 5 displays the total socio-economic costs for SC1-SC6 for 2030. The results highlight the increasing costs in scenarios 5 and 6, due to the limitation in CPP capacity. The model compensates for the lack of CPP generation capacity with a significantly larger BESS, approximately 75 GWh, which causes the increase in systemwide costs. With CPP capacity allowed, the systemwide costs are approximately 8400–8500 M€ for SC1-SC4. Calliope shows slightly lower costs in SC4 with 8413 M€ compared to EnergyPLAN with 8500–8526 M€ in SC1-SC3. This advantage is mostly due to optimized heat generation and storage capacities allowing a lower-cost solution.



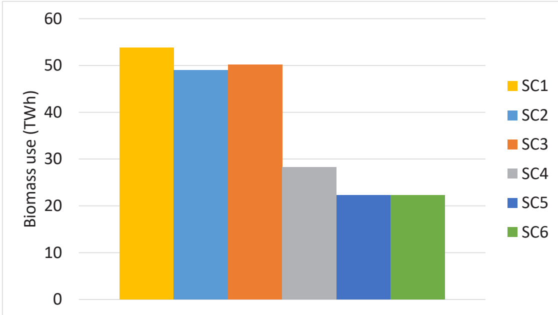


Figure 5. The total annual socio-economic costs of the system in different cases for 2030.

Figure 6. Biomass usage in different cases for 2030.

Calliope utilizes significantly more imported electricity, importing approximately 15 TWh of electricity, therefore decreasing the production of both CHP and CPP (in scenarios where CPP is available). This results in significantly lower biomass usage, of 22–28 TWh, as shown in Fig. 6. EnergyPLAN is exporting 7–8 TWh of electricity, and the biomass usage remains between 49 and 54 TWh. The CEEP in Fig. 7 shows that SC4–SC6 have very low or nonexistent CEEP, while SC1–SC3 show approximately 0.8 TWh to 1.1 TWh of excess production. The difference arises from the distinct modeling approaches, in which SC4–SC6 face fewer constraints regarding the partial loading of various generation technologies.

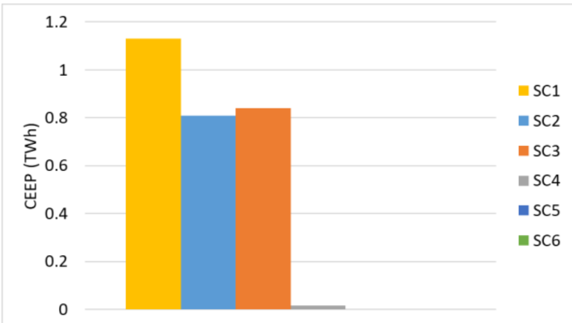
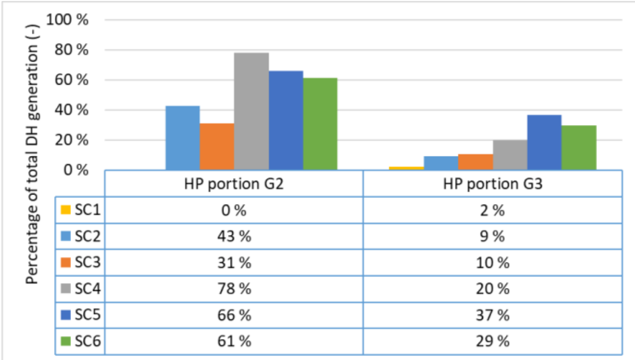


Figure 7. CEEP in different scenarios for 2030.

When comparing the scenarios with different HP capacities, SC2, which has a capacity of 2000 MWth, shows systemwide costs that are 16 M€ lower than those of SC1, totaling 8500 M€ instead of 8516 M€. When TES is not used (SC3), the costs increase by 11 M€, to 8511 M€. The heat pump capacity seems to have only a marginal effect on the systemwide costs, but the changes in biomass use are more significant. In SC2, the higher HP capacity lowers biomass usage from 53.8 TWh to 48.9 TWh, a decrease of 9.1%. SC3, with no TES, increases the biomass usage to 50.1 TWh. Scenarios 4-6 show how the elimination of CPP capacity decreases the biomass usage from 28.2 TWh to 22.3 TWh, although the systemwide costs increase significantly due to this change. The elimination of TES capacity in SC6 has only a small effect on the biomass usage, although the systemwide costs increase 31.9 M€ compared to SC5.

The share of heat generation from HPs is shown in Fig. 8 for the different scenarios. In all scenarios with HP capacity (SC2 to SC6), the share of HP generation in group 2 remains significant, ranging from 31% to 78%. Calliope scenarios SC4–SC6 show higher HP generation than SC1 to SC3. Elimination of TES capacity in SC3 vs. SC2 and SC6 vs. SC5 shows a decrease of 12 percentage points and 5 percentage points in HP generation share. The lower power generation capacity in SC5 compared to SC4 causes a decrease of 12 percentage points in HP generation.

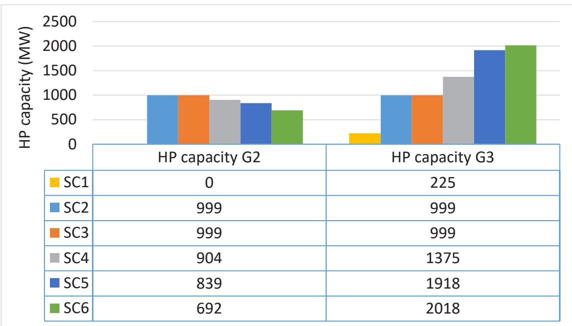
The behavior in group 3 is more complex due to competing heat generation by CHP plants, and the share of heat generation is lower, ranging from 2% to 37%. In SC3 vs. SC2, the heat generation increases 1 percentage point when TES is not used, but in SC6 vs. SC5, the generation decreases 8 percentage points.



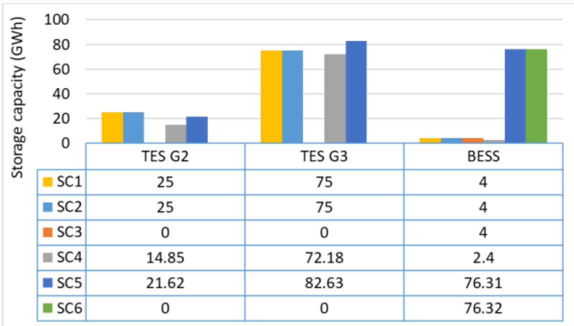
	HP portion G2	HP portion G3
SC1	0 %	2 %
SC2	43 %	9 %
SC3	31 %	10 %
SC4	78 %	20 %
SC5	66 %	37 %
SC6	61 %	29 %

Figure 8. Share of heat generation by heat pumps in each DH groups.

Figs. 9 and 10 show the capacities for HP and TES in groups 2 and 3. For SC1-SC3, the values are a repetition of the modelling assumptions, while for SC4-SC6, the values are the optimization results from the Calliope framework. The optimized HP capacity is relatively stable at 700–900 MWth in G2 and 1400–2000 MWth in G3 across different scenarios. The storage capacity results highlight the BESS capacity change to 76 GWh when CPP is not allowed in SC5 and SC6. The electrical side of the energy system mandates this high capacity at times when the VRE production level remains low. The TES capacity, however, remains quite stable and moderate for SC4 and SC5: 15 to 22 GWh in group 2 and 72 to 82 GWh in group 3. The elimination of TES from the system in SC6 has an almost nonexistent effect on the BESS capacity.



	HP capacity G2	HP capacity G3
SC1	0	225
SC2	999	999
SC3	999	999
SC4	904	1375
SC5	839	1918
SC6	692	2018



	TES G2	TES G3	BESS
SC1	25	75	4
SC2	25	75	4
SC3	0	0	4
SC4	14.85	72.18	2.4
SC5	21.62	82.63	76.31
SC6	0	0	76.32

Figure 9. Heat pump capacity in each DH groups for different scenarios.

Figure 10. Energy storage capacities for different scenarios.

Although multiple energy system scenarios have been evaluated and the role of HPs has been analyzed, not all relevant flexibility options could be included. In particular, demand-response measures in the electricity and industrial sectors, pumped hydropower storage, and bidirectional EV charging have been excluded from the scope of this study. In addition, the sensitivity analysis was limited, relying on a single year of spot-price data and a single COP value for the HP technology. Exploring these variations—together with alternative trajectories for investment costs, fuel prices, and technical parameters—represents a valuable direction for future research.

5. Conclusions

The development of the Finnish energy system was evaluated for the year 2030 using data about projected capacity and demand changes. In particular, the power system is expected to undergo significant changes due to the rapid increase in variable renewable electricity generation from wind and solar power. Two distinct modeling tools were used: EnergyPLAN and Calliope, and both the electricity and district heating sectors were considered, along with increases in HP capacity, TES, and BESS.

The results for different Calliope cost-optimized scenarios for 2030 show that heat pumps are always feasible in the modeled scenarios for district heating systems. In district heating systems without CHP production (group 2), 61% to 78% of heat is generated with HPs. For district heating systems with CHP (group 3), a lower portion, 20% to 37%, of heat is generated through HPs. The existence of TES capacity generally increases HP generation share in the system with both EnergyPLAN and Calliope modeling tools.

The development of the power system has a significant impact on the use of HPs in the heating sector. While this study uses projected estimates for capacity and demand development, the role of dispatchable power generation and transmission capacity becomes increasingly important. Scenarios that studied the system without CPP capacity show that large BESS capacity is needed for balancing the variable renewable electricity production. This relatively expensive storage has a high impact on systemwide costs. The results indicate that TES and BESS capacity do not significantly affect each other—if TES capacity is removed from the system, the BESS capacity remains almost unaffected. This indicates that relatively inexpensive TES capacity cannot significantly decrease the need for electricity generation side balancing technologies, even in scenarios with high electrification in the heating sector. As the sector coupling is a one-way coupling, from electricity to heat, the heating sector cannot compensate for the lack of generation capacity on the electrical side.

However, in scenarios where CPP capacity is not used, the large BESS allows for a higher level of electrification in DH networks that have CHP capacity. Both the CHP and EB heat production decrease, while the HP production share is increased. This improvement is likely due to a more flexible power system, which requires less dispatchable power plant utilization and enables more efficient HP utilization. However, for DH networks without CHP production, the effect is opposite, and HP generation is replaced with HOB. However, these networks still show a large degree of HP generation.

The combination of HP and TES is effective in decreasing systemwide costs, biomass usage, and CEEP. However, the changes in cost and CEEP are relatively small, but biomass usage can be decreased by 9.1% compared to a scenario where HP capacity does not increase in the energy system. Electrifying heating networks with HPs can significantly decrease systemwide fuel consumption while being a cost-efficient solution.

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