



## **TANDEM**

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### **Presentation of dynamic techno-economic analysis for each case study**

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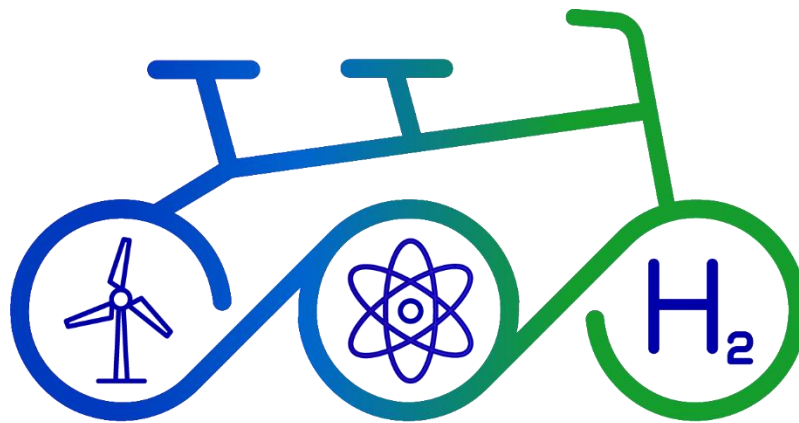
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## Summary

A dynamic global techno-economic and environmental analysis of the hybrid systems in 2035. The data required for the techno-economics analysis of each case study concern: Energy production/ consumption data (hourly energy load profiles, hourly energy production by the different sources, etc), Technological data (energy efficiencies of controllable production units, storage charge/discharge capacities, maximum power ramp speed accommodated by SMRs, etc) Economic data (Capex, Opex, replacement, etc) Environmental data (CO2 direct or grey emissions, CO2 sensitivity taxes, etc).

## Approval

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# TANDEM

## D3.2 – Presentation of dynamic techno-economic analysis for each case study

**WP3 - Task 3.2**

11/06/2024 [M22]

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## Abbreviations and Acronyms

| Acronym           | Description                              |
|-------------------|--|
| ATR               | AutoThermal Reforming                    |
| BESS              | Battery Electric Storage Systems         |
| BO DHN            | Bohumin/Orlova District Heating Network  |
| BOS               | Balance Of System                        |
| CAPEX             | CAPital EXPenditures                     |
| CEC               | Central European Case                    |
| CC                | Carbon Content                           |
| CCGT              | Combined Cycle Gas Turbine               |
| CCS               | Carbon Capture Storage                   |
| CHP               | Combined Heat and Power                  |
| CI                | Carbon Intensity                         |
| CR                | Czech Republic                           |
| DC                | District Cooling                         |
| DH                | District Heating                         |
| DHN               | District Heating Network                 |
| DHC               | District Heating and Cooling             |
| EA                | Emission Allowances                      |
| EF                | Environmental Footprint                  |
| E-SMR             | European Small Modular Reactor           |
| EU                | European Union                           |
| GAMS              | General Algebraic Modelling System       |
| HES               | Hybrid Energy System                     |
| HOB-SMR           | Heat Only Boiler – Small Modular Reactor |
| HP                | Heat Pump                                |
| HTSE              | High Temperature Steam Electrolysis      |
| IRES              | Integrated Renewable Energy System       |
| KH DHN            | Karvina/Havirov District Heating Network |
| LCA               | Life Cycle Assessment                    |
| LCO               | Levelized Cost Of                        |
| LCOE              | Levelized Cost Of Electricity            |
| LCOH              | Levelized Cost Of Heat                   |
| LCOH <sub>2</sub> | Levelized Cost Of Hydrogen               |
| LTE               | Low Temperature Electrolysis             |
| LW-SMR            | Light Water Small Modular Reactor        |



|       |                                  |
|-------|----------------------------------|
| MILP  | Mixed Integer Linear Programming |
| MPC   | Model Predictive Control         |
| MSR   | Moravian-Silesian Region         |
| NEA   | Nuclear Energy Agency            |
| N/A   | Not Applicable                   |
| N.C.  | Not Communicated                 |
| NGCC  | Natural Gas Combined Cycle       |
| NHES  | Nuclear Hybrid Energy System     |
| NPV   | Net Present Value                |
| OPEX  | Operational EXpenditures         |
| ORC   | Organic Rankine Cycle            |
| PEM   | Proton Exchange Membrane         |
| PV    | PhotoVoltaic                     |
| SEP   | State Energy Policy              |
| SMGR  | Steam Methane Gas Reforming      |
| SMR   | Small Modular Reactor            |
| SNG   | Substitute Natural Gas           |
| SOEC  | Solid Oxide Electrolyser Cell    |
| T DHN | Trinec District Heating Network  |
| VRE   | Variable Renewable Energy        |
| WP    | Work Package                     |
| WWHP  | Waste Water Heat Pump            |



## Executive Summary

The present deliverable, Deliverable 3.2 (D3.2), is the main deliverable of Work Package (WP) 3 of the TANDEM (Small Modular Reactor for a European safe and Decarbonized Energy Mix) project, funded by the Euratom programme. It illustrates the implementation of an optimization process based on the minimization of an objective function, related to environmental impact or costs, by finding an optimal sizing of hybrid energy system components; it enables to assess demonstrative case studies. Thus it provides the results of the techno-economic and environmental studies that have been conducted on the three case studies described in Deliverable 3.1 (D3.1). The case studies explore Nuclear Hybrid Energy Systems (NHES) potential in supplying district heating networks and power grids in Northern and Central Europe, as well as generating heat and power while producing valuable commodities like hydrogen in Southern Europe.

To be aligned with the objectives of the project that aims to provide tools and methodologies to study the techno-economic and environmental profitability of NHES, several sections of the present report are dedicated to describe the assumptions and the methodology. Two different tools have been used to investigate the study case: Backbone, developed by VTT, for the Northern European case and PERSEE, developed by CEA, for the Central and Southern European cases.

The most part of the techno-economic and environmental data used in the studies come from open literature. The Backbone code<sup>1</sup> and the model<sup>2</sup> used in the Northern European case are developed as open-source tools using the General Algebraic Modelling System. The Central European and South European cases based their assumptions on open data: mainly on OECD Nuclear Energy Agency (NEA) for the first one and on an internal database built owing to open literature for the second one.

The Northern European case is studied by VTT, the Central European case by UJV and the Southern European case by CEA. They have been conducted independently but due to the fact that both the Southern European and the Central European cases have been conducted with PERSEE tool, they share the same point of view. In these two cases, the study objective is to provide a solution to decarbonize a local energy system providing at the same time electricity/heat and hydrogen, as a technical consultancy or R&D institute commissioned by a governmental organization could do. For the Northern European case, the study objective is to focus on the

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<sup>1</sup> J. Kiviluoma, E. Rinne, T. Rasku, et al., 'Backbone—an adaptable energy system model—GitLab repository', 2018, <https://gitlab.vtt.fi/backbone/backbone>

<sup>2</sup> J. Ikäheimo, T. Lindroos, A. Purhonen, et al. 'North European energy system model —GitLab repository', 2023, [https://github.com/vttresearch/north\\_european\\_model](https://github.com/vttresearch/north_european_model)

decarbonisation of local heat network, electricity supply is not a priority (and could be envisaged as a “boundary condition”), as a District Heating (DH) operator could do.

The main findings and outcomes of the report D3.2, on the three case studies exploring NHES integration in different European regions are as follows:

The Northern European case was studied from a perspective of a district heating operator, investigating NHES as replacement for heat sources relying on fossil fuel fired plants in the Helsinki Metropolitan area. The study conducted using the Backbone tool showed the interest of integrating SMR to supply District Heating networks. From the viewpoint of a district heating operator whose priority is to produce heat as a baseline, small heat only units like LDR-50 – a heat only boiler SMR producing 50 MW<sub>th</sub> – allow the operator to find profitability in the context of Helsinki area in the study presented in this document. Due to a high summer-to-winter variability of the heat demand in Finland and to the seasonal variation of electricity prices in the Finnish market area, base-load units of small capacity are interesting. The E-SMR<sup>3</sup> academic concept can operate in heat/electricity cogeneration mode. It can produce 155 MW<sub>e</sub>/50 MW<sub>th</sub> per unit when hybridized with a heat recovery rate of 10% as assumed in the studies of this document. With the hypotheses from this case study, it would not meet a district heating operator’s profitability expectations. Indeed, the study takes the point of view of a district heating network operator, but does not look at the services rendered to the electricity grid or their remuneration. However, as E-SMR generates mainly electricity, its business model is highly dependent on the electricity market and the size of the power system. An indicator based on the system cost for the power system coupled with the district heating network would take into account the social welfare value of the E-SMR. Also note that the heat recovery ratio of E-SMR could be increased in further studies. A more detailed study of E-SMR electricity generation capabilities would require modelling of the electricity balance in the Nordpool electricity market instead of the electricity price implemented in the Backbone city-level model of the Northern European case.

For the Central European case, the calculations performed have shown the potentiality to decarbonize the production of heat (for district heating), electricity and hydrogen with the use of SMRs, Low Temperature Electrolysers for hydrogen and renewable energies (solar and wind). For the decarbonisation scenarios the Levelized Cost Of Electricity (LCOE) value is about 77€/MWh<sub>e</sub> and the Levelized Cost Of Hydrogen (LCOH<sub>2</sub>) is 5.4 €/kg H<sub>2</sub>. Besides, the Levelized Cost of Heat (LCOH) is about 19 €/MWh<sub>th</sub>. Whereas in the scenarios using CHPs, the hydrogen produced emits at least 8 times more CO<sub>2</sub> than the EU Taxonomy threshold, in the decarbonisation scenarios using SMRs, the required threshold for sustainable hydrogen is reached with a large margin.

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<sup>3</sup> SMR use-case studied in TANDEM to avoid intellectual property issues. It has been developed in the framework of the ELSMOR Euratom project (<http://www.elsmor.eu/>)

Demonstrative results of the Central Europe Case could be easily valorised for decarbonizing other similar territories, such as Silesian Voivodeship in Poland or Žilina self-governing region in the Slovak Republic.

For the Southern European case, the study allowed to identify a configuration with a decarbonisation with about 80% rate compared to the reference “business-as-usual” one - which includes a Combined Cycle Gas Turbine (CCGT) and a Steam Methane Gas Reformer (SMGR) - for an extra cost of 26.1 €/MWh<sub>e</sub> and 2.2 €/kg H<sub>2</sub>. This configuration contains E-SMRs, High Temperature Steam Electrolysers (HTSE) and a hydrogen storage, and produce electricity, heat and low-carbon hydrogen. Furthermore, the flexibility offered by the E-SMR can be used to improve either the hydrogen cost or the carbon intensity of hydrogen in some extend. A carbon cost of 100 €/ton CO<sub>2</sub> eq would cancel the extra cost on the LCOE whereas a carbon cost of 172 €/ton CO<sub>2</sub> eq would lead to the same total costs between the reference and the first configuration with E-SMRs and HTSE thus to very similar LCOE, LCOH, LCOH<sub>2</sub> (as the outputs are nearly identical). It is worth mentioning that the cost of CO<sub>2</sub> reached more than 100 €/ton CO<sub>2</sub> in February 2023.

Overall, the report provides Key Performance Indicators (KPIs) for NHES in three different locations in Europe each one with their own context. **In the three study cases of this report, SMRs can be a relevant option to decarbonize HES.** Nevertheless, depending on the final targeted application, the design and in particular the rate between electricity and extracted heat has to be adapted.

**Furthermore, it is important to remind that the results obtained for the three case studies deeply rely on the assumptions taken into account; the objective targeted here by the TANDEM project is only to be demonstrative.** Besides, even if the present report gives a lot of numerical results, it is better to keep in mind the trends and not the exact values that are of course estimations based on a lot of assumptions, the local European context and the time of the study. Finally, further sensitivity studies are also necessary to put in perspectives these results in sight of some uncertain assumptions that were taken into account.

## Keywords

SMR, Nuclear energy, Hybrid Energy Systems, District heating, Power supply, Energy Hub, Techno-economic and environmental study, Optimal sizing, Minimization of an objective function, Case study

## 1 Introduction

The TANDEM (Small Modular Reactor for a European safe and Decarbonized Energy Mix) project, funded by the Euratom programme, aims to facilitate the integration of Small Modular Nuclear Reactors (SMR) into Hybrid Energy Systems (HES) with a focus on nuclear safety assessments, techno-economic and environmental profitability, and operation feasibility. In pursuit of this goal, the project will develop essential tools, including an open-source MODELICA library and methodologies, to be applied in two configurations across three case studies. These configurations are designed to supply district heating networks and power grids in Northern and Central Europe and to generate heat and power while producing valuable commodities in an energy hub, particularly hydrogen, in Southern Europe.

As part of Work Package (WP) 3, the TANDEM project delves into the operability, profitability, and environmental impact of Nuclear Hybrid Energy Systems (NHES) through dynamic techno-economic and environmental assessments. To carry out these crucial studies, appropriate tools are employed, and special emphasis is placed on sharing the methodology of such assessments. For the Northern Europe case, the Backbone tool, developed by VTT, is used to conduct the techno-economic and environmental study, while the PERSEE tool, developed by CEA, is deployed for the Southern and Central Europe cases. The Northern European case is studied by VTT, the Central European case by UJV and the Southern European case by CEA. Besides, the operation of the system is analysed using the ECOSIMPRO tool, developed by EAI, or through a coupling between the PERSEE tool and the MODELICA open-source library, developed in WP2.

The detailed description of the three case studies is the object of Task 3.1 and its associated deliverable gathers the description of each case with several techno-economic and environmental assumptions. Task 3.2 within the TANDEM project is dedicated to the dynamic techno-economic and environmental study of the three case studies. The Key Performance Indicators (KPI) are really dependent on the assumptions used to model each case thus the present deliverable presents in details the assumptions. Considering the fact that this European project aims to provide tools and methodologies to study the techno-economic and environmental profitability of Nuclear HES (NHES), the description provided in the case should be enough to reproduce the results. Then, the present deliverable analyses the results obtained for each case study.

## 2 E-SMR modelling

The E-SMR concept developed in the ELSMOR project is used in the three case studies. The techno-economic and environmental assumptions that are considered are thus described in this

chapter. Nevertheless, as different tools are used to model the study cases, the tool specific assumptions are described in the relevant section.

The reference E-SMR unit is made up of two twin E-SMR reactors of 540 MW<sub>th</sub> resulting in 340 electrical MW delivered by the whole system. The E-SMR can also deliver heat with a range of temperature between 150°C and 250°C available for coupling but it goes hand in hand with a decrease of the electricity delivery. For this study, the reference case is a 10% heat recovery. The heat recovery range is [10%, 20%]. The Figure 1 shows the 3 different possible cogeneration modes which can be modelled by simulation tools (Backbone, PERSEE). The base cogeneration mode (type 1) where electrical and thermal efficiency are constant with a 10% heat recovery (310 MW<sub>e</sub> and 100 MW<sub>th</sub>, at 100% nominal power). The type 2 and 3 cogeneration modes can modulate the E-SMR operation according to the thermal and electrical needs. The type 3 model is a variable downwards heat recovery and results in a 340 MW maximum electrical supply and the type 2 model is the variable upwards heat recovery (from 10 to 20%).

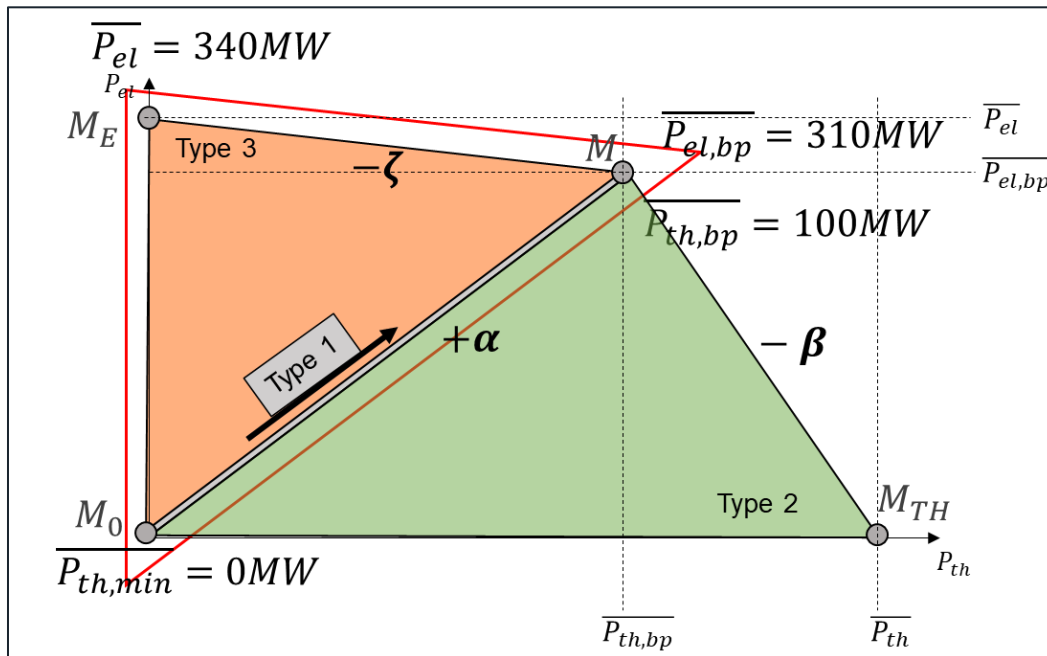


Figure 1: E-SMR different cogeneration modes

Finally, according to the level of detail of the E-SMR modelling, Table 1, Table 2 and Table 3 gather the main techno-economic and environmental data considered [1][2]. Values were updated since TANDEM/deliverable D1.3 [3] to follow the evolution of the literature.

| Parameter name         | Unit            | Value |
|------------------------|-----------------|-------|
| Maximal electric power | MW <sub>e</sub> | 340   |
| Heat recovery rate     | %               | 10    |

|  |                  |     |
|--|------------------|-----|
| Thermal power at 100% hybridization <sup>4</sup> | MW <sub>th</sub> | 100 |
| Electrical power at 100% hybridization           | MW <sub>e</sub>  | 310 |
| Load factor                                      | %                | 92  |

**Table 1: Technical parameters of E-SMR**

| Parameter name       | Unit                                | Value   |
|----------------------|-------------------------------------|---------|
| Design lifetime      | years                               | 60      |
| CAPEX (overnight)    | € <sub>2023</sub> /MW <sub>e</sub>  | 6050000 |
| Variable cost (OPEX) | € <sub>2023</sub> /MWh <sub>e</sub> | 24.4    |
| Fuel cost (OPEX)     | € <sub>2023</sub> /MWh <sub>e</sub> | 7.4     |

**Table 2: Economic parameters of E-SMR**

| Parameter name                            | Unit                                   | Value |
|---|--|-------|
| Direct emissions (electricity production) | kg CO <sub>2</sub> eq/MWh <sub>e</sub> | 4.1   |
| Direct emissions (heat production)        | kg CO <sub>2</sub> /MWh <sub>th</sub>  | 1     |

**Table 3: Environmental parameters of E-SMR**

These assumptions lead to an operating cost of 31.8 €<sub>2023</sub>/MWh<sub>e</sub> for the E-SMR. CAPEX value is based on literature review conducted by CEA. For example, in [4], 3874 EUR/kW<sub>e</sub> is considered and in [5], 7712 EUR/kW<sub>e</sub> is taken into account. These two examples leads to an average value of 5793 EUR/kW<sub>e</sub> but by taking into account more references, CEA proposed to take 6050€/kW<sub>e</sub>.

## 3 Northern European case

### 3.1 Context

Finland has ambitious plans for the decarbonisation of various sectors to meet the commitments outlined in the Paris Climate Agreement [6]. In 2019, energy-related greenhouse gas emissions accounted for 72% (39 Mt CO<sub>2</sub> eq) of the total emissions (53 Mt CO<sub>2</sub> eq), and specifically emissions related to the production of district heating, electricity, and industrial process heat stood for 30 % (16 Mt CO<sub>2</sub> eq) of the total emissions [7]. This study will focus on the decarbonisation of the district heating system in the metropolitan area of Helsinki, including the capital of Finland and the large cities of Espoo (population of 293,000) and Vantaa (population of 237,000). District heating production in each city is handled by separate companies: Helen Ltd. in Helsinki, Fortum Ltd. in Espoo, and Vantaa Energia Ltd. in Vantaa. The district heating networks from Espoo and Vantaa connect to the Helsinki district heating network with limited transfer capacity. Although the use of heat pumps and biomass has been increasing in the Helsinki metropolitan area, the district heating supply still relies on natural gas and coal-fired power plants. Waste incineration in Vantaa produces a significant amount of energy demand in the area,

<sup>4</sup> 100% hybridization is the operation mode where the heat recovery is used at its maximum.

about half of the district heat demand and 30 % of the electricity demand [8]. More detailed description of the district heating supply and demand in the Helsinki metropolitan area is described in the model and scenario description of the study.

The decarbonisation objectives for Helsinki are described in the Carbon Neutral Action Plan [9], including the development program of Helen Ltd. The prevailing objective of Helen Ltd. is to adhere to the national prohibition on coal in the energy sector starting from 2030 [10]. To identify the most viable strategies for this transition, the city of Helsinki introduced an international contest, the Helsinki Energy Challenge [11], which showcased an extensive array of solutions involving heat pumps and heat storage. The importance and potential of distribution temperatures within the district heating network were also recognized. Also, decarbonisation ambitions in the city of Espoo are being executed through the Espoo Clean Heat project by Fortum Ltd., to eliminate coal usage in Espoo's district heating production by 2025 and prioritize biomass utilization, wastewater, and data centre-based heat pumps [12]. Lastly, the city of Vantaa has outlined an action plan aiming to achieve carbon neutrality by 2030. According to the plan, the Vantaa district heating system would combine waste incineration with biomass combustion, waste heat utilization, and geothermal heat pumps. In summary, the entire metropolitan energy goals present a compelling basis for analysing decarbonisation measures of district heating systems.

In the pursuit of decarbonisation, novel small modular reactors emerge as a promising solution for clean and reliable energy production. These compact nuclear power plants offer a pathway to carbon-free district heating while balancing the price fluctuations of heat energy and supporting Finland's security of supply. Steady Energy and Helen have signed a letter of intent to enable an investment in small-scale nuclear power for district heat production. Steady Energy is a Finnish company commercializing heat producing SMR technology developed at VTT. The letter of intent aims to promote the reform of the Finnish Nuclear Energy Act, apply for a siting license and design review and fixing the contract price for the plant. The agreement also enables Helen to procure up to ten reactor units with an output of 50 MW from Steady Energy [13].

The following chapters start by describing the case study. This is followed by an introduction to the computational tool used in this study, Backbone, and the description of the Helsinki Metropolitan model that was implemented with the Backbone. Next, the baseline model and studied SMR models are discussed, along with the studied impacts. The discussion then progresses to the presentation of the E-SMR and LDR-50 scenarios, along with the results calculated from each respective scenario. The Northern European case study finished with conclusion of the findings.

### 3.2 Case study description

To achieve the ambitious decarbonisation plans in the District Heating and Cooling (DHC) system of the Helsinki Metropolitan area, new investments in energy systems and technologies are needed to replace the fossil fuel-based District Heating (DH) production. In this regard, the following scenarios are compared:

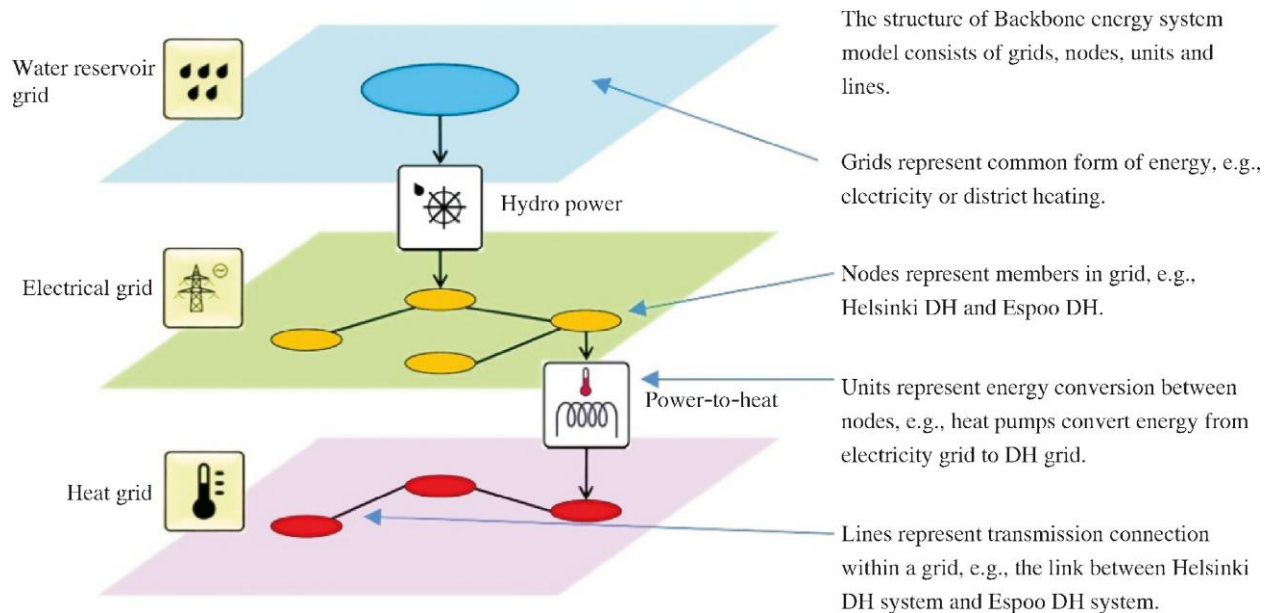
- No additional investments
- Combined heat and power SMRs (E-SMR)
- Heat Only Boiler SMRs (LDR-50)

An investment analysis based on an optimization model is employed to assess the 2035 scenarios. The assessment focuses on evaluating the new capacity, costs, and emissions associated with each scenario. Sensitivity analysis considering different assumptions regarding the existing DHC system, investment costs, and electricity prices are performed in the following deliverable.

#### 3.2.1 Description of Backbone and the district heating system model

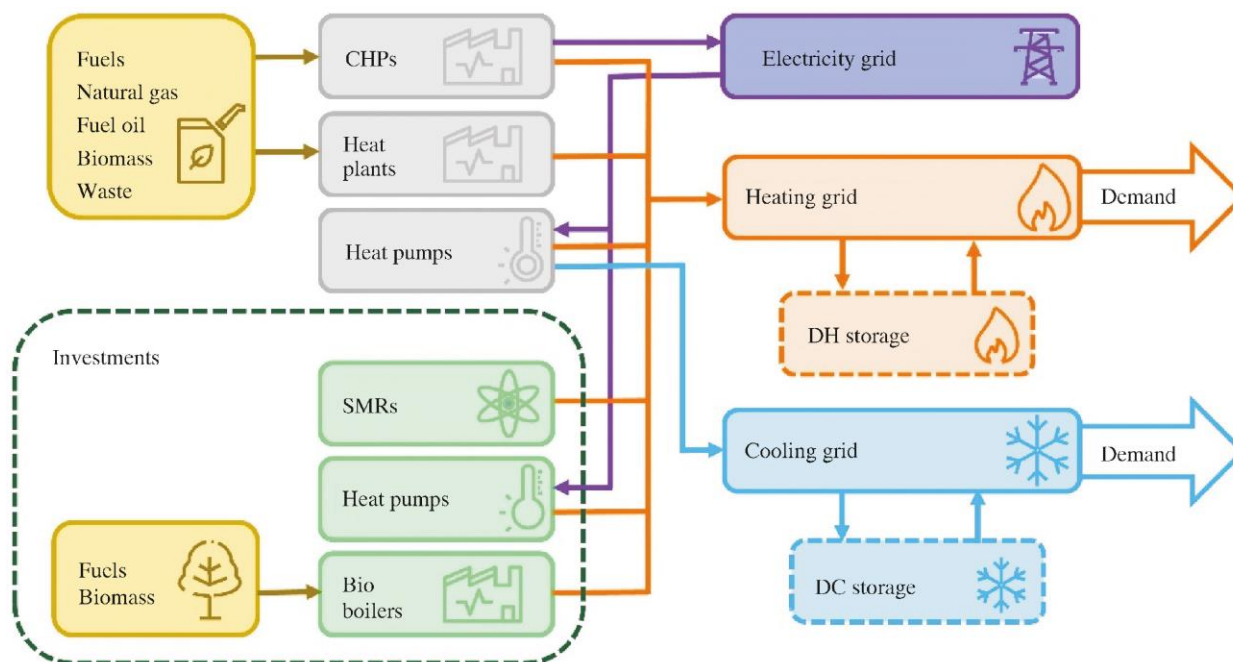
Backbone is an adaptable energy systems modelling framework designed for studying the design and operation of energy systems, for both operational scheduling and investment planning. The framework has been developed as an open-source tool (available online in [14]) using the General Algebraic Modelling System (GAMS). Backbone can model both high-level large-scale systems and fully detailed smaller-scale systems. The framework is based on mixed-integer programming, and it features unit commitment decisions for power plants and other energy conversion facilities. The formulations and equations that Backbone is built upon are described in detail by Helistö et al. [15].

The structure of Backbone models is defined through parameter settings and input data, rather than hard-coded structures, allowing for the creation of various models for different purposes using the same data set. The Backbone model used in this work represents the Helsinki metropolitan area's district heating and cooling system. The model topology is composed of grids, nodes, units, and lines as can be seen from Figure 2. These elements define the energy system model's physical layout. Specific data relevant to the Helsinki metropolitan area such as regional demand time series of district heating and district cooling are implemented in the model. Documentation and validation of the Helsinki metropolitan area model are explained in detail by Pursiheimo et al. [16].



**Figure 2: The network structure of Backbone model and short description of the elements in the structure.**

The implementation of the energy system model (available online in [17]) for the Helsinki metropolitan DHC system involves integrating the DH and District Cooling (DC) production and storage structure into the Backbone model framework. The fundamental structure of the DH system is depicted in Figure 3; however, it should be noted that the figure does not show the division of the DH system into model regions, which include the DH grids of Helsinki 1, Helsinki 2, Espoo, Vantaa, and their interconnections. Additionally, the DH system is interconnected with the national electricity grid to facilitate the supply of electricity to heat pumps and enable the sale of electricity generated by Combined Heat and Power (CHP) units to the Nordic electricity market. The electricity generated is sold at price defined by time series data of electricity price, electricity balance is not modelled.



**Figure 3: The simplified illustration of the district heating and cooling energy system model.**

### 3.2.2 Modelled 2035 baseline scenario

The Northern European case studies the novel technologies from the perspective of a district heating operator in the Helsinki Metropolitan area. Thus city level heat demand is modelled, while electricity balance of Finland is not. Instead of modelling the electricity balance, electricity price based on time series data is used as a boundary condition for the model. Electricity price modelling and its impact on the economical calculations are explained in Chapter 3.2.4. District heating operators produce energy to satisfy the heat demand and sell electricity to the grid if it is profitable. Thus, modelling of electricity balance is not relevant for this study.

Warm household water requires district heating all year round, and the DH demand is highest in winter when the outdoor temperature is lowest. The district cooling is mostly used in summer, but some big buildings and shopping centers also need cooling in winter. The time series used in the model can be seen from Figures 4-6. The time series data are based on year 2019. The heat demand data for Helsinki was sourced from Helen's open data website [18]. Helen provides hourly information on district heating power in Helsinki. Additionally, the electricity price data was obtained from Nord Pool [19]. The electricity price time series are based on the Finnish spot market of 2019. Unfortunately, no data is available for district heating in Espoo and Vantaa, nor for the district cooling demand of the Helsinki metropolitan area. To address this, the heat demand for Espoo and Vantaa is scaled from the data provided for Helsinki. The district cooling demand of Helsinki and Espoo was calculated based on assumptions derived from the baseline demand of the regions.

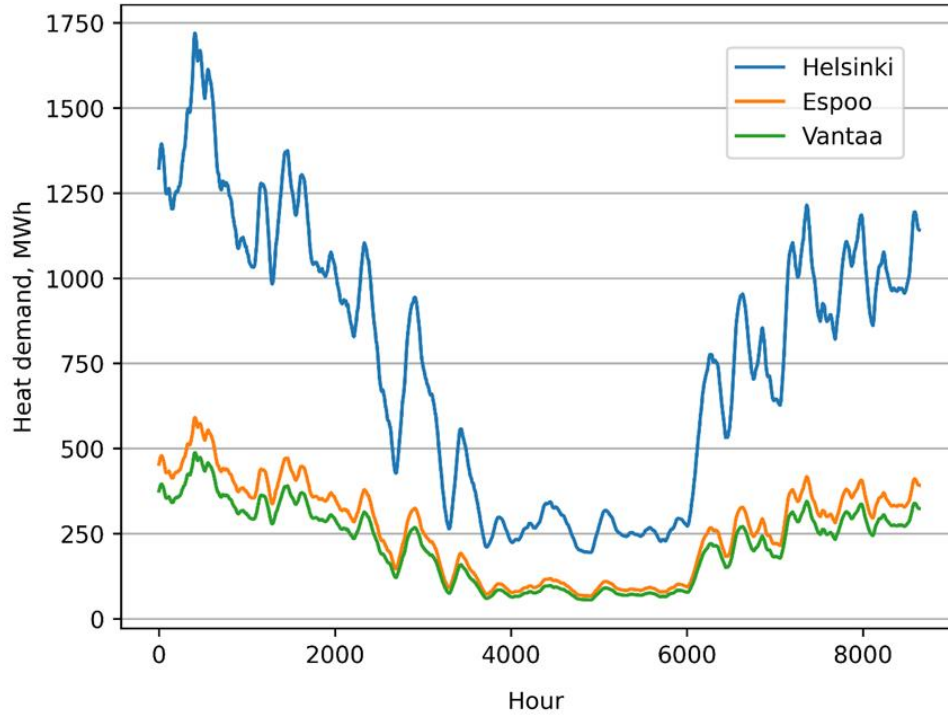


Figure 4: Heat demand in the Helsinki metropolitan area.

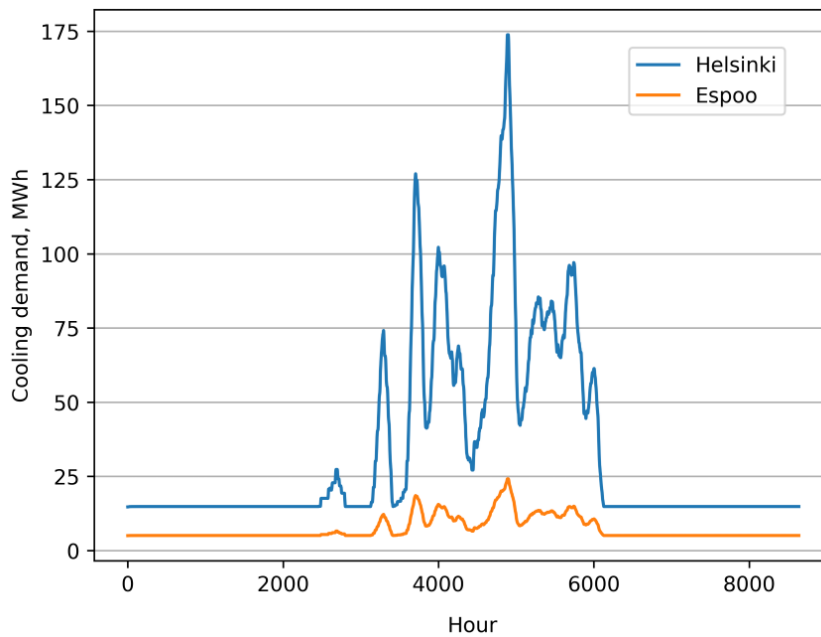
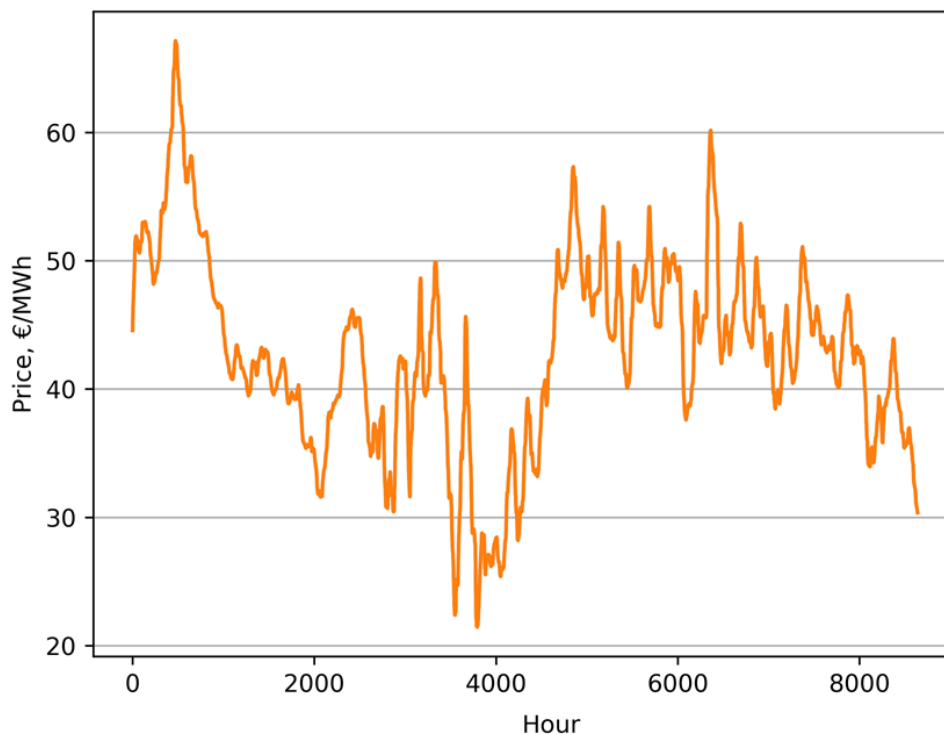


Figure 5: Cooling demand in the Helsinki metropolitan area.





**Figure 6: The price of electricity in the Helsinki metropolitan area.**

Assumed energy prices and taxes for 2030 scenario are modelled as constant and they can be seen from Table 4. Backbone also supports timeseries, but we assume constant prices for fuels and taxes. The energy prices and taxes are based on the current system, with the following adjustments:

- A 10 % increase has been applied to the real values for taxes on fossil fuels.
- Taxes on electricity have been reduced for large heat pumps, in accordance with a proposal from the current Finnish Government.
- Carbon dioxide emissions are priced at 70€/ton of CO<sub>2</sub> in the emission trading system.

| Model parameter for year 2030     | Value (€ <sub>2030</sub> /MWh) |
|-----------------------------------|--------------------------------|
| Natural gas price                 | 40                             |
| Biomass price                     | 39                             |
| Fuel oil price                    | 80                             |
| Synthetic gas price               | 120                            |
| Synthetic oil price               | 120                            |
| Grid fee + taxes for electricity* | 20                             |
| Heat tax for natural gas**        | 15.7***/22.7                   |



|                         |      |
|-------------------------|------|
| Heat tax for fuel oil** | 27.9 |
|-------------------------|------|

\* for consumed electricity

\*\* for produced heat energy

\*\*\* for produced heat energy in CHP plants

**Table 4: Energy prices and energy taxes used in the model for 2035 scenario.**

The modelled production capacity for 2035 scenario can be seen in detail from Table 5. District cooling can be obtained from heat pumps, compression chillers, or free cooling utilizing seawater. Moreover, heating and cooling are byproducts of the power-to-gas process. The district heating and cooling networks are localized within the city, while electricity and natural gas can be imported from or exported to national transmission grids.

The details of the DH and DC storages used in the model are listed in Table 6 and Table 7 shows transmission capacities between model regions.

| Unit               | Type       | Fuel           | DH Capacity (MW) | DC Capacity (MW) | Electricity Capacity (MW) | Total Efficiency (%) |
|--------------------|------------|----------------|------------------|------------------|---------------------------|----------------------|
| <b>Helsinki 1</b>  |            |                |                  |                  |                           |                      |
| Vuosaari NGCC      | NGCC       | Gas            | 470              | -                | 430                       | 91                   |
| Katri Vala HP      | Heat pump  | Electricity    | 158              | 104              | -53                       | 500                  |
| Esplanadi HP       | Heat pump  | Electricity    | 22               | 15               | -7                        | 505                  |
| Vuosaari HP        | Heat pump  | Electricity    | 13               | 10               | 4                         | 520                  |
| Data centre HP*    | Heat pump  | Electricity    | 15               | -                | -5                        | 300                  |
| Electric boilers** | Heat plant | Electricity    | 280              |                  | 280                       | 100                  |
| Absorption HP      | Cool plant | DH/Electricity | -90              | 90               | -5                        | 90                   |
| Salmisaari BIO     | Heat plant | Biomass        | 92               | -                | -                         | 92                   |
| Vuosaari BIO       | Heat plant | Biomass        | 260              | -                | -                         | 108                  |

|             |            |          |       |   |   |    |
|-------------|------------|----------|-------|---|---|----|
| Gas boilers | Heat plant | Gas      | 220   | - | - | 90 |
| Oil boilers | Heat plant | Fuel oil | 1,105 | - | - | 90 |

**Helsinki 2**

|             |            |          |     |   |   |    |
|-------------|------------|----------|-----|---|---|----|
| Gas boilers | Heat plant | Gas      | 350 | - | - | 90 |
| Oil boilers | Heat plant | Fuel oil | 108 | - | - | 90 |

**Espoo**

|                 |            |                |     |    |      |     |
|-----------------|------------|----------------|-----|----|------|-----|
| Suomenoja NGCC  | NGCC       | Gas            | 214 | -  | 234  | 90  |
| Suomenoja CHP   | CHP        | Gas            | 75  | -  | 45   | 90  |
| Suomenoja HP    | Heat pump  | Electricity    | 60  | 30 | -20  | 450 |
| Data centre HP* | Heat pump  | Electricity    | 350 | -  | -116 | 300 |
| Absorption HP   | Cool plant | DH/Electricity | -30 | 30 | -2   | 90  |
| Kivenlahti BIO  | Heat plant | Biomass        | 52  | -  | -    | 104 |
| Gas boilers     | Heat plant | Gas            | 500 | -  | -    | 90  |
| Oil boilers     | Heat plant | Fuel oil       | 230 | -  | -    | 90  |

**Vantaa**

|                   |            |            |     |   |    |    |
|-------------------|------------|------------|-----|---|----|----|
| Waste CHP         | CHP        | Waste fuel | 119 | - | 81 | 97 |
| Martinlaakso NGCC | NGCC       | Gas        | 124 | - | 57 | 82 |
| Martinlaakso CHP  | CHP        | Biomass    | 80  | - | 30 | 92 |
| Waste boiler      | Heat plant | Waste fuel | 65  | - | -  | 85 |
| Gas boilers       | Heat plant | Gas        | 497 | - | -  | 90 |

|             |            |          |    |   |   |    |
|-------------|------------|----------|----|---|---|----|
| Oil boilers | Heat plant | Fuel oil | 92 | - | - | 90 |
|-------------|------------|----------|----|---|---|----|

\* Assumed data centre investment

\*\* Assumed electric boiler investment

**Table 5: Details of the modelled production capacity (NGCC = natural gas combined cycle, CHP = combined heat and power).**

| Storage unit                    | Type | Storage size (MWh) | Charge/discharge capacity (MW) |
|---------------------------------|------|--------------------|--------------------------------|
| <b>Helsinki 1</b>               |      |                    |                                |
| Salmisaari/Vuosaari/Mustikkamaa | DH   | 13,600             | 140                            |
| Generic cold storage            | DC   | 500                | 5                              |
| <b>Espoo</b>                    |      |                    |                                |
| Suomenoja                       | DH   | 1,600              | 40                             |
| <b>Vantaa</b>                   |      |                    |                                |
| Martinlaakso                    | DH   | 900                | 20                             |
| Large-scale storage             | DH   | 90,000             | 200                            |

**Table 6: Details of the modelled storage units.**

| Transmission capacity (MW) | Helsinki 1 | Helsinki 2 | Espoo | Vantaa |
|----------------------------|------------|------------|-------|--------|
| <b>Helsinki 1</b>          | -          | 140        | 40    | 54     |
| <b>Helsinki 2</b>          | 140        | -          | -     | 6      |
| <b>Espoo</b>               | 40         | -          | -     | -      |
| <b>Vantaa</b>              | 54         | 6          | -     | -      |

**Table 7: District heating transmission capacity between model regions.**

Certain conversion units were assumed to be existing legacy units within the model. These units included a CCGT, a CHP plant with a capacity of 220 MW<sub>e</sub>, gas boilers, and a Waste Water Heat Pump (WWHP). These types of plants are currently present in Espoo. However, new investments in these units were not permitted due to economic considerations for the CHP plant. The gas boilers were assumed to provide district heating reserve capacity during contingencies, and thus their capacity was not limited. The WWHP capacity (70 MW<sub>th</sub>) was determined based on the available waste water and cooling demand. Additionally, a small biogas engine with a capacity of 15 MW<sub>e</sub> was also included in the model. Heat pumps and electric boilers use electricity purchased from the Finnish electricity market, which is determined by the time series data. About 86% of the electricity production in Finland was fossil-free in 2021 [20].

### 3.2.3 Modelled SMR investments

In addition to the existing installed capacity, two innovative Small Modular Reactor (SMR) technologies have been incorporated into the city-level Backbone model of Helsinki Metropolitan Area. These novel technologies were simulated as new investments within their respective scenarios. In the Backbone model, the new investments are connected to the DH network of Helsinki. Technical and economic assumptions for these SMR technologies are summarized in Table 8. Value at the end of the economic lifetime was calculated by applying a consistent annual depreciation rate of seven percent over 20 years.

| Technology   | E-SMR   | LDR-50 |
|--|---------|--------|
| Reactor units in a single module                       | 2       | 2      |
| Heat capacity (MW)                                     | 100     | 100    |
| Power generation capacity (MW)                         | 340     | -      |
| Minimum load (-)                                       | 0.4     | 0.2    |
| Efficiency (-)   | 0.41    | 1      |
| CAPEX (€ <sub>2023</sub> /kW <sub>th</sub> )           | 1905*   | 1500*  |
| OPEX (€ <sub>2023</sub> /MW <sub>th</sub> )            | 10.01** | 6.3*** |
| Investment cost (M€)                                   | 2057    | 150    |
| FOM (% of CAPEX)                                       | 0       | 3      |
| Construction time (years)                              | 2       | 2      |
| Economic lifetime (years)                              | 20      | 20     |
| Discount rate (%)                                      | 7       | 7      |
| Value at the end of the economic lifetime (% of CAPEX) | 23      | 23     |

\* costs correspond to the steam production capacity of the reactor.

\*\* OPEX for E-SMR combines variable cost of 24.4 €/MWh<sub>e</sub> and fuel cost 7.4 €/MWh<sub>e</sub>.

\*\*\* OPEX for LDR-50 concerns all variable costs including fuel related costs.

**Table 8: Economic assumptions for the new investments in the model.**

In Table 8, the capital expenditures and operational costs for E-SMR were converted from electric output to thermal input to facilitate a more accurate comparison of SMR technologies. The CAPEX was recalculated from 6050 €<sub>2023</sub>/kW<sub>e</sub> to 1905 €<sub>2023</sub>/kW<sub>th</sub> by applying the system's efficiency. Similarly, the OPEX was derived by summing the variable and fuel costs, which were then multiplied with the efficiency to obtain the OPEX.

The E-SMR model also includes a turbine bypass; for detailed specifications of the reactor technology, see Chapter 2.

LDR-50 reactor has been in development at VTT since 2020 for low-temperature heat applications [21]. The reactor is a 50 MW<sub>th</sub> integrated pressure water reactor that operates on the principle of natural circulation without boron. The reactor design incorporates in-vessel control rods, self-pressurization, and a passive decay heat removal system. The reactor is tailored to produce heat into district heating networks for cities of varying sizes, from small municipalities to large urban centres. In this work, the reactor is studied for district heating, but additionally, LDR-50 is being explored for other low-temperature heat applications such as desalination, hydrogen production, and direct air capture of CO<sub>2</sub> [22].

### 3.2.4 Studied impacts

In this study, the costs in the Helsinki metropolitan area are calculated by comparing the baseline scenario and the SMR investment scenarios. Two key financial metrics: Internal Rate of Return (IRR) and Net Present Value (NPV) are used to investigate feasibility of the SMR investments.

The NPV depicts the value of all future cash flows over the lifetime of an investment discounted to the present [23]. NPV considers all revenues, expenses, and capital costs associated with the investment. See equation 1 below:

$$NPV = \sum_{t=0}^n \frac{R_t}{(1+i)^t} \quad (1)$$

where

NPV is the net present value,

n is the total number of periods,

R<sub>t</sub> is the net cash flow during a single period t,

i is the discount rate,

t is the number of time periods.

IRR is used to evaluate the effective interest rate returned on an investment [24]. IRR is calculated similarly to the net present value, except that it sets the NPV value equal to zero. See equation 2 below:

$$0 = NPV = \sum_{t=1}^T \frac{C_t}{(1+IRR)^t} - C_0 \quad (2)$$

where

$C_t$  is the net cash inflow during the period  $t$ ,

$C_0$  is the total initial investment costs,

IRR is the internal rate of return.

Backbone uses a single data set, time series year 2019, for modelling the electricity price. The data is shown in Figure 6. The economic calculations use the same data set for the entire lifetime of the SMR investments. Backbone supports modelling of electricity balance, but the Northern Case is studied from the perspective of a district heating operator located in the Helsinki Metropolitan area. District heating operators prioritize heat production and sell electricity to the grid when it is profitable. Thus, the used city-level Backbone model does not include electricity balance in this study.

The use of electricity price modelling simplifies the NPV and IRR calculations for the E-SMR scenario. This is a limitation because the electricity price is affected by changes in electricity production capacity, which is not considered in the model. The E-SMR modules can sell all their electricity at the price given by the selected time series year. A more detailed study would require modelling the electricity balance to assess the electricity generation potential of E-SMRs in the region, but that is beyond the scope of this work. In Task 3.3, the impact of selected time series year on profitability of the investments will be studied by performing sensitivity analyses.

### 3.3 Scenario A –with E-SMR deployment in 2030

#### 3.3.1 Presentation of the scenario

The Northern European case focuses on the integration of SMRs with renewable energy sources, such as wind and solar power in the Helsinki Metropolitan area. This scenario involves a comprehensive study of various E-SMR deployments to assess their operability, profitability, and environmental impact within the region.

#### 3.3.2 Results

The results from E-SMR scenarios are presented in this chapter. In the figures, each E-SMR module consists of 2 reactor units. Figure 7 and Figure 8 illustrate the heat and electricity production breakdown by area and type within the Helsinki metropolitan region. With just the existing production capacity, Helsinki produces approximately 11 TWh of thermal energy and around 1 TWh of electricity. Heat storages are not taken into account in Figure 7 (a).

The implementation of E-SMRs in the Helsinki metropolitan area primarily replaces production from Helsinki and slightly from Vantaa and Espoo. When we look at the fuel type, the proportion of heat generated from fossil and bio fuels decreases, as does the share of heat pumps and electric boilers.

The Helsinki metropolitan area has limited electricity production capacity which can be clearly seen from Figure 8. The introduction of even a single E-SMR module would significantly increase the area’s electricity generation, more than doubling the production in the area. The unit size of an E-SMR module is considerably large for the area.

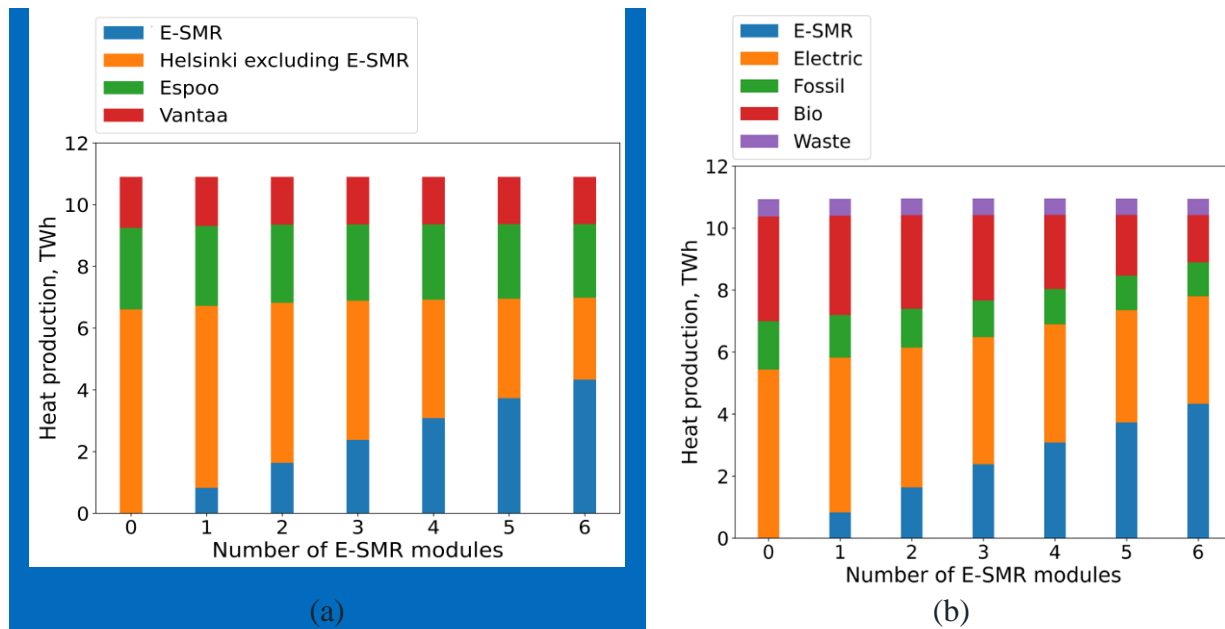
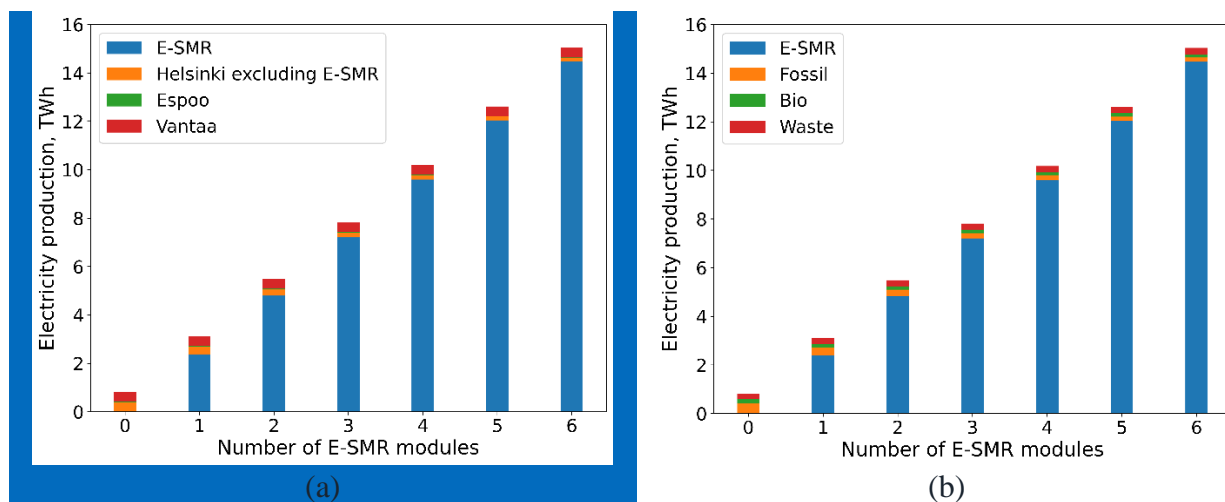


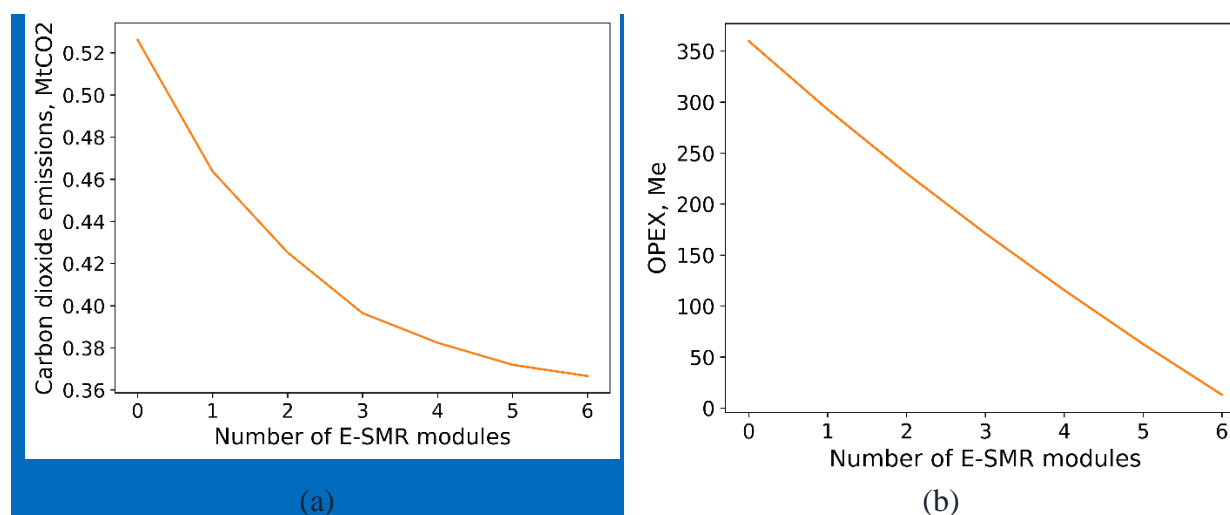
Figure 7: Yearly heat production by (a) area and (b) fuel type in the Helsinki metropolitan area.



**Figure 8: Yearly electricity production by (a) area and (b) fuel type in the Helsinki metropolitan area.**

As E-SMR modules are implemented into the Helsinki metropolitan area, the yearly carbon dioxide emissions drop from 0.52 (no E-SMR implement) to 0.38 MtCO<sub>2</sub>. (6 E-SMR implemented). See Figure 9 (a). The reduction in emissions comes from the replacement of bio and fossil-fuelled power plants in the district heat and electricity generation of the Helsinki metropolitan area. The E-SMR investments can only replace units that are included in the model. The units modelled were listed in Table 5. This approach simplifies the E-SMR scenario since units outside the Helsinki metropolitan area are not affected by electricity generation of E-SMRs.

As the emission drops, so do the energy system costs of the Helsinki Metropolitan area. The energy system costs drop significantly from 360 M€ to 13 M€. E-SMR modules sell electricity outside the model in huge volumes for profit, and thus, the yearly energy system costs in the area are reduced significantly. Note that increase in electricity generation does not impact the electricity price. See Figure 9 (b) for clarity.

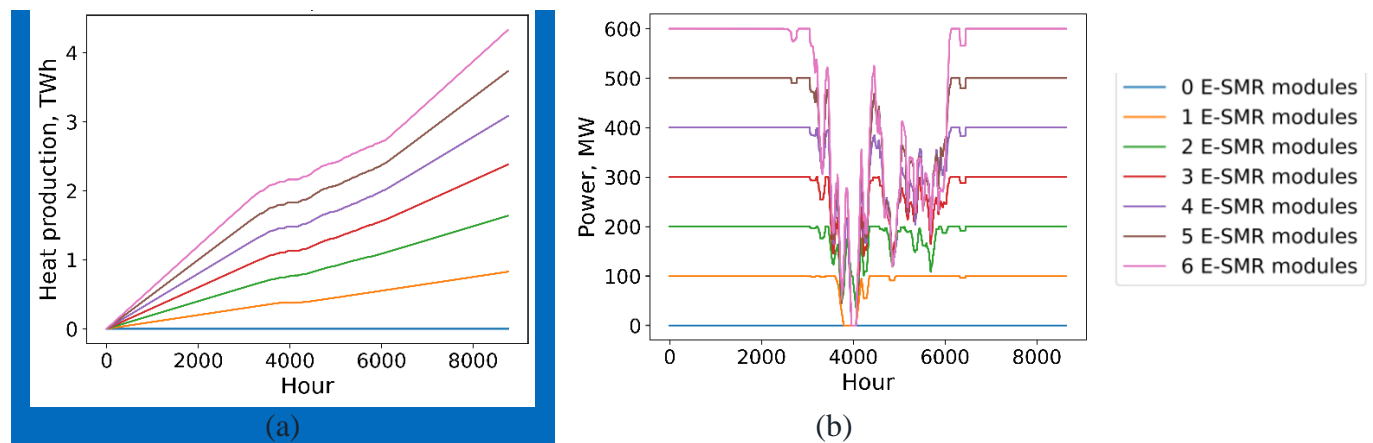


**Figure 9: Yearly reduction of (a) CO<sub>2</sub> emissions and (b) energy system costs in the Helsinki metropolitan.**

In Figure 10 (b) and Figure 11 (b), it can be seen that the E-SMR modules go offline during the summer for different periods of times depending on the number of modules. Finland has strong seasonal fluctuations in the heat demand and simultaneously the electricity price. This causes plateaus in the cumulative energy production, especially in the heat generation, impacting profitability of the SMR investments, from the viewpoint of a district heating operator. See Figure 10 (a) and Figure 10 (a).

The curves in heat generation of each scenario do not follow identical pattern. This is because the Helsinki metropolitan area has big seasonal heat storages which contribute during the

summer at different levels depending on the heat production capacity of the E-SMRs in each scenario. See Table 6 for modelled storage units.

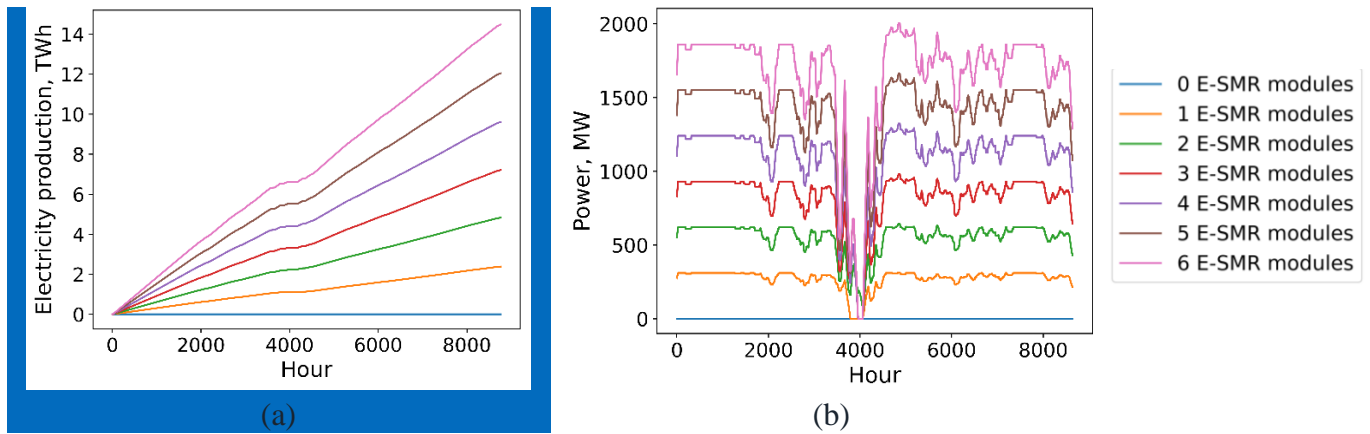


**Figure 10: (a) Cumulative heat production and (b) DH power level of E-SMR modules on one year (0h corresponding to the beginning of January).**

Before delving into rest of the results, few simplifications need to be explained. The SMR investments are studied from point of view of a DH system operator. A DH system operator is responsible for providing heat but can produce or not produce electricity depending on market prices. Our modelling follows this business logic and thus, the used city-level Backbone model does not include electricity balance. Instead, the model uses electricity price time series data of year 2019. It must be noted that the year 2019 had relatively low electricity price. In the economic calculations, the year 2019 electricity price is assumed for the whole lifetime of the investment. The used price year is a central topic for sensitivity analysis.

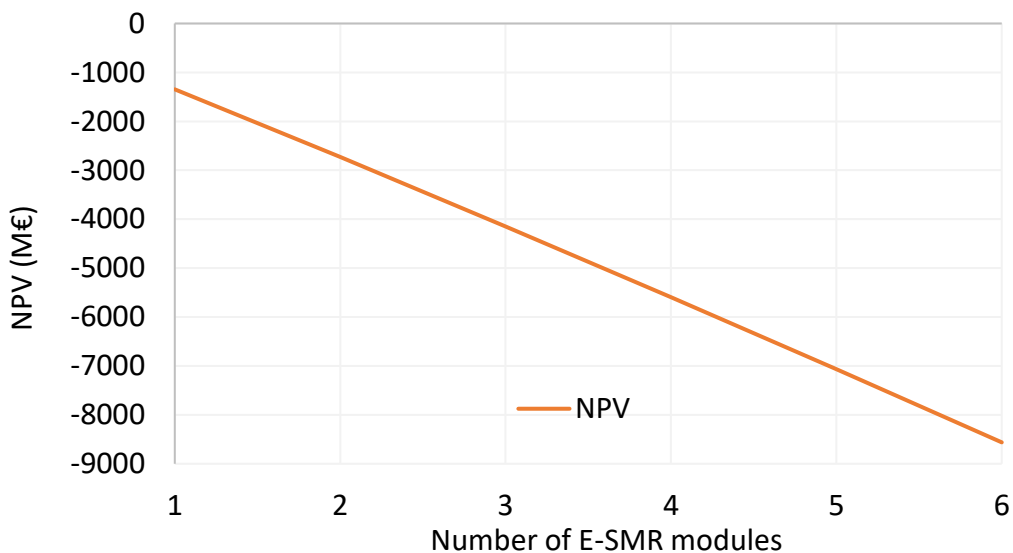
E-SMRs produce electricity when the electricity price exceeds operational costs. All operational costs are modelled in a single variable, including fixed annual costs like purchase of fuel. A better approach would be to model the fixed annual costs in a second variable, because the operational costs define when E-SMRs produce electricity. The model does not take into account the value of services electricity producers provide such as grid stability. The heat extraction rate is assumed to be 10 % for all E-SMR scenarios, however, the reactor maybe could be modified to run with higher heat extraction rate.

As shown in Figure 11 (a), E-SMRs generate electricity fairly consistently during the year, except in the summer when the power level drops. However, there are slight fluctuations throughout the year which come from the fact that E-SMR investments are modelled from district heating operator point of view. As noted earlier, E-SMRs cannot replace fossil production outside the city model. However, electricity generation in Finland was about 86 % carbon-free already in 2021 [20].



**Figure 11: (a) Cumulative electricity production and (b) electricity power level of E-SMR modules on one year (0h corresponding to the beginning of January).**

Even though E-SMRs generated lots of electricity in the Helsinki metropolitan area throughout the year, the E-SMR investments were unprofitable as the net present value of the investments turned out negative (See Figure 12) as E-SMR uses 90% thermal power for electricity production in the studied configuration, its business model is highly dependent on the electricity market and the size of the power system. Relatively low heat extraction rate and relatively low electricity prices in Finland make it difficult for E-SMRs to justify their huge electricity production capacity and capital requirements, from the viewpoint of a district heating operator. The simplifications explained earlier warrant for further research of a single E-SMR module specialized for district heating with higher heat extraction rate and modelling of electricity demand to study the electricity production capabilities more accurately. E-SMR with higher heat extraction rate is going to be studied in the sensitivity analyses, Task 3.3.



**Figure 12: NPV and IRR as a function of number of invested E-SMR modules.**

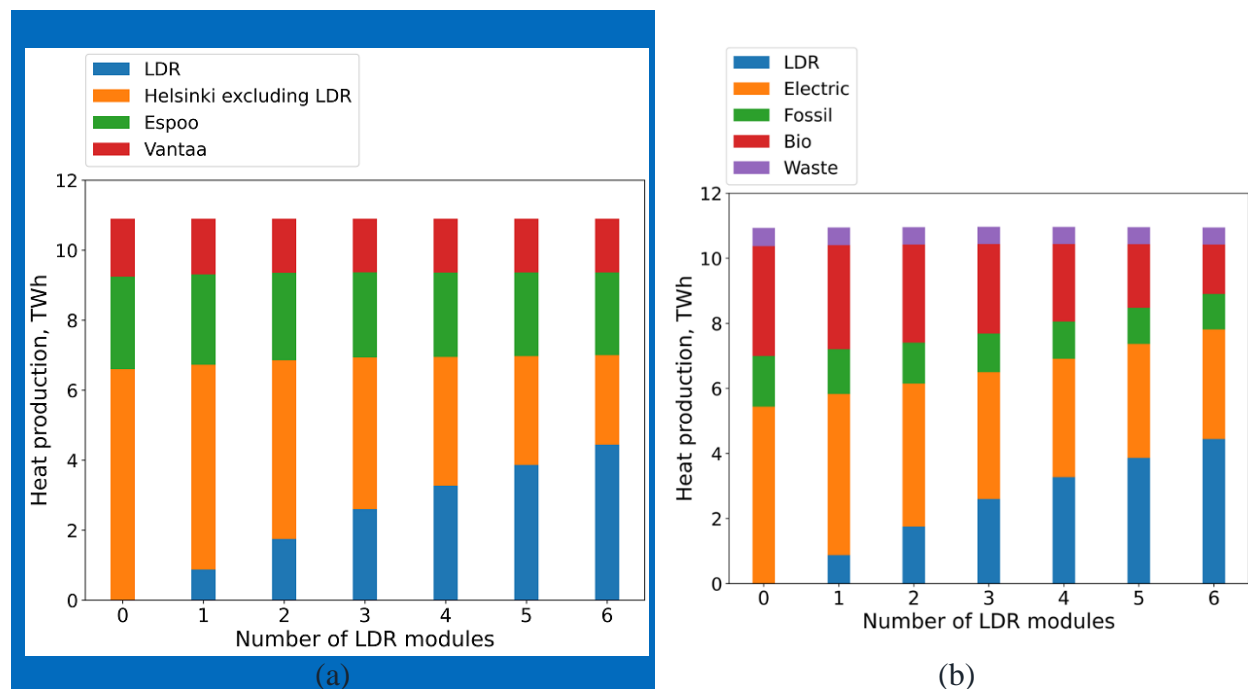
### 3.4 Scenario B – with LDR50 deployment in 2030

#### 3.4.1 Presentation of this case

In the second scenario of the Northern European case, integration of heat only boiler SMRs, LDR-50 district heating reactors, are studied. LDR-50 reactor units are deployed in varying amounts to the Helsinki metropolitan area to study their operability, profitability, and environmental impact in the region.

#### 3.4.2 Results

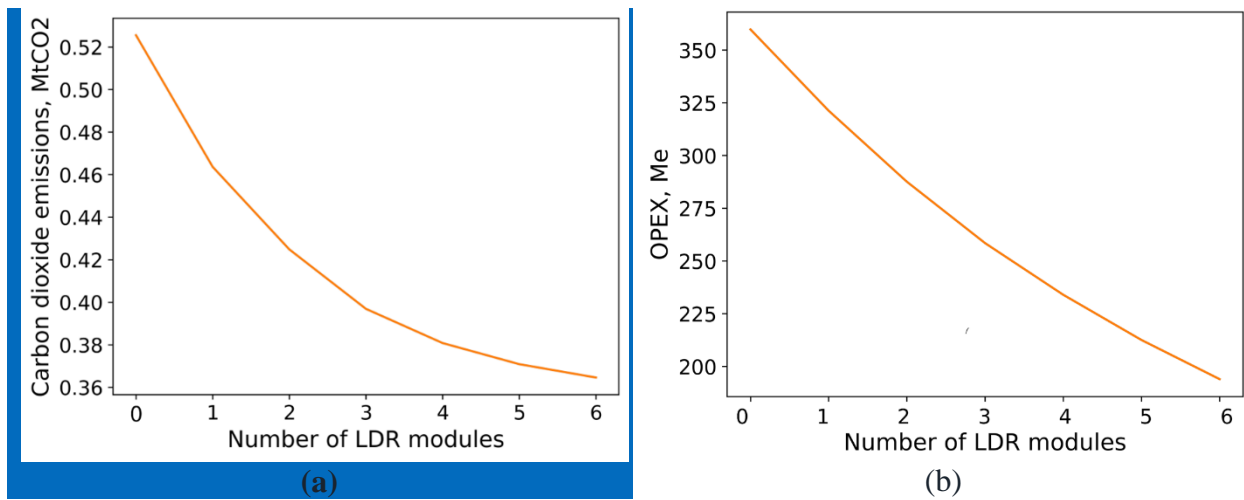
In this chapter, the results from LDR-50 scenario are presented. In the figures, each LDR-50 module consists of two reactor units which in total have thermal power output of 100 MW. Similarly as in the previous scenario, LDR-50 reactor modules replaces production mostly from Helsinki and slightly from Vantaa and Espoo. By fuel type, heat generation produced with heat pumps and electric boilers, fossil and bio fueled power plants decrease as more LDR modules are implemented to the region as seen from Figure 13.



**Figure 13: Yearly heat production by (a) area and (b) fuel type in the Helsinki metropolitan area.**

Figure 14 shows that the carbon dioxide emissions and operating expenses follow similar decreasing trend as in the E-SMR scenario. Fossil fueled power plants are replaced with carbon-free SMR technology, and thus, the carbon dioxide emissions and operating expenses in the area

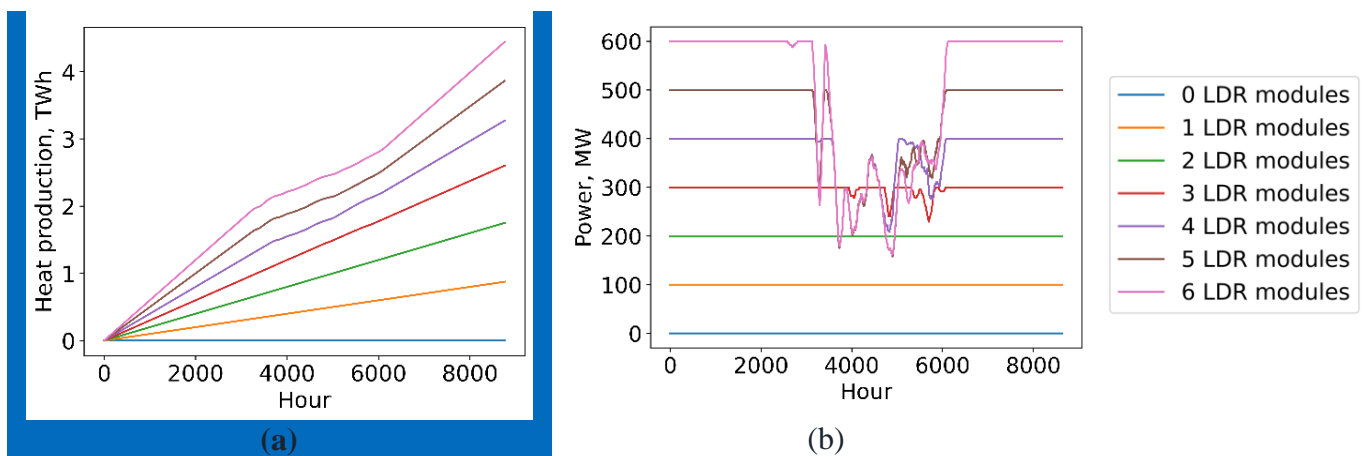
decrease. LDR modules are much smaller in their unit size so the decrease in energy system costs is much milder when compared to the E-SMR scenario.



**Figure 14: Yearly reduction of (a) CO<sub>2</sub> emissions and (b) energy system costs in the Helsinki metropolitan.**

Figure 15 shows that the LDR modules run at full power even in summer with the scenarios with one and two modules. With three modules, the reactor units have to perform some load following. In scenarios with more than 4 modules, reactor units need to do heavy load following, maintaining around 300 MW district heat production.

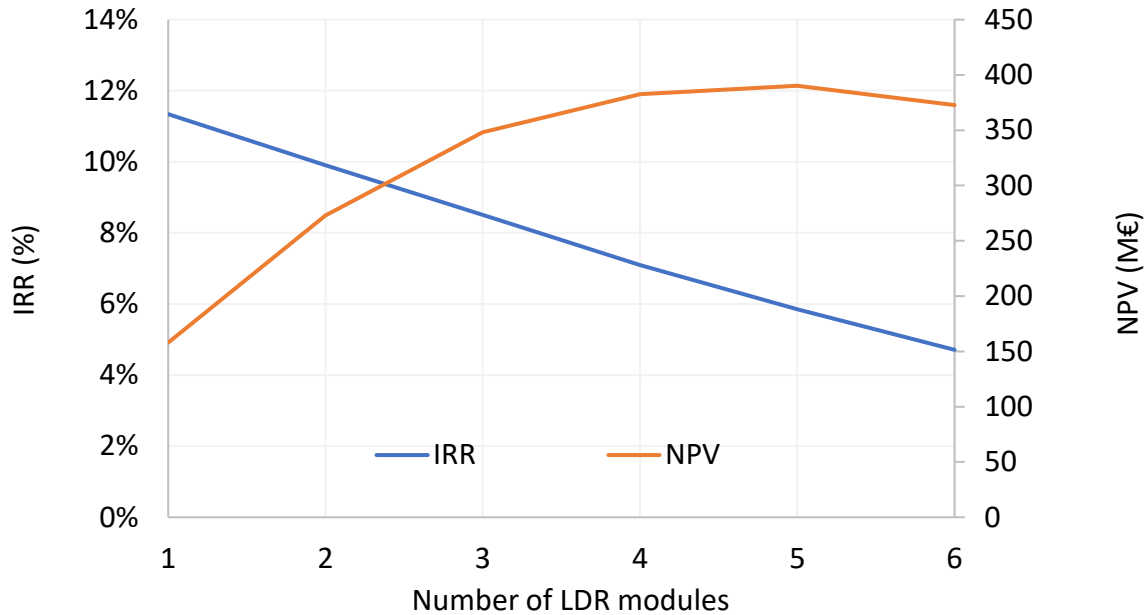
The curves do not follow identical pattern. This is because the Helsinki metropolitan area has big seasonal heat storages which contribute during the summer at different levels depending on the heat production capacity of LDR modules in each scenario. See Table 6 for modelled storage units.



**Figure 15: (a) Cumulative heat production and (b) power level of LDR modules.**



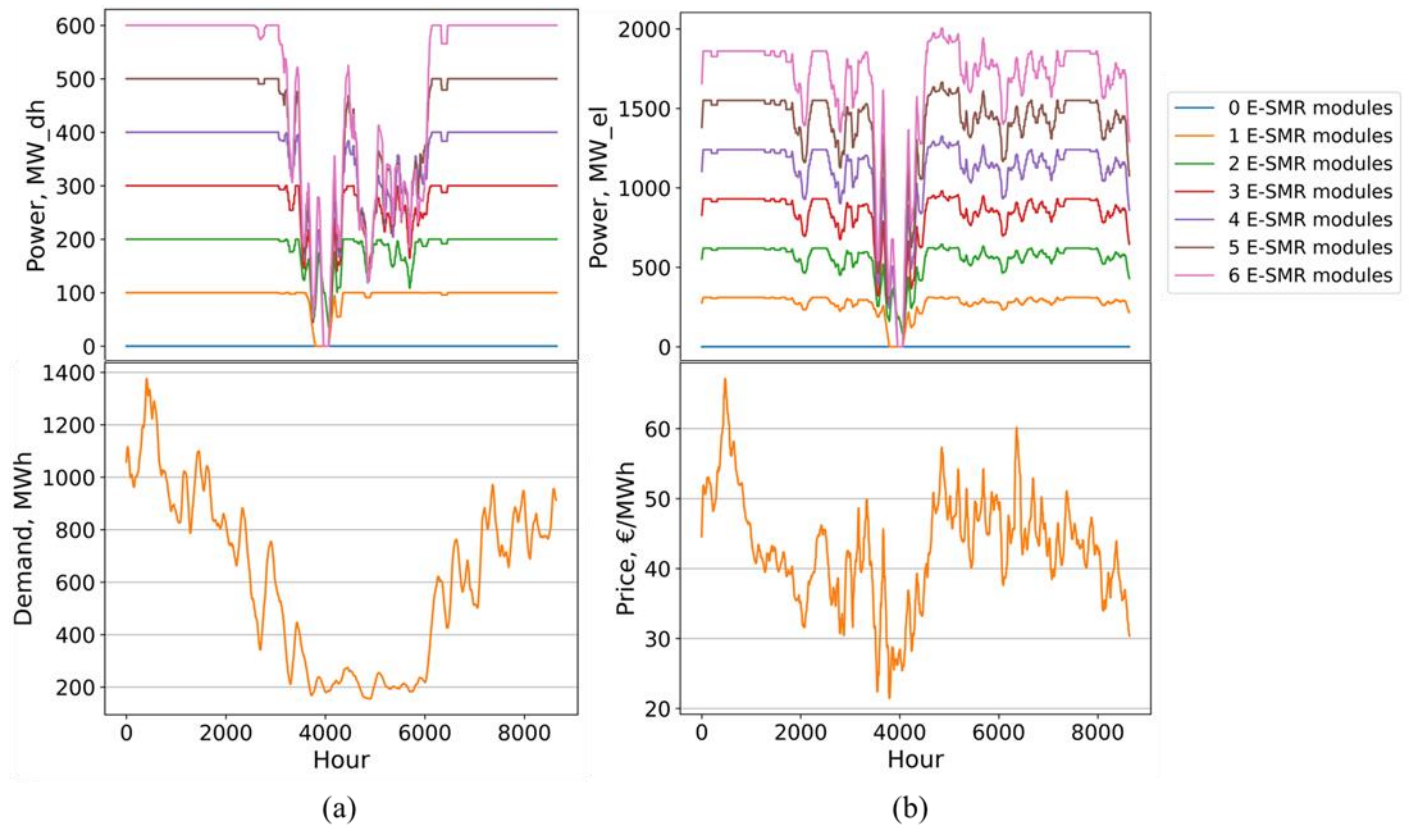
The results show LDR-50 modules to be profitable investments for DH generation. As can be seen from Figure 16, the internal rate of return is at its highest, 10 %, with 2 modules, decreasing to 4 % with 12 modules. With the LDR modules, net present value of the investments stays positive, implying financial gain. The simplifications explained for E-SMR scenario do not impact LDR-50 scenarios as heavily. LDR-50 is designed exclusively for heat production, so the electricity price modelling affects the results only indirectly through other units, such as heat pumps, in the modelled system.



**Figure 16: NPV and IRR as a function of invested LDR-50 modules.**

### 3.5 Conclusions

The studied reactor types showed promise in decarbonisation of the Helsinki metropolitan area. In both scenarios, carbon dioxide emissions dropped from 0.52 MtCO<sub>2</sub> to about 0.38 MtCO<sub>2</sub> with maximum amount of SMR modules implemented in the region. The heat demand in Finland fluctuates a lot between summer and winter, which limits the capacity of baseload units that can operate in the area. The electricity price in the Finnish market area changes quite a lot with the seasons. As seen from Figure 17, both the heat demand and the electricity price drop drastically in the summer, reducing income of energy producers. In the internal rate of return and net present value calculations, LDR-50 appears to be profitable investment for DH generation. The study and the used city-level model have few simplifications that needs to be pointed out, especially for the E-SMR scenario.



**Figure 17: Comparison of (a) thermal power and heat demand and (b) electric power and electricity price of E-SMR scenarios.**

The SMR investments modelled with a city-level model and studied from DH operator's point of view. In a DH system, the operator must produce heat, but can produce electricity or not. Instead of modelling the electricity demand, the city-level model uses electricity price based on the year 2019. The year 2019 had relatively low electricity prices and other historical time series years should be studied in the sensitivity analysis. Another simplification is the modelling of all SMR operational costs in a single variable. Running a nuclear power plant includes annual fixed costs and operational costs. The modelled E-SMR investments clump these costs into a single value. In conjunction, the E-SMR produces electricity when the electricity prices exceed the operational costs defined in the model. The model does not consider the value coming from services electricity producers provide such as stability to the grid.

With the important simplifications explained, E-SMRs generated lots of electricity throughout the year, but the profit after operating costs was not enough to cover the costs, from the viewpoint of a district heating operator; the capital requirements of E-SMR modules was too high to

generate enough profit with low electricity prices in the Finnish grids, and with low heat extraction rates.

A more detailed study of E-SMRs in the Helsinki metropolitan area would require modelling the annual fixed costs in another variable and modelling of the electricity balance in the Nordpool electricity market instead of the electricity price implemented in the city-level model. Additionally, the heat production capabilities of E-SMR were not explored thoroughly. The heat extraction rate was assumed to be 10% for all E-SMR investments. Alternative approach would be to implement a single E-SMR module specialized for producing district heat, for example, with a 40 % heat extraction rate. This approach will be studied further in Task 3.3 by increasing the heat extraction rate of E-SMR.

In summary, while E-SMRs offer promising solutions for decarbonisation of Helsinki Metropolitan area; further study will be required to assess accurately the gain brought by their deployment in this area. The Backbone city-level model is used to study new investments from the viewpoint of a district heating operator, so the impact of electricity price modelling is less affected to the study of LDR-50. LDR-50 is designed exclusively for heat generation to the district heating network; the study results indicated LDR-50 as a promising reactor type, by offering a carbon free and cost-effective solution for heat generation, emphasizing simplicity in its design.

It's important to note that both reactor designs are still under development and prone to many changes in the future. The findings of this study are based on many assumptions regarding the capital investment requirements, operation expenses, interest rates, electricity price, the rate of heat extraction from E-SMR to supply heat and construction time for example. In the next part of this study in Task 3.3, these technological factors, along with more economical factors such as fuel prices, operating costs, CO<sub>2</sub> credit prices will be investigated through sensitivity analyses.

## 4 Common assumptions for Southern and Central European cases for LCO and CO<sub>2</sub> intensity calculations

### 4.1 LCO calculation

There are three by-products delivered in both cases: electricity, hydrogen and heat.

TANDEM/deliverable D1.3 [1] presents the assessment of the Levelized Cost Of (LCO) electricity, heat and hydrogen. The levelized cost of each product is calculated by considering the sum of the CAPEX and the levelized OPEX (including energy costs) divided by the levelized amount of product produced during the project lifetime.

$$LCOE = \frac{CAPEX + \sum_{i=1}^n \frac{(OPEX_i + R_i + B_i)}{(1+k)^i}}{\sum_{i=1}^n \frac{E_{elec,i}}{(1+k)^i}} \quad LCOH = \frac{CAPEX + \sum_{i=1}^n \frac{(OPEX_i + R_i + B_i)}{(1+k)^i}}{\sum_{i=1}^n \frac{E_{heat,i}}{(1+k)^i}}$$

$$LCOH_2 = \frac{CAPEX + \sum_{i=1}^n \frac{(OPEX_i + R_i + B_i)}{(1+k)^i}}{\sum_{i=1}^n \frac{m_{H2,i}}{(1+k)^i}} \quad \text{with } R_i = \text{Replacement}_i \text{ and } B_i = \text{Buy}_i$$

Nevertheless, the calculations of TANDEM/deliverable D1.3 do not take into account the fact that there are three final products supplied at the same time: electricity, hydrogen and heat. The whole cost of the architecture is assigned to the calculation of a single product meaning that the LCO obtained with these calculation are maximum. This approach is called “**Full allocation**”. It indicates what the average revenue of one single product (either electricity, heat or hydrogen) price would have to be in order to recover the capital and operational expenditures of all components integrated in HES.

Another way to calculate more accurately the LCO is considering only components that directly contribute to the energy vector. Thus, first the Levelized Cost of Electricity (LCOE) is calculated by taking into account all the components involved in electricity production. The Levelized Cost of Heat (LCOH) is also calculated by taking into account all the components involved in heat production (SMR). In the case of a source generating both electricity and heat, its capital and operational expenditures are shared proportionally on the basis of the electricity and heat production ratio (including efficiency). Then, the Levelized Cost of Hydrogen (LCOH<sub>2</sub>) is deduced considering the contributions of the components involved for hydrogen production, including their electricity need as well as the contribution of the compressor and, if relevant, considering the LCOH for the contribution of components involved for hydrogen production (High Temperature Steam Electrolyser (HTSE)). It should be noticed that, in this case, the LCOE is used to calculate LCOH<sub>2</sub>. This approach is called “**Energy allocation**”. It indicates what the average revenue of one product (either electricity, heat or hydrogen) price would have to be in order to recover the capital and operational expenditures only of those components integrated in HES that are directly involved in the production of this product.

Furthermore, for both approaches three different methods for CAPEX evaluation are possible:

- **m1:** The residual value of each component is not considered at the end of 20-year economic lifetime.
- **m2:** The residual value of each component is proportional to the remaining operating lifetime e.g. CHP with operating lifetime of 40 years has residual value 50 % of CAPEX at the end of 20-year period. This residual value is subtracted from initial CAPEX.

- **m3**: The residual value of each component is proportional to the remaining operating lifetime and it is leveled.

To conclude for each case:

- ⇒ For the Southern European case: “**Energy allocation**” with **m3** method to take into account the residual value is used and presented.
- ⇒ For the Central European case: “**Energy allocation**” with **m1**, **m2** and **m3** methods to consider the residual value are presented. The most realistic (relevant) results are given by the m3 method. Therefore, the results obtained from this method will be presented as final economic evaluation and will be used for the comparison of all studied CEC scenarios.

#### 4.2 CO<sub>2</sub> intensity calculation

Regarding the CO<sub>2</sub> intensity of hydrogen, the issue is the same.

The CO<sub>2</sub> intensity of each product could be calculated by considering the sum of the grey emissions (linked to all other stages of life than use) divided by the project lifetime and the yearly direct emissions divided by the yearly amount of product produced. The Carbon Intensity (CI) of electricity, the one of hydrogen and the one of heat could be calculated that way:

$$CI_E = \frac{\frac{m_{CO_2, grey}}{20} + m_{CO_2, yearly}}{m_{Elec, yearly}} \quad CI_H = \frac{\frac{m_{CO_2, grey}}{20} + m_{CO_2, yearly}}{m_{th, yearly}} \quad CI_{H_2} = \frac{\frac{m_{CO_2, grey}}{20} + m_{CO_2, yearly}}{m_{H_2, yearly}}$$

These calculations lead again to maximum values. This approach is called “**Full CO<sub>2</sub> allocation**”.

Another way to calculate more accurately the carbon intensity of each product is considering only components that directly contribute to the energy vector. This approach is called “**Energy-based CO<sub>2</sub> allocation**”.

Thus, first the mean carbon intensity of electricity is calculated by taking into account all the components involved for electricity production. Then, the CO<sub>2</sub> intensity of hydrogen is deduced considering the mean carbon intensity of electricity and the contributions of the components involved for hydrogen production that all need electricity as well as the compressor. To be even more accurate, the CO<sub>2</sub> emissions due to the electricity consumption from the components involved for hydrogen production and from the compressor could be calculated using the hourly CO<sub>2</sub> intensity of electricity and not the mean carbon intensity of electricity.

For both cases, “**Energy-based CO<sub>2</sub> allocation**” is used and presented.

## 5 Southern European case

### 5.1 General presentation of the case

The Southern European case focuses on an industrial harbour, a well representative place of an energy hub due to the energy fluxes complexity that generally takes place there. It is supposed to be located at Fos-sur-Mer, a port in the South of France.

Due to the lack of available data on energy fluxes from the port at Fos-sur-Mer, whether on consumption or production, the idea was to build a virtual case located at Fos-sur-Mer, meaning that the location can be used to set the boundaries conditions like the grid electricity prices, the gas prices, PhotoVoltaic (PV) and wind potentials.

This virtual case illustrates low-carbon energy needs in terms of electricity, heat and hydrogen that could be issued by one or some industrials in the port. The needs for hydrogen are expected to be very huge so the case is built to have a balance between the loads, whether electric load or hydrogen load, and the sources, whether the Combined Cycle Gas Turbine (CCGT), one SMR, the PV field and the offshore wind farm. There is no thermal load, heat is only required to feed a HTSE to provide hydrogen. The case is thought in such a way that the loads can be fed without the help of CCGT.

A preliminary step is conducted in order to identify relevant architectures to study more in details. The methodology is described in chapter 5.3.

### 5.2 Assumptions

This chapter describes the base assumptions that are used in all the scenarios. Thus, there are some information about the general techno economic assumptions, about the perimeter of the study and the associated boundary conditions and a short description of the components that are modelled in this HES. Finally, there is also a focus on the methodology adopted to assess environmental impact, the LCO of electricity, heat, and hydrogen and the CO<sub>2</sub> intensity of electricity, heat and hydrogen.

#### 5.2.1 General techno-economic assumptions

In this study, the project lifetime considered is 20 years and the discount rate is 5% as the building of a French SMR would be supported by the French government. For components that have a longer technical lifetime than 20 years (60 years for E-SMR, 40 years for CCGT), a residual value is considered and deduced from the initial CAPEX. The exercise was done to compare the results obtained with this approach to a calculation over 60 years by taking into account replacements for components that have a technical lifetime lower than 60 years. The exercise shows that these

two approaches give similar results in this case (LCO difference within 5%). Finally, the lower the discount rate, the more important the future meaning that the share of OPEX becomes more important compared to the share of CAPEX.

Costs considered (CAPEX, variables costs) correspond to a forecast in 2035 and they are expressed in €<sub>2023</sub>. Thus, the economic results can be compared to current architectures without any additional assumption.

Furthermore, there is no maintenance period considered in the study.

Beyond the techno-economic results of the study case which depend on several assumptions, the project aims to provide tools and methods to study the techno-economic and environmental profitability of NHES.

### 5.2.2 General PERSEE assumptions

This study case is investigated implementing PERSEE, a tool developed by CEA. A detailed description of PERSEE is provided in TANDEM/deliverable D3.1 [1]. Thoughts are underway to make PERSEE open source.

The version of PERSEE used in this study is 3.9.3.

The solver used to solve the Mixed Integer Linear Programming (MILP) problem built to model the study case is the commercial solver CPLEX.

The gap is set to 0.5%, meaning that the solution found by the solver for each run is the first set of variables that:

- Satisfies the constraints.
- Gives a result for the objective function – which is minimize the total costs – that is higher than 99.5% of the optimal value.

Finally, to limit the duration of each run, a maximum duration is set to 36000 seconds that is to say 10 hours.

### 5.2.3 Boundary conditions

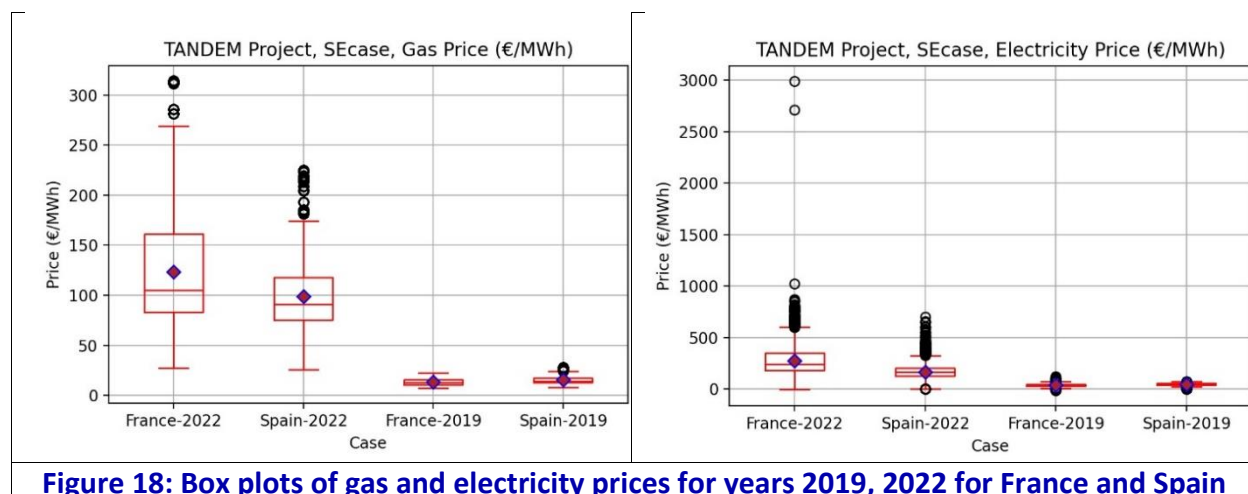
#### 5.2.3.1 Electrical, natural gas and heat networks

The HES modelled through PERSEE can:

- buy natural gas through a natural gas grid
- release electricity through an electricity network for free
- release heat through an heat network for free

In a first approach, to avoid unexpected behaviours, the electricity price is not considered in order to avoid installing PV only for selling electricity.

Figure 18 gives the box plots of the time series of gas price for France and Spain for years 2022 and 2019 on the left and of electricity price for France and Spain for years 2022 and 2019 on the right. Additionally to the box plot, the diamond is the average value and black dots represent extreme values that are not taken into account in the box plot.



**Figure 18: Box plots of gas and electricity prices for years 2019, 2022 for France and Spain**

Years 2019 and 2022 are very different due to the Ukrainian war that conducted to an increase of the gas prices. Thus, the French mean gas price increased from 13.5 €/MWh in 2019 to 123.5 €/MWh in 2022 and the Spanish mean gas price increased from 15.5 €/MWh to 98.9 €/MWh for the same period. Besides, the French mean electricity price was 39.5 €/MWh<sub>e</sub> in 2019 whereas it was 275.9 €/MWh<sub>e</sub> in 2022 and similarly in Spain, it went from 47.7 €/MWh<sub>e</sub> in 2019 to 167.5 €/MWh<sub>e</sub> in 2022.

In a first approach, only historical prices are taken into account (year 2019).

### 5.2.3.2 Electrical and hydrogen loads

The objective of the system is twofold: produce both hydrogen and electricity. The first objective is to feed a hydrogen load constantly throughout the year. The load profile is thus flat and the total amount of hydrogen that should be produced over one year is 72.3 ktons.

The second objective is to produce electricity that could be used for uses that are not modelled in PERSEE. Electricity could be used for water desalination or to supply local industry. In Dunkirk, the existing CCGT has a specific contract with ArcelorMittal feeding it about 1.7 GWh<sub>e</sub> over a year. The electrical load considered in a first approach is a constant load throughout the year of 75 MW<sub>e</sub> (657 GWh<sub>e</sub>). This kind of load could correspond to aggregated industrial needs. In industrial processes, the hydrogen need is often constant; considering the whole industrial area of Fos-sur-

Mer, due to the profusion of needs, a constant hydrogen need can be relevant. The value is chosen in such a way that the whole demand in electricity can be supplied without the CCGT.

Table 9 and Table 10 give a summary of the electrical consumption and of the heat consumption, respectively. Depending on the technology that is used to produce hydrogen – either a HTSE or a Low Temperature Electrolyser (LTE) or a Steam Methane Gas Reformer (SMGR) – the total electrical consumption and the heat consumption is not the same.

| Consumer  | Unit                  | Nominal electrical consumption |            |             |
|---|-----------------------|--------------------------------|------------|-------------|
| Electrical load   | MW <sub>e</sub>       | 75                             |            |             |
| H <sub>2</sub> production<br>(72.3 kton H <sub>2</sub> /year) | MW <sub>e</sub>       | HTSE                           | LTE        | SMGR        |
|   |                       | 306                            | 396        | 1.3         |
| H <sub>2</sub> Compressor                                     | MW <sub>e</sub>       | 18                             | 0          | 0           |
| <b>Total</b>  | <b>MW<sub>e</sub></b> | <b>399</b>                     | <b>471</b> | <b>76.3</b> |

**Table 9: Summary of the electrical consumptions**

| Consumer              | Unit             | Nominal heat consumption |
|-----------------------|------------------|--------------------------|
| HTSE heat consumption | MW <sub>th</sub> | <b>66</b>                |
| Heat losses           | %output from SMR | 5                        |

**Table 10: Summary of the heat consumptions**

The SMR alone (340 MWe for two units) cannot supply enough electricity to satisfy the total amount of electricity required by the consumers if the hydrogen is produced by a HTSE or by a LTE. To better understand the simulated case, Table 11 gives a summary of the electrical production based on the maximum installed capacity and load factors of each producer, which are described in 5.2.4.

| Producer configuration       | Unit            | Available nominal electrical power |
|------------------------------|-----------------|------------------------------------|
| SMR (base-load)+PV+Wind+CCGT | MW <sub>e</sub> | <b>860</b>                         |
| SMR (base-load)+PV+Wind      | MW <sub>e</sub> | <b>510</b>                         |

**Table 11: Summary of the electrical production**

Whatever the hydrogen production mean, the configuration including a SMR, a PV field and a wind farm can supply both the electrical load and the hydrogen load.

### 5.2.4 Techno-economic and environmental assumptions

In this chapter, tables give techno-economic and environmental main assumptions taken into account in the modelling of each component.

It should be noticed that a **negative value  $v$**  for a PERSEE parameter means that this parameter is an optimization variable. Thus:

- The variable is optimized between 0 and  $|v|$  (continuous variable and not integer variable)
- The parameter value is a result of the optimization

### 5.2.4.1 E-SMR

Except if it is specifically mentioned, in this study, the E-SMR works at full load in cogeneration mode of type 1 at a fix ratio of about 10% for heat recovery meaning that it delivers  $155 \text{ MW}_e$  and  $50 \text{ MW}_{th}$  per unit. At the beginning of the report, the Figure 1 shows the different cogeneration modes (1, 2 and 3) that can be modelled in PERSEE. In this study, a part is dedicated on investigating the flexibility aspects of such a HES and to do so, a sensitivity study on the cogeneration mode of the E-SMR is conducted. As described in section 2, the different possible operating modes of two units with 10% of heat recovery are the following:

- Cogeneration of type 1 at maximum capacity. Thus, the E-SMR does not offer any flexibility and delivers always  $155 \text{ MW}_e$  and  $50 \text{ MW}_{th}$ .
- Cogeneration of type 1 with load following. Thus, the E-SMR can adjust its output power staying on the line characterized by the two operating points ( $0 \text{ MW}_{th}$ ,  $0 \text{ MW}_e$ ) and ( $50 \text{ MW}_{th}$ ,  $155 \text{ MW}_e$ ) and a slope of  $\alpha$ .
- Cogeneration of type 3 with load following. Thus, the E-SMR can use the whole orange triangle to adjust its outputs.
- Cogeneration of type 2 with load following. Thus, the E-SMR can use the whole green triangle to adjust its outputs. For this case, the slope  $-\beta$  and the other point of the line must be defined as there is no preliminary information on this mode.

Each of these cogeneration modes can be used separately but there is also an option to optimize the cogeneration mode.

In order to better understand the E-SMR modelling in PERSEE, the pre-calculations to define among other things  $\alpha$ ,  $\beta$  and  $\zeta$  are presented below.

$$\overline{P_{th}} = 540 \text{ MW}_{th} \text{ and } \overline{P_{el}} = 170 \text{ MWe} \text{ for one unit.}$$

By taking an assumption on heat of recovery  $\eta_{th} = 9.26\%$ , it results in  $\overline{P_{th,bp}} = 50 \text{ MW}_{th}$  and it is assumed that due to the heat recovery, there is a small decrease of the electricity output in such a way that  $\overline{P_{el,bp}} = 155 \text{ MWe}$ . It results in  $\eta_{el} = 28.7\%$ .

- For type 1 cogeneration,  $\alpha$  needs to be calculated:  $\alpha = \frac{\overline{P_{el,bp}}}{\overline{P_{th,bp}}} \approx 3.1$
- For type 3 cogeneration,  $\zeta$  needs to be calculated:  $\zeta = -\frac{\overline{P_{el}} - \overline{P_{el,bp}}}{\overline{P_{ch,min}} - \overline{P_{th,bp}}} \approx -\frac{340 - 310}{0 - 100} \approx 0.3$
- For type 2 cogeneration,  $\beta$  needs to be calculated:  $\beta = -\frac{\overline{P_{el,bp}} - \overline{P_{el,min}}}{\overline{P_{th,bp}} - \overline{P_{th}}}$

The point  $M_{TH}$  needs to be defined. In order to investigate whether this green triangle can be interesting for such a HES, point  $M_{TH}$  can be defined as (1080 MWth, 0 MWe) meaning that the SMR produces only heat.

Furthermore, PERSEE needs also the maximal power defined as the sum of  $\overline{P_{el,bp}}$  and  $\overline{P_{th,bp}}$  so 205 MW for one unit. The whole reasoning is linear and so transposable to two units. Finally, according to the level of detail of the SMR modelling, Table 12 details the technical settings taken into account in PERSEE. Economic and environmental parameters are described in Table 2 and Table 3, at the beginning of the report.

| Parameter name                      | Unit | Value   |
|-------------------------------------|------|---------|
| Maximum power <sup>5</sup>          | MW   | -410    |
| Efficiency Output 1 (heat recovery) | -    | 0.09258 |
| Efficiency Output 2 (electricity)   | -    | 0.287   |

**Table 12: Technical parameters of E-SMR**

#### 5.2.4.2 CCGT

The CCGT is inspired from CCGT that currently exists at Dunkirk but the maximal power is lower in order to be closer to the SMR electrical output power. The CCGT does not produce heat. Table 13, Table 14 and Table 15 gather the techno-economic and environmental data that are taken into account in PERSEE [26][27].

| Parameter name | Unit | Value |
|----------------|------|-------|
| Maximal power  | MW   | -350  |
| Efficiency     | %    | 0.53  |

**Table 13: Technical parameters of CCGT**

| Parameter name  | Unit               | Value  |
|-----------------|--------------------|--------|
| Design lifetime | years              | 30     |
| CAPEX           | €/MW <sub>e</sub>  | 903000 |
| Variable cost   | €/MWh <sub>e</sub> | 5.6    |

**Table 14: Economic parameters of CCGT**

CAPEX includes the equipment and the dismantling.

| Parameter name   | Unit                                     | Value                |
|------------------|--|----------------------|
| Grey emissions   | kg CO <sub>2</sub> eq/MW                 | -                    |
| Direct emissions | kg CO <sub>2</sub> eq/kg CH <sub>4</sub> | 2.8464 (Gas burning) |

**Table 15: Environmental parameters of CCGT**

<sup>5</sup> The maximum power is the result of the optimization between 0 and 410 MW.

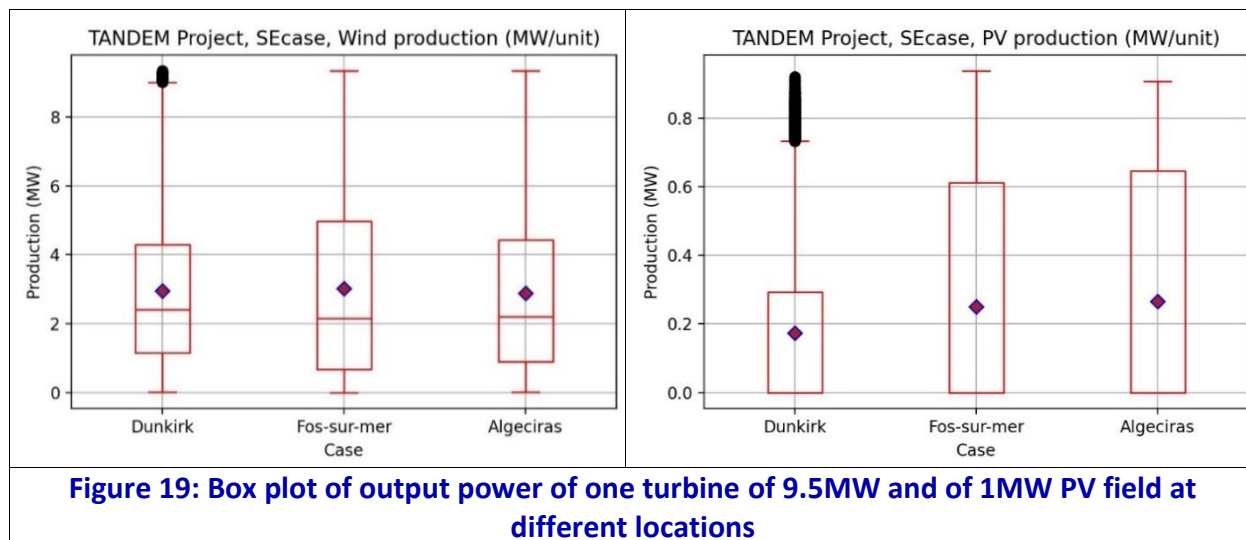
From IPCC [45], the direct emission value is between 410 kg CO<sub>2</sub> eq/MWh<sub>e</sub> and 650 kg CO<sub>2</sub> eq/MWh<sub>e</sub> for CCGT. For comparison, if we consider the PCI of CH<sub>4</sub> (11.86 kWh/kg CH<sub>4</sub>) and the efficiency taken into account (53%) and the direct emissions of CH<sub>4</sub>, it leads to about 453 kg CO<sub>2</sub> eq/MWh<sub>e</sub>.

In a first approach, the CCGT is not equipped with a Carbone Capture and Storage (CCS) component. This assumption may be criticisable and thus a sensitivity study could be conducted in Task 3.3 to consider it. It would change the techno-economic and environmental assumptions for the CCGT.

#### 5.2.4.3 Wind farm & PV

For the wind farm, the technology considered is floating offshore wind turbine and especially, the model taken into account for the computation of the power potential is “Vestas V164 9.5MW”. This choice was made as it is the most suitable technology for the reference location Fos-sur-Mer which is near from the Mediterranean Sea. The techno-economic and environmental data concern a farm with a power less than 100MW for France. For the PV field, the technology considered is fix utility based on monocrystalline technology, slope and azimuth optimized and 14% of system losses.

To compute the time series of electricity production from the floating offshore wind farm, renewables ninja [28] was used at three different locations: Dunkirk, Fos-sur-Mer and Algeciras (Spain). In the same way, the time series of electricity production from the PV field was computed owing to PVGIS [29]. Figure 19 presents the box plots of the time series obtained with on the left, the ones of the wind production and on the right the ones of the PV production. Additionally to the box plot, the diamond is the average value and black dots represent extreme values that are not taken into account in the box plot.



**Figure 19: Box plot of output power of one turbine of 9.5MW and of 1MW PV field at different locations**

Another indicator that is worth calculating it the load factors. Table 16 gives the load factor obtained at each location.

|                           | Dunkirk | Fos-sur-Mer | Algeciras |
|---------------------------|---------|-------------|-----------|
| Wind farm Load factor (%) | 31.0    | 31.7        | 30.4      |
| PV field Load factor (%)  | 17.2    | 25.0        | 26.5      |

**Table 16: Load factors of floating offshore wind farm and of PV field at different locations**

From a statistic point of view, the three locations are quite close regarding the wind production. The output power at Dunkirk has a variation range slightly smaller than the one at Fos-sur-Mer. Nevertheless, considering the PV production, Dunkirk is quite different from Fos-sur-Mer and Algeciras. The PV potential is really lower at Dunkirk than at Fos-sur-Mer and at Algeciras.

Finally, according to the level of detail of the wind farm modelling, the techno-economic data of Table 17 and Table 18 are used and Table 20 and Table 21 describe the techno-economic data used in the modelling of the PV field. Table 19 and Table 22 give the environmental data that are used to configure the wind turbine [30][31][32][33][34][35][36][37][38][39][40][41][42][43][44] and the PV field respectively.

| Parameter name     | Unit | Value |
|--------------------|------|-------|
| Nominal power      | MW   | 9.5   |
| Number of turbines | -    | -80   |

**Table 17: Technical parameters of floating offshore wind farm**

Today, there are two ongoing projects of offshore wind farms of 250 MW<sub>e</sub> each. The potential electricity production from offshore wind farm composed of 80 turbines of 9.5 MW<sub>e</sub> (resulting in an installed capacity of 760 MW<sub>e</sub>) is considered.

| Parameter name  | Unit         | Value   |
|-----------------|--------------|---------|
| Design lifetime | years        | 25      |
| CAPEX           | €/MW         | 2905000 |
| OPEX            | %/CAPEX/year | 2.3     |

**Table 18: Economic parameters of floating offshore wind farm**

CAPEX includes the CAPEX of the wind turbine, the CAPEX of the installation (preliminary studies, building permit, transportation, sea cables and so on), the CAPEX of the grid connection, the CAPEX of dismantling and a provision for contingencies.

| Parameter name                   | Unit                                   | Value |
|----------------------------------|--|-------|
| Direct CO <sub>2</sub> emissions | kg CO <sub>2</sub> eq/MWh <sub>e</sub> | 22.3  |

**Table 19: Environmental parameters of floating offshore wind farm**

From IPPC [45], the direct CO<sub>2</sub> emission value is between 8 kg CO<sub>2</sub> eq/MWh<sub>e</sub> and 35 kg CO<sub>2</sub> eq/MWh<sub>e</sub> for wind offshore.

| Parameter name     | Unit | Value |
|--------------------|------|-------|
| Installed capacity | MW   | -200  |

**Table 20: Technical parameters of PV field**

TotalEnergies inaugurated the largest French PV field with trackers in La Feuillane near Fos-sur-Mer with an installed capacity of 33 MW<sub>e</sub>. A potential electricity production from PV field of 200 MW<sub>e</sub> is considered in the study to take into account the increase of PV in France.

| Parameter name  | Unit         | Value  |
|-----------------|--------------|--------|
| Design lifetime | years        | 20     |
| CAPEX           | €/MW         | 520000 |
| OPEX            | %/CAPEX/year | 2.3    |

**Table 21: Economic parameters of PV field**

CAPEX gathers both the CAPEX of the module and the one of the Balance Of System (BOS).

| Parameter name | Unit                     | Value  |
|----------------|--------------------------|--------|
| Grey emissions | kg CO <sub>2</sub> eq/MW | 912000 |

**Table 22: Environmental parameters of PV field**

The grey emissions highly depends on the place where the components are built. Another parameter that have a significant impact on the value is the efficiency. In this study, the value taken into account is for a stack made in China with the current efficiency of the market.

From IPPC [45], the direct CO<sub>2</sub> emission value is between 18 kg CO<sub>2</sub> eq/MWh<sub>e</sub> and 180 kg CO<sub>2</sub> eq/MWh<sub>e</sub> for PV utility. For comparison, if we consider that the PV field is used for 20 years with a load factor of 25%, it leads to about 21 kg CO<sub>2</sub> eq/MWh<sub>e</sub>.

#### 5.2.4.4 High Temperature Steam (HTSE) and Low temperature electrolyzers (LTE)

Two technologies of electrolyzers are considered in the study. For LTE, PEM technology was chosen. For HTSE, Solid Oxide Electrolyser Cell (SOEC) technology was selected.

In a first approach, ageing is not considered in the study, only stack replacement is taken into account.

Table 23 and Table 24 provide the techno-economic data that are used in the modelling and Table 25 gives the environmental data [46][47][48][49][50][51][52].

| Parameter name          | Unit                                 | HTSE Value | LTE Value |
|-------------------------|--------------------------------------|------------|-----------|
| Nominal power           | MW                                   | -500       | -600      |
| Minimal power           | %P <sub>nom</sub>                    | 60         | 0.05      |
| Operating pressure      | bar                                  | 1          | 30        |
| Heat consumption        | kWh <sub>th</sub> /kg H <sub>2</sub> | 8          | -         |
| Electricity consumption | kWh <sub>e</sub> /kg H <sub>2</sub>  | 37         | 48        |

**Table 23: Technical parameters of HTSE and LTE**

It should be noticed that water consumption was not taken into account. The water consumption for both technologies is around 18 kg H<sub>2</sub>O/kg H<sub>2</sub>.

The electricity consumption corresponds to the amount of electricity that is needed to produce 1kg of H<sub>2</sub> meaning that it gathers both the stack consumption and the auxiliary consumption. It is based on PCI H<sub>2</sub> equals to 33.33 kWh/kg H<sub>2</sub>. The heat consumption is used to bring water to operating conditions (steam).

| Parameter name         | Unit              | HTSE Value | LTE Value |
|------------------------|-------------------|------------|-----------|
| Design lifetime        | years             | 20         | 20        |
| CAPEX                  | €/MW <sub>e</sub> | 780000     | 750000    |
| OPEX                   | %/CAPEX/year      | 2.5        | 2.5       |
| Stack replacement cost | €/MW              | 166250     | 250000    |
| Stack lifetime         | hours             | 50000      | 80000     |

**Table 24: Economic parameters of HTSE and LTE**

The CAPEX takes into account the CAPEX of the electrolyser and the CAPEX of the installation. A sensitivity study could be conducted on the CAPEX of PEM electrolyser.

| Parameter name | Unit                     | HTSE Value | LTE Value |
|----------------|--------------------------|------------|-----------|
| Grey emissions | kg CO <sub>2</sub> eq/MW | 620        | 1570      |

**Table 25: Environmental parameters of HTSE and LTE**

The given values correspond to electrolyzers made in Europe.



### 5.2.4.5 Steam Methane Gas Reformer (SMGR)

A Steam Methane Gas Reformer is modelled to produce hydrogen. Inlet products are methane, water and electricity. Table 26, Table 27 and Table 28 give respectively the technical, economic and environmental parameters used in the simulations [53] and :

| Parameter name          | Unit                  | Value |
|-------------------------|-----------------------|-------|
| Maximum capacity        | kg H <sub>2</sub> /h  | 8257  |
| Outlet pressure         | bars                  | 30    |
| SMGR Efficiency         | -                     | 0.6   |
| Electricity consumption | kWh/kg H <sub>2</sub> | 0.15  |

**Table 26: Technical parameters of SMGR**

| Parameter name | Unit                      | Value  |
|----------------|---------------------------|--------|
| Lifetime       | year                      | 20     |
| CAPEX          | €/MW H <sub>2</sub> (PCI) | 910000 |
|                | €/(kg H <sub>2</sub> /h)  | 30330  |
| OPEX           | %CAPEX/year               | 4.7    |

**Table 27: Economic parameters of SMGR**

| Parameter name   | Unit                                    | Value |
|------------------|---|-------|
| Grey emissions   | kg CO <sub>2</sub> eq/MW                | -     |
| Direct emissions | kg CO <sub>2</sub> eq/kg H <sub>2</sub> | 9     |

**Table 28: Environmental parameters of SMGR**

In a first approach, the SMGR is not equipped with a CCS component. It could be considered in a sensitivity study. It would change the techno-economic and environmental assumptions for the SMGR.

### 5.2.4.6 Hydrogen compressor

A hydrogen compressor is modelled to increase the pressure at the HTSE hydrogen outlet from 1 to 30 bars to store hydrogen. The compressor is not used for the LTE and SMGR as the outlet pressure is 30 bars. Table 29 and Table 30 give respectively the main technical and economic characteristics of the compressor. The grey contribution to environmental impacts is neglected as over 20 years, the contribution of direct emissions due to electricity consumption is responsible for the main part of the CO<sub>2</sub> emissions. The imposed hydrogen load would require several compressors in reality but for optimization purposes, a global compressor is modelled to take into account the electrical power and the associated CAPEX and OPEX. PERSEE tool calculates the electrical power using the following model [55], [56], [57] and [58].

$$P = \frac{1}{\eta_{is}} \cdot n \cdot \dot{m} \cdot c_p \cdot T_1 \cdot \left( \tau^{\frac{\gamma-1}{n \cdot \gamma}} - 1 \right)$$

the electrical power [W], the hydrogen mass flowrate [kg/s], the compression efficiency (taking into account the isentropic and motor efficiencies), the hydrogen thermal capacity (at constant pressure) [J/kg/K], the inlet temperature [K], the compression rate, the number of stages, the isentropic coefficient.

| Parameter name   | Unit                               | Value        |
|--|------------------------------------|--------------|
| Inlet pressure   | bars                               | 1            |
| Outlet pressure  | bars                               | 30           |
| Compression rate   | Outlet pressure/<br>Inlet pressure | 30           |
| Number of stages   | -                                  | 3            |
| Hydrogen mass flowrate   | kg/h                               | -20000       |
| Hydrogen thermal capacity  | J/kg/K                             | 14400        |
| Compression efficiency =<br>Motor efficiency*Isentropic efficiency | -                                  | 0.63=0.9*0.7 |
| Isentropic coefficient   | -                                  | 1.4          |
| Inlet temperature  | K                                  | 293          |

**Table 29: Technical parameters of the compressor**

For information, the electricity consumption for a hydrogen mass flow rate of 8257 kg H<sub>2</sub>/h is 17.82 MWh.

| Parameter name | Unit        | Value |
|----------------|-------------|-------|
| Lifetime       | -           | 10    |
| CAPEX          | €/kW        | 1000  |
| OPEX           | %CAPEX/year | 1     |

**Table 30: Economic parameter of the compressor**

#### 5.2.4.7 Hydrogen storage

A hydrogen storage is considered to give more flexibility to the system. Table 31 and Table 32 give respectively the technical and economic parameters of the hydrogen storage used in the simulations [55]. Hydrogen is assumed to be stored at Fos-sur-Mer location owing to tanks at a pressure of 30 bar. An additional compressor to store the hydrogen at 200 bar could have been considered in the study. Hydrogen losses are not considered as well as the auxiliary electricity consumption of the storage.

Furthermore, environmental impacts (grey, direct and indirect) are neglected.

| Parameter name   | Unit              | Value   |
|------------------|-------------------|---------|
| Maximum capacity | kg H <sub>2</sub> | -160000 |
| Pressure         | bar               | 30      |

**Table 31: Technical parameters of the hydrogen storage**

| Parameter name | Unit | Value |
|----------------|------|-------|
|----------------|------|-------|

|          |                     |     |
|----------|---------------------|-----|
| Lifetime | year                | 20  |
| CAPEX    | €/kg H <sub>2</sub> | 490 |
| OPEX     | %CAPEX/year         | 1.5 |

**Table 32: Economic parameters of the hydrogen storage**

Another option to store such amount of hydrogen would be salt caverns. There are some near from Fos-sur-Mer. This option may be more realistic but in this case, the pipes to transport the hydrogen to and from the salt caverns need to be considered (from a techno-economic point of view).

#### 5.2.4.8 Thermal energy storage

A heat storage is considered in the study to offer the possibility to shift the production of heat from the SMR and the consumption of heat from the HTSE. The technology selected for the storage of thermal energy is a sensible two-tank heat storage system and employing thermal oil as a sensible medium. Table 33 and Table 34 give respectively the technical and economic parameters of the thermal energy storage used in the simulations. The values are based on PEPS5 study [59].

Furthermore, environmental impacts (grey, direct and indirect) are neglected.

| Parameter name                                  | Unit              | Value |
|---|-------------------|-------|
| Maximum storage capacity                        | MWh <sub>th</sub> | -264  |
| Number of hours needed to full charge/discharge | hour              | 4     |
| Self-discharge                                  | %/day             | 1     |

**Table 33: Technical parameters of the thermal energy storage**

It is assumed that the charge power is sized in such a way that the number of hours needed to completely charge the storage is 4 hours.

| Parameter name | Unit                | Value |
|----------------|---------------------|-------|
| Lifetime       | year                | 20    |
| CAPEX          | €/MWh <sub>th</sub> | 63750 |
| OPEX           | %CAPEX/year         | 1     |

**Table 34: Economic parameters of the thermal energy storage**

### 5.2.5 Focus on environmental calculation

A general description of the Life Cycle Assessment (LCA) is provided in Annex 9.1.

In PERSEE, the user can consider different impact categories. The available categories are the ones from Environmental Footprint (EF) v3.0 method [60] that gathers 16 categories among which there are Climate change/Global Warming Potential (GWP100), Ozone depletion/Ozone Depletion Potential (ODP), Land use/Soil Quality Index (LU), Water use/User Deprivation Potential (WU) for instance.



In this study, only Climate change/Global Warming Potential (GWP100) is taken into account. In PERSEE, the user can fill two kinds of emissions:

- The first one is the indirect or grey emissions, linked to the construction of a component and the unit in kg CO<sub>2</sub> eq/{Installed capacity unit}.
- The second one is the direct emissions, linked to the use of the component. Main data are coming from the French ADEME “EMPREINTE” data base, giving the emission factors for carbon inventory for facilities [62].

Environmental impacts and GWP100 are evaluated through the carbon dioxide equivalent (the carbon intensity, CO<sub>2</sub> eq) parameter. The following figure compares carbon intensity to selected thresholds [61]. For this project, the calculated CO<sub>2</sub> emissions and the CO<sub>2</sub> intensity of hydrogen are compared with existing data [61] and in particular with the Hydrogen Europe source, as shown in Figure 20:

- The CERTIFHy™ threshold for low-carbon hydrogen: at 4.4 kg CO<sub>2</sub> eq/kg H<sub>2</sub>.
- The EU Taxonomy threshold for sustainable hydrogen manufacturing: 3 kg CO<sub>2</sub> eq/kg H<sub>2</sub>.

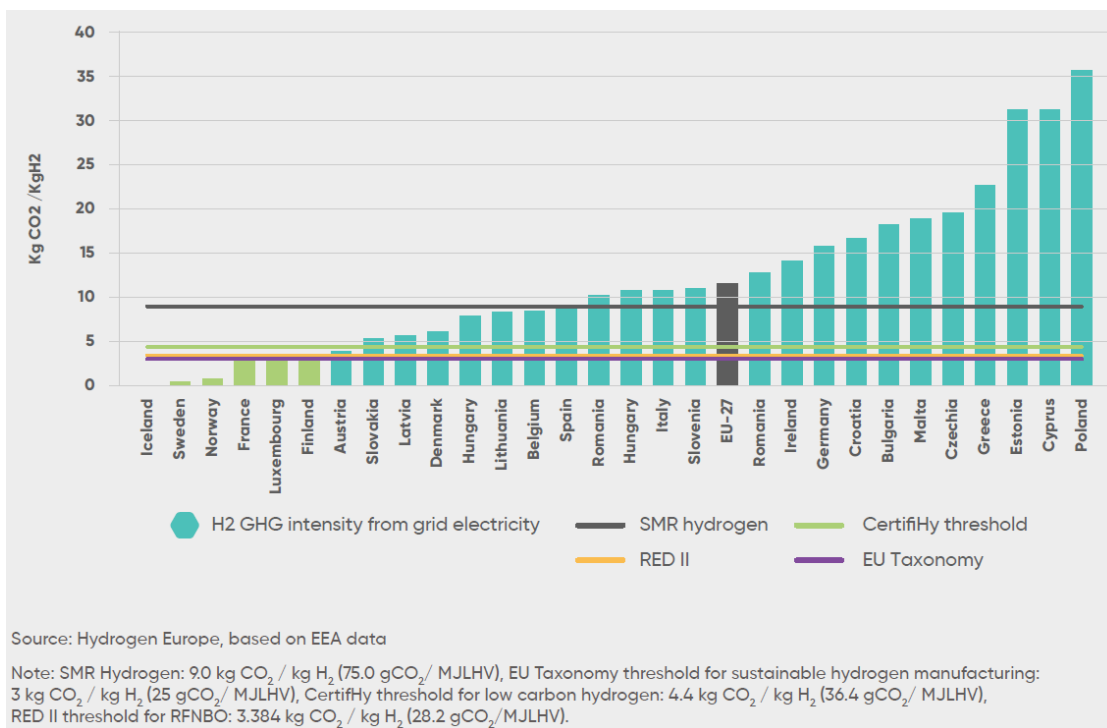


Figure 20: Carbon intensity of hydrogen for selected benchmarks [61]<sup>6</sup>

<sup>6</sup> In the picture, SMR means Steam Methane Reformer

### 5.3 Methodology adopted to analyse the decarbonisation of the system

The main objective is to answer to the question:

**“How the energy system and the hydrogen production can be decarbonized?”**

All the possible components are modelled with a complete technical, economic and environmental data set.

The whole architecture, studied with PERSEE, allows to produce hydrogen by different means.

- Today (2035), the hydrogen is mainly produced by captive reforming that is to say from steam reforming, partial oxidation, gasification and auto-thermal reforming of fossil fuels that is subsequently used onsite. A SMGR component is modelled in the architecture with a methane (CH<sub>4</sub>) input. In this frame, CCS is not considered.
- Another way to produce hydrogen is water electrolysis (2035, 2050) either by a LTE, based on a PEM technology or a HTSE. It can be noticed that HTSE needs a compressor to reach a 30bar pressure and the SMGR and LTE not. HTSE needs also thermal energy (140 °C at minimum) as input; electrical heaters and (or) thermal energy coming from the SMR and thermal storage are modelled.

In the same idea, different ways have been modelled to produce electricity needed for insuring the electrical load and to feed the auxiliary components (SMGR, electrolyzers, compressors, heaters):

- A CCGT is often already (2035) installed in harbour to produce electricity with methane input.
- In the future (2035, 2050), SMR and renewable energies (PV, Wind turbines) will be considered.

In order to analyse this scenario devoted to the decarbonisation of hydrogen production, a study is conducted to find optimal (NPV optimizations with technical and economic data) architectures (and the associated sizings of the components) where CO<sub>2</sub> emissions are limited and constrained. Optimizations are based on one year with a time step of 1h.

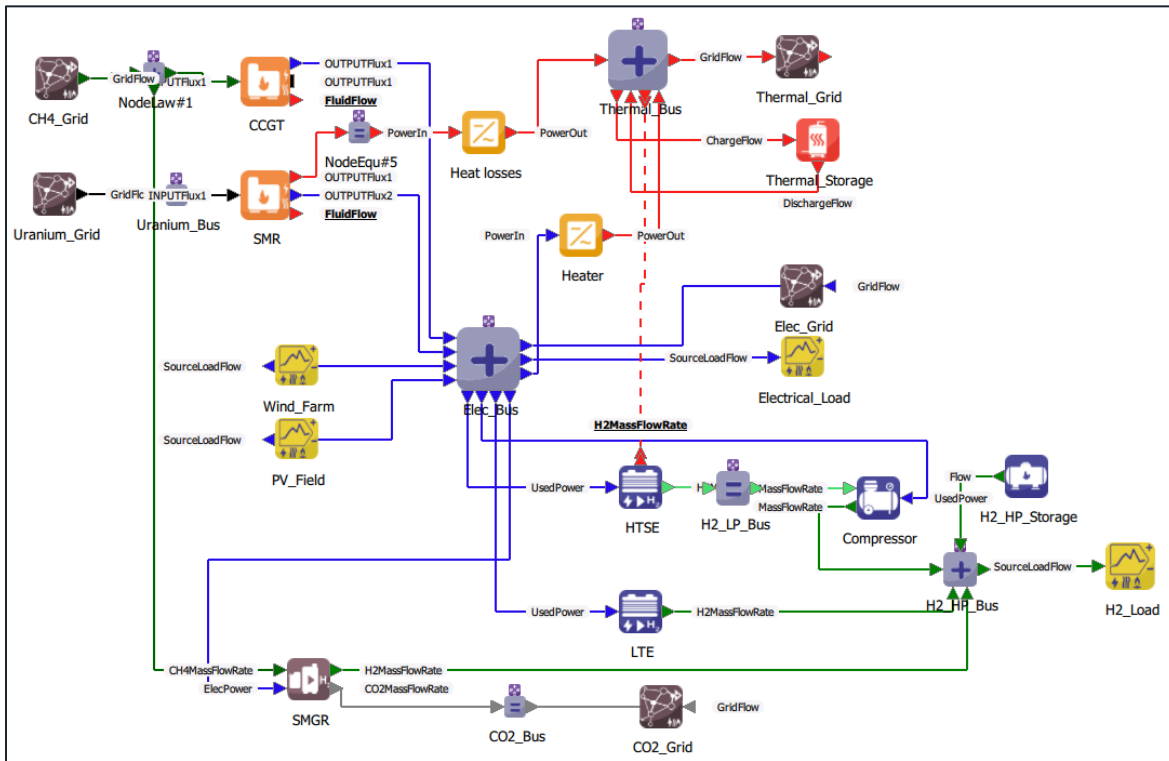
This study is run for the Fos-sur-Mer configuration; the PV and wind profiles are detailed in section 5.2.4.3 when the electrical and natural gas network price are given in section 5.2.3.1.

At the end and as defined in the frame of the TANDEM project, three different scenarios must be more investigated.

- The reference scenario, “Low SMR deployment” where SMR are little or no deployed in 2035. The architecture does not contain any SMR.

- This “High SMR deployment” scenario where SMR are deployed in 2035. For this second case, the architecture contains one SMR.
- Finally, the last scenario of 2050 follows the trend of 2035 “High SMR deployment” and results in an architecture with two SMR.

Figure 21 shows the global architecture as it was modelled in PERSEE.



**Figure 21: Global architecture**

**5.4 Results of the study to find optimal architectures under CO<sub>2</sub> emissions constraint**

14 (from 0 to 13) runs and optimisations have been conducted; components have to be sized by taking into account realistic and relevant maximum capacities.

The Table 35 gives the mains results of the optimisations:

- The total amount of CO<sub>2</sub> emissions in the energy system.
- The total costs.

Blue cells in the table give the presence of each component in the energy system. Green cells on the total amount of CO<sub>2</sub> emissions correspond to architectures where the carbon intensity of hydrogen is below limits given by the CERTIFHy™ and European taxonomy references (see section 5.2.5).

| Run | Total CO <sub>2</sub> emissions (ktons/year) | Total costs (M€) | CCGT | SMGR | PV | SMR | WIND | HTSE | LTE | H <sub>2</sub> Storage |
|-----|--|------------------|------|------|----|-----|------|------|-----|------------------------|
| -1  | 984.839                                      | 1235.93          |      |      |    |     |      |      |     |                        |

|    |          |         |  |  |  |  |  |  |  |  |
|----|----------|---------|--|--|--|--|--|--|--|--|
| 0  | 894.6599 | 1217.41 |  |  |  |  |  |  |  |  |
| 1  | 847.799  | 1463.60 |  |  |  |  |  |  |  |  |
| 2  | 795.7881 | 1736.84 |  |  |  |  |  |  |  |  |
| 3  | 743.7762 | 2010.09 |  |  |  |  |  |  |  |  |
| 4  | 691.7653 | 2283.33 |  |  |  |  |  |  |  |  |
| 5  | 639.2068 | 2557.48 |  |  |  |  |  |  |  |  |
| 6  | 580.1905 | 3053.88 |  |  |  |  |  |  |  |  |
| 7  | 180.036  | 3663.10 |  |  |  |  |  |  |  |  |
| 8  | 126.0687 | 3836.98 |  |  |  |  |  |  |  |  |
| 9  | 107.3682 | 3888.64 |  |  |  |  |  |  |  |  |
| 10 | 88.66926 | 3963.41 |  |  |  |  |  |  |  |  |
| 11 | 69.97    | 4055.01 |  |  |  |  |  |  |  |  |
| 12 | 60.6202  | 4108.37 |  |  |  |  |  |  |  |  |
| 13 | 58.75026 | 4122.43 |  |  |  |  |  |  |  |  |
| 14 | 56.27113 | 5471.03 |  |  |  |  |  |  |  |  |

**Table 35: Main results for the Fos-sur-Mer-2019 optimisations**

Results of the optimisations-calculations are also given in the following figures. The Figure 22 shows the “Pareto” front of the total costs and the CO<sub>2</sub> emissions obtained for all runs. The Figure 23 shows the sizing of the electricity production means. Figure 25 and Figure 24 present the detailed costs and CO<sub>2</sub> emissions per component. For each product (electricity, hydrogen and thermal energy), the relative costs (LCOE, LCOH<sub>2</sub> and LCOH) and CO<sub>2</sub> intensities of each product are presented in Figure 26, Figure 27 and Figure 28, respectively. Finally, the yearly electricity production and the yearly hydrogen production are respectively given (Figure 29, Figure 30).

- ⇒ The reference run (*run0*) shows that the electrical and hydrogen productions are respectively ensured by the CCGT and the photovoltaic field and the SMGR with a (LCOE, LCOH<sub>2</sub>) at (35.1 €/MWh<sub>e</sub>, 0.97 €/kg H<sub>2</sub>) for a CO<sub>2</sub> intensity at 9.48 kg CO<sub>2</sub> eq/kg H<sub>2</sub>. The electrical need for the SMGR operation at nominal conditions is about 1.30 MW<sub>e</sub> when the electrical load is 75 MW<sub>e</sub>.
- ⇒ An extra run (called *run-1*) have been considered to evaluate the case where the PV field is removed. The *run-1* is less interesting than the *run0* as LCOH<sub>2</sub> and CO<sub>2</sub> intensity of hydrogen are higher.
- ⇒ After the *run0*, the SMR and the HTSE are used with higher and higher commitments. After the *run6*, the hydrogen production is totally filled by electrolysis; the SMGR is no longer used.
- ⇒ Up to the *run6*, the CO<sub>2</sub> intensity of hydrogen remains greater than 6 kg CO<sub>2</sub> eq/kg H<sub>2</sub>; these values can be compared to two thresholds defining a low-carbon hydrogen production: the CERTIFHy™ limit at 4.4 kg CO<sub>2</sub> eq/kg H<sub>2</sub> and the European taxonomy, hydrogen for which H<sub>2</sub> is considered low-carbon below 3 kg CO<sub>2</sub> eq/kg H<sub>2</sub> (see section

5.2.5).

In the energy system modelled, hydrogen can be considered low carbon from *run7* configuration.

- ⇒ At *run5*, the calculated architecture contains 1 SMR (155 MW<sub>e</sub>, see Figure 29). For this *run5*, CO<sub>2</sub> intensity of hydrogen remains above the CERTIFHy™ threshold as the SMR is not able to fulfil all the electrical production (the CCGT is also used at about 160 MW<sub>e</sub>).
- ⇒ Before the *run7*, the decarbonation of the system is mainly ensured by the use of the HTSE instead of the SMGR for the hydrogen production. The LCOH<sub>2</sub> is strongly increasing (from 0.97 to 2.73 €/kg H<sub>2</sub>) to reach a plateau between *run6* and *run7* when the LCOE is monotonically going up (from 35.1 to 52.8 €/MWh<sub>e</sub>). After the *run7*, the LCOH<sub>2</sub> is increasing again (above 3.07 €/kg H<sub>2</sub>).
- ⇒ At *run7* and after, the architecture contains 2 SMR (310 MW<sub>e</sub>, see Figure 29) running at full power. The CO<sub>2</sub> intensity of hydrogen becomes lower than the CERTIFHy™ and European taxonomy thresholds. The CCGT commitment for the electrical production is strongly decreasing and is partially replaced by the contribution of wind turbines. But the CCGT part is never cancelled because of the intermittency of the renewable electrical energies.

At the *run13*, the CCGT is a little bit more engaged. An extra optimisation (*run14 following the run13 case*) is proposed to analyse the behaviour while imposing CCGT's size to zero. In this case, the wind farm becomes more important (60 wind turbines instead of 18 in *run13*). The (LCOE, LCOH<sub>2</sub>) are higher (74.10 €/MWh<sub>e</sub>, 3.85 €/kg H<sub>2</sub>) also than in the *run13* (66.74 €/MWh<sub>e</sub>, 3.58€/kg H<sub>2</sub>) at a lower CO<sub>2</sub> intensity of hydrogen (0.50 instead of 0.67 kg CO<sub>2</sub> eq/kg H<sub>2</sub>). This (*run14*) is less interesting as the wind turbines CAPEX becomes preponderant compared to the other components.

- ⇒ A LTE is used to produce more hydrogen during the peaks of renewable energies. PERSEE provides the first solution that meets all the constraints included the CO<sub>2</sub> emission constraint and that minimizes the total costs with a gap of 5%. There are equivalent solutions that fulfil all these requirements because it is balance between total costs and CO<sub>2</sub> emissions.
- ⇒ The hydrogen storage is requested up to *run7* to store excess electricity production from wind turbines. When the hydrogen storage is full, electrical energy is released toward the grid.
- ⇒ For all runs, the thermal energy cost is relatively constant (19.55 €/MWh<sub>th</sub>); the CO<sub>2</sub> intensity of the thermal energy is given by the E-SMR (1 kg/MWh<sub>th</sub>).
- ⇒ More detailed analysis is given in the next section.

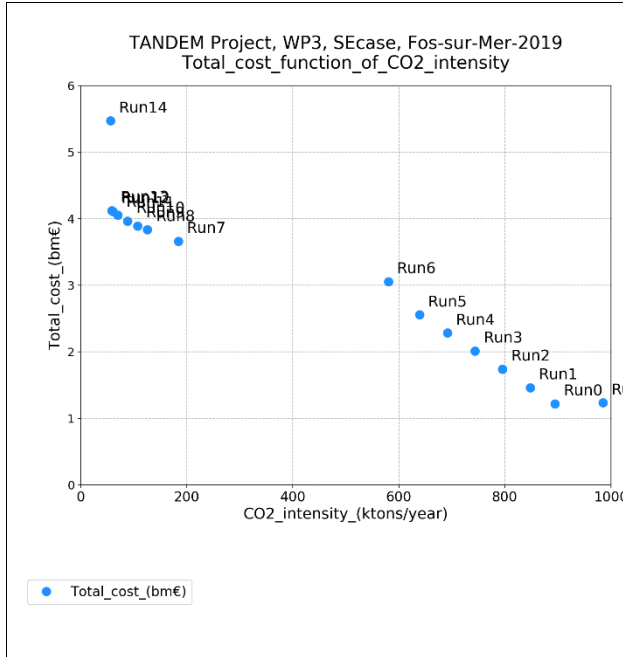


Figure 22: Fos-sur-Mer-2019, Total Costs-CO2 emissions « Pareto » front

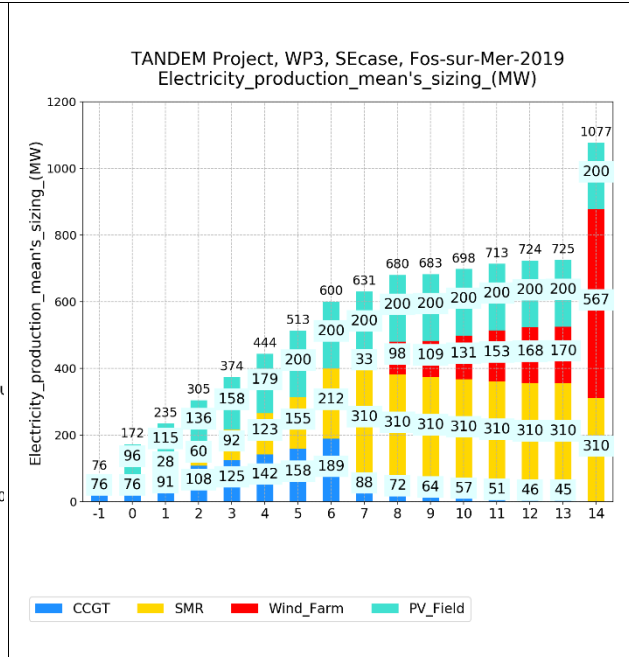


Figure 23: Fos-sur-Mer-2019, Sizing of the electrical production means (MW)

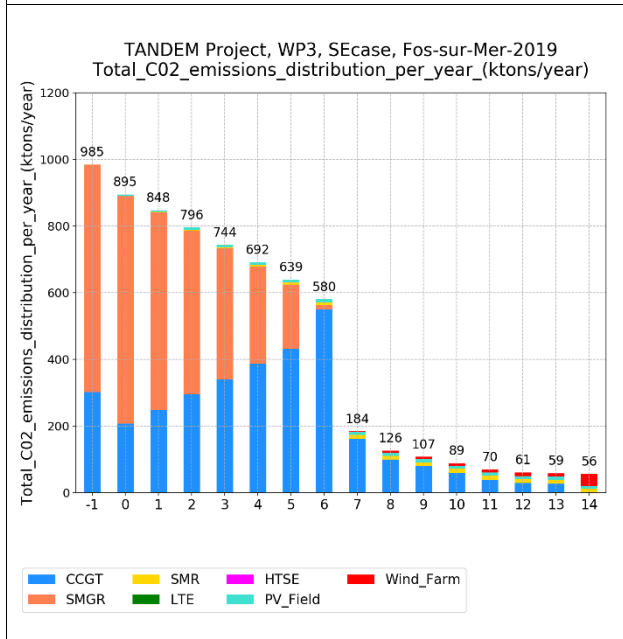


Figure 24: Fos-sur-Mer-2019, total CO2 emissions (ktons/year)

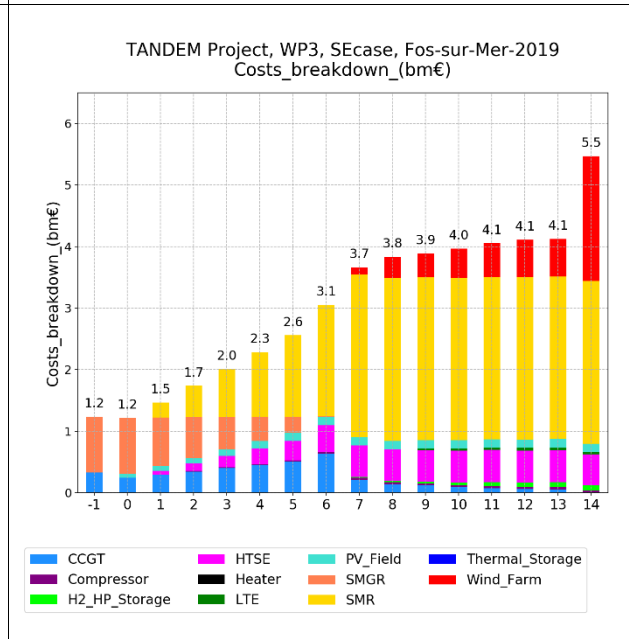


Figure 25: Fos-sur-Mer-2019, total Costs (bm€)

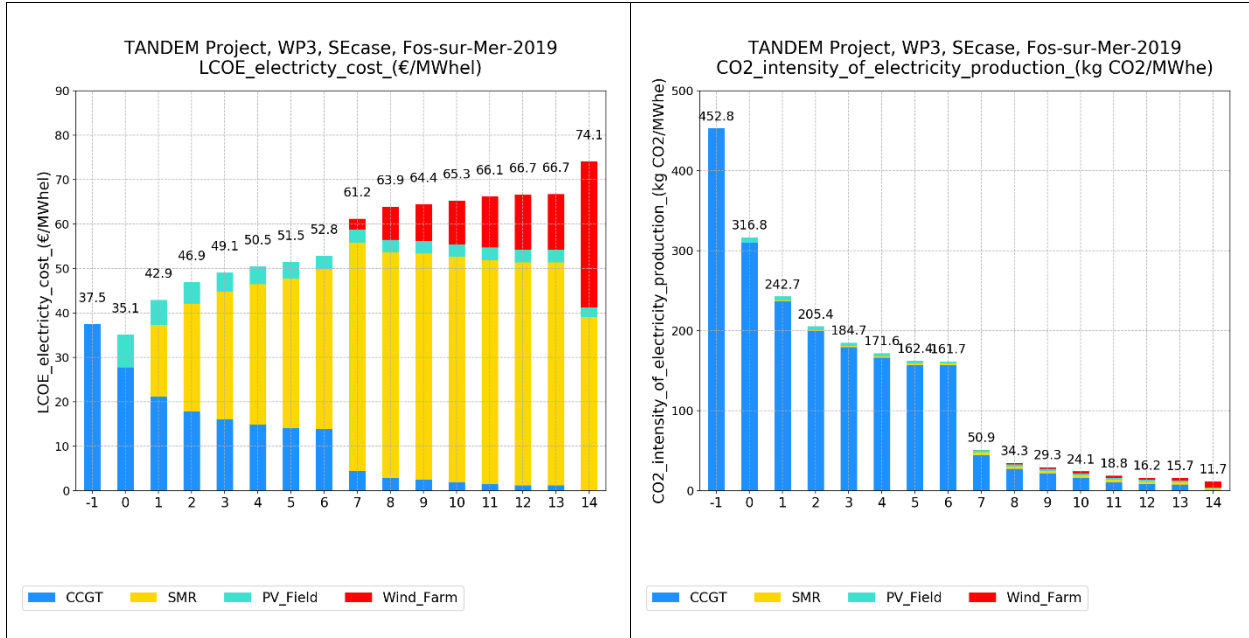


Figure 26: Fos-sur-Mer-2019, electricity cost (LCOE) and CO<sub>2</sub> intensity of electricity

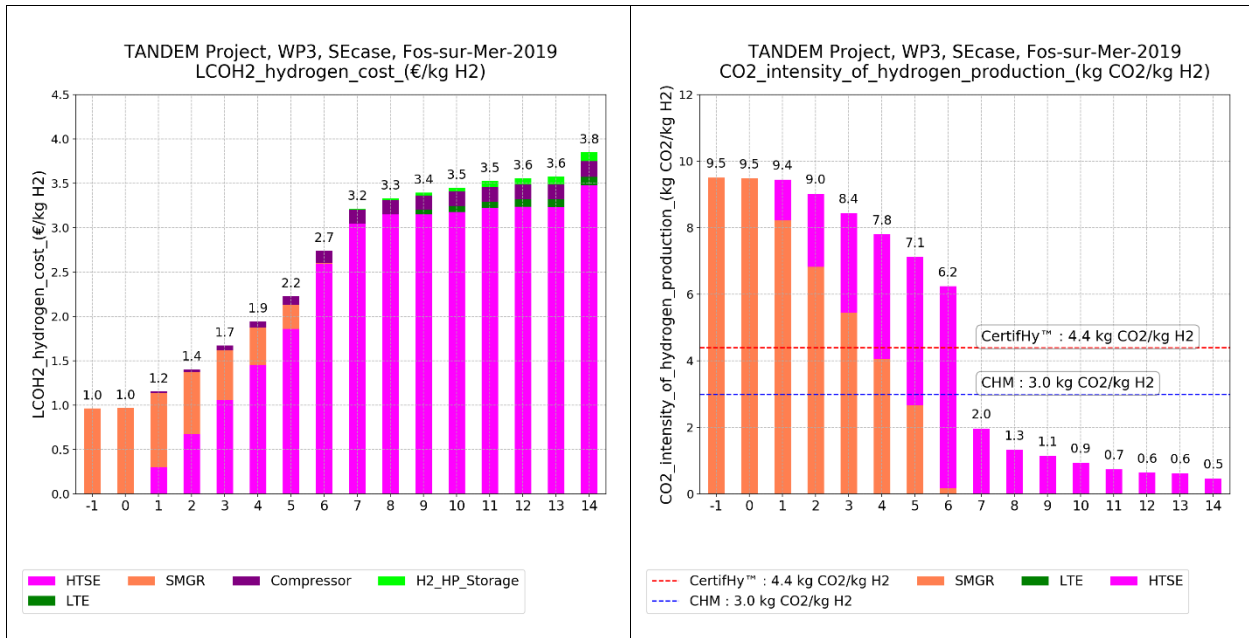


Figure 27: Fos-sur-Mer-2019, hydrogen cost (LCOH<sub>2</sub>) and CO<sub>2</sub> intensity of hydrogen

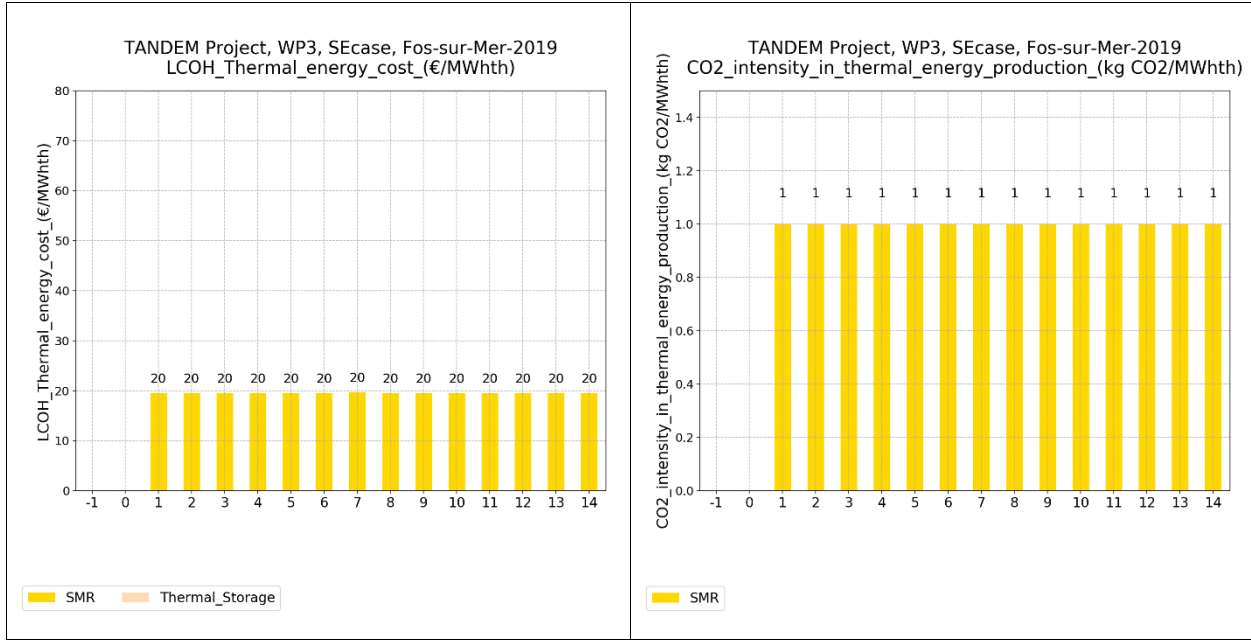


Figure 28: Fos-sur-Mer-2019, thermal energy cost (LCOH) and CO<sub>2</sub> intensity of heat

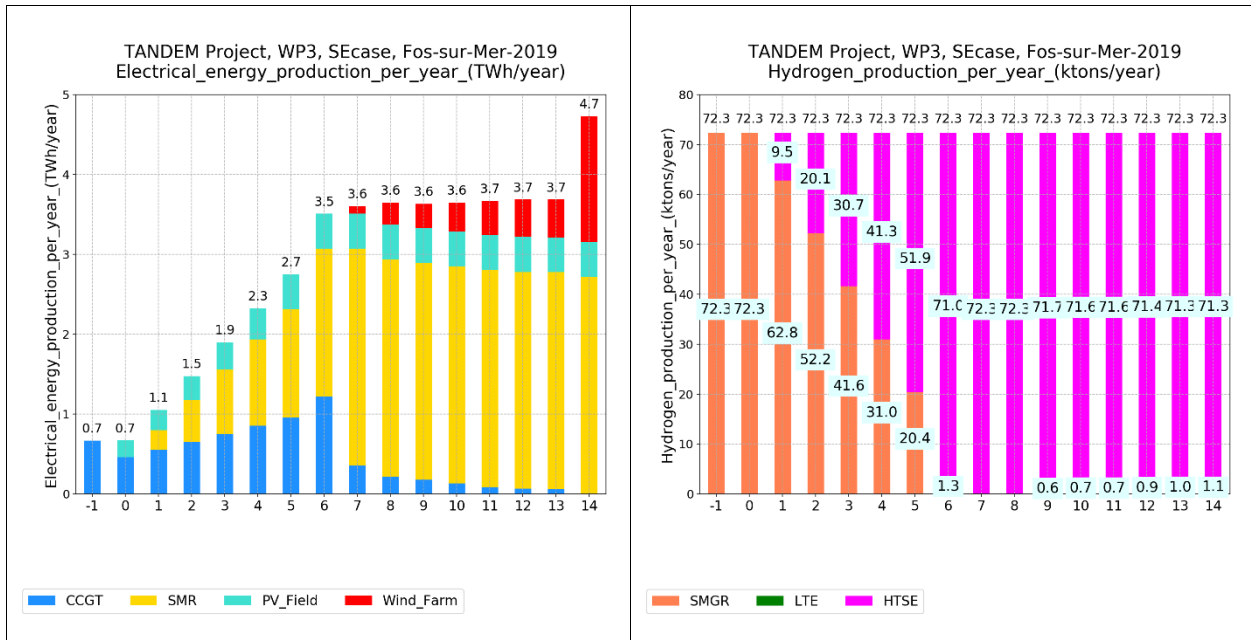


Figure 29: Fos-sur-Mer-2019, electricity production (TWh/year)

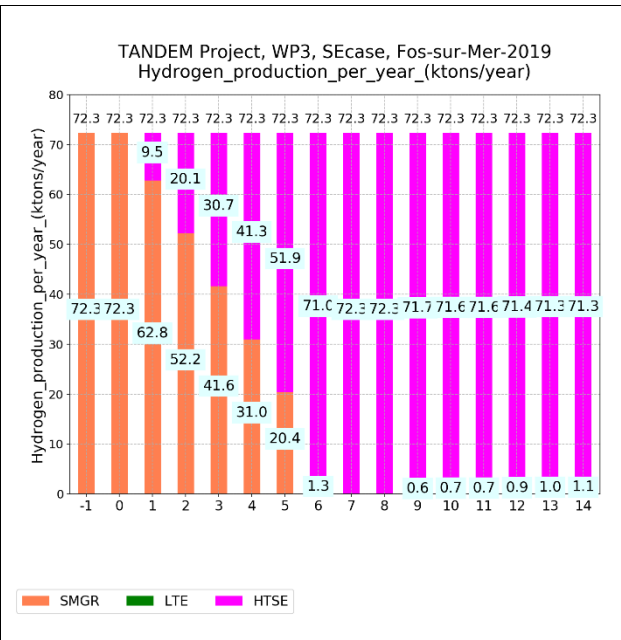


Figure 30: Fos-sur-Mer-2019, hydrogen production (ktons/year)

The present study shows the interest to a deeper analysis of four cases as expected in the frame of the TANDEM project:

- The current scenario (now to 2035) at “Low SMR deployment”, the run0 simulation without **no SMR**.

- The “High SMR deployment for 2035” scenario (run5) where only **one unit of E-SMR** is deployed.
- The “2050 High SMR deployment” scenario (run 7) which is the first architecture with **two units of E-SMR** and low-carbon hydrogen produced only with HTSE.
- The “2050 High SMR deployment +” is obtained with a **two units of E-SMR** architecture (run13) and is the most decarbonized studied scenario.

### 5.5 Detailed analysis of the four worthwhile configurations

Table 36 and Figure 31 summarize the main parameters and component sizing of the chosen architectures (runs 0, 5, 7 and 13):

- The “run5-2035-1 SMR” configuration leads to a +200% more expensive for a -28% less CO<sub>2</sub> emissive solution compared to the “run0-2035-no SMR” case. Its global CO<sub>2</sub> intensity of hydrogen remains higher than the CERTIFHy™ threshold.
- The “run7-2050-2 SMR” configuration leads to a +43% more expensive for a -71% less CO<sub>2</sub> emissive solution compared to the “run5-2035-1 SMR” case. Its global CO<sub>2</sub> intensity of hydrogen becomes lower than the CERTIFHy™ threshold.
- The “run13-2050-2 SMR” configuration leads to a +61% more expensive for an about 10 times less CO<sub>2</sub> emissive solution compared to the “run5-2035-1 SMR” case. Its global CO<sub>2</sub> intensity of hydrogen becomes lower than the CERTIFHy™ threshold.

| Component                 | Variable                                    | run 0<br>2035-Low<br>SMR | run 5<br>2035-high<br>SMR | run 7<br>2050-High<br>SMR | run 13<br>2050-High<br>SMR+ |
|---------------------------|---|--------------------------|---------------------------|---------------------------|-----------------------------|
| LCOH <sub>2</sub>         | €/kg H <sub>2</sub>                         | 0.96                     | 2.22                      | 3.21                      | 3.58                        |
| LCOE                      | €/MWh <sub>e</sub>                          | 35.12                    | 51.46                     | 61.20                     | 66.74                       |
| LCOH                      | €/MWh <sub>th</sub>                         |                          |                           | 19.55                     |                             |
| CO <sub>2</sub> intensity | kg CO <sub>2</sub> eq/kg H <sub>2</sub>     | 9.48                     | 7.12                      | 1.96                      | 0.67                        |
|                           | kg CO <sub>2</sub> eq /MWh <sub>e</sub>     | 316                      | 162                       | 50.88                     | 15.7                        |
|                           | kg CO <sub>2</sub> eq /MWh <sub>th</sub>    |                          |                           | 1                         |                             |
| Total costs               | bm€   | 1.217                    | 2.558                     | 3.663                     | 4.122                       |
| CCGT                      | Min-Max electrical power (MW <sub>e</sub> ) | 0-76                     | 0-158                     | 0-88                      | 0-46                        |
| H <sub>2</sub> Compressor | Min-Max electrical power (MW <sub>e</sub> ) |                          | 0-12                      | 0-19                      | 0-20                        |
| H <sub>2</sub> Storage    | Max storage capacity (kg)                   |                          |                           | 16000                     | 126000                      |
| HTSE                      | Min-Max Electrical power (MW <sub>e</sub> ) |                          | 226                       | 367                       | 372                         |
|                           | Mean hydrogen production (kg/h)             |                          | 5990                      | 8259                      | 8170                        |
|                           | Mean thermal power (MW <sub>th</sub> )      |                          | 47.4                      | 66.1                      | 65.1                        |
| LTE                       | Max electrical power (MW <sub>e</sub> )     |                          |                           |                           | 45                          |
|                           | Mean hydrogen production (kg/h)             |                          |                           |                           | 622                         |
| PV Field                  | Peak power (MW <sub>e</sub> )               |                          |                           | 200                       |                             |
| Wind Farm                 | Number of units (9.5 MW <sub>e</sub> )      |                          |                           | 4                         | 18                          |
|                           | Max power (MW <sub>e</sub> )                |                          |                           | 33                        | 167                         |
| SMGR                      | Mean hydrogen production (kg/h)             | 8257                     | 2267                      |                           |                             |

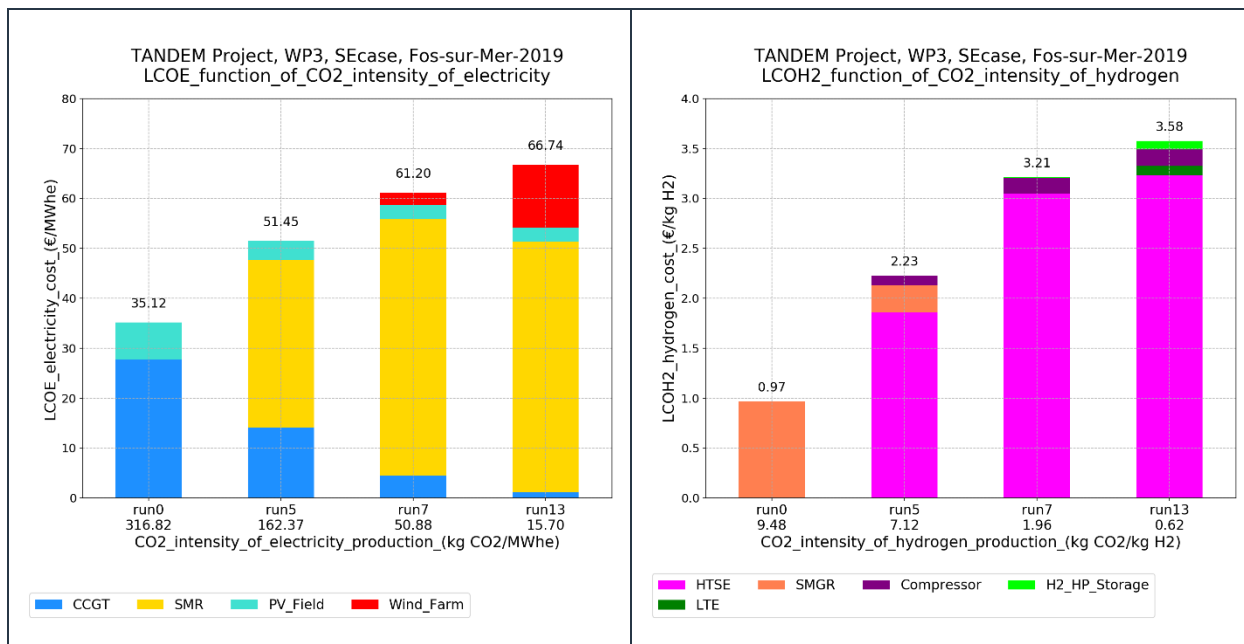


|                    |   |     |         |         |
|--------------------|---|-----|---------|---------|
|                    | Auxiliary electrical power (MW <sub>e</sub> ) | 1.3 | 0.3     |         |
| SMR<br>(base-load) | Number of units                               |     | 1 SMR   | 2 SMR   |
|                    | Min-Max electrical power (MW <sub>e</sub> )   |     | 155-155 | 310-310 |
|                    | Min-Max thermal power (MW <sub>th</sub> )     |     | 50-50   | 100-100 |

**Table 36: Fos-sur-Mer-2019, Main results for the four selected cases**

The costs are expressed in €<sub>2023</sub> thus the four cases can be compared and they can also be compared to current costs and in particular to current LCOH<sub>2</sub>. It is worth reminding again that the calculations use time series of year 2019 where the natural gas price was low and off course results would be different if year 2022 is used. The CCGT is still there in run 13 also because of the intermittency of the renewable energies: as the E-SMR size is limited to two units and PV to 200 MW, the offshore wind farm must be oversized to completely remove the CCGT.

Finally, no CO<sub>2</sub> allowance have been considered in the study but it is worth mentioning that a carbon tax of 100 €/ton CO<sub>2</sub> would lead to the same LCOE for run 0 and run 7 and a carbon tax of 172 €/ton CO<sub>2</sub> would lead to the same total costs for run 0 and run 7 thus to very similar LCOE, LCOH, LCOH<sub>2</sub> (as the outputs are nearly identical). It is also worth mentioning that the cost of CO<sub>2</sub> reached more than 100 €/ton CO<sub>2</sub> in February 2023.

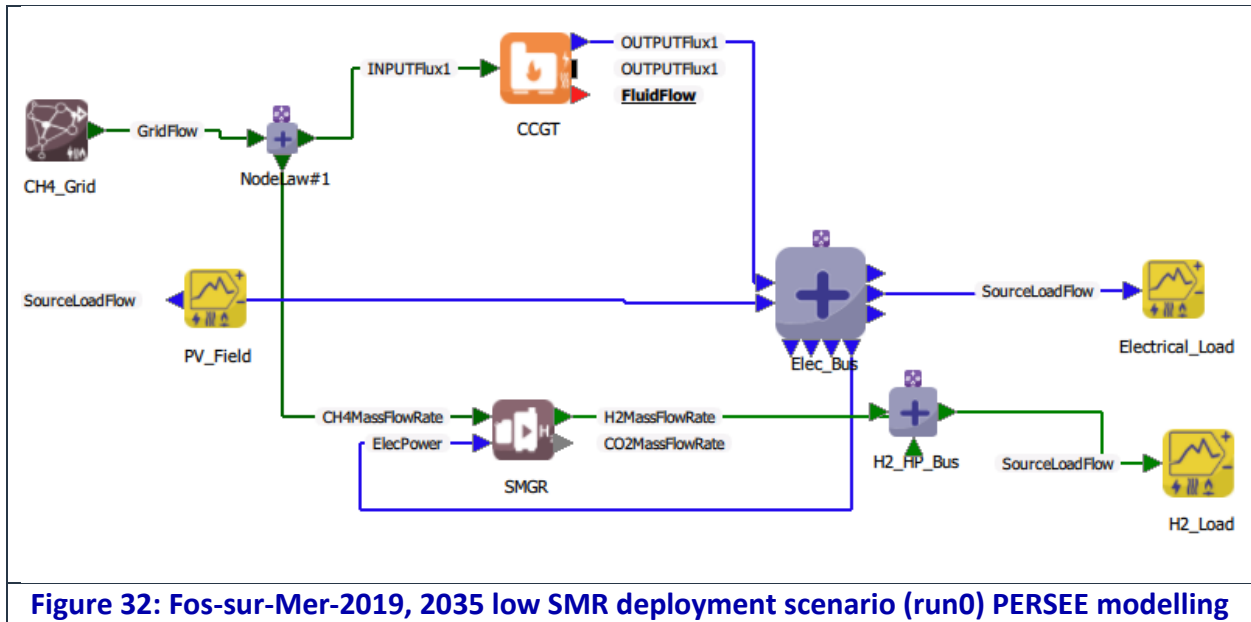


**Figure 31: Fos-sur-Mer-2019, Main results for the three selected cases (0, 5 and 13)**

### 5.5.1 2035 low SMR deployment scenario (run0)

The “2035 Low SMR deployment” scenario (run0) corresponds to a “business as usual” case so to an architecture without any SMR. Figure 32 shows the architecture of this configuration.

As a reminder, this configuration “business as usual” leads to a **LCOE=35.1 €/MWh<sub>e</sub>**, **LCOH<sub>2</sub>= 0.96 €/kg H<sub>2</sub>** with **CO<sub>2</sub> intensities respectively at 316 kg CO<sub>2</sub> eq/MWh<sub>e</sub> and 9.48 kg CO<sub>2</sub> eq/kg H<sub>2</sub>**.



The hydrogen load is fully ensured by the SMGR. The electrical loads are fulfilled by the CCGT and a 200 MW<sub>e</sub> PV field. The flexibility of the system due to the photovoltaic field intermittent production is handled by the CCGT as it is not profitable to build a hydrogen storage from an economic point of view. Figure 33 presents the dynamic evolution of electricity production on the left and of electricity consumption on the right, over a time window of two weeks.

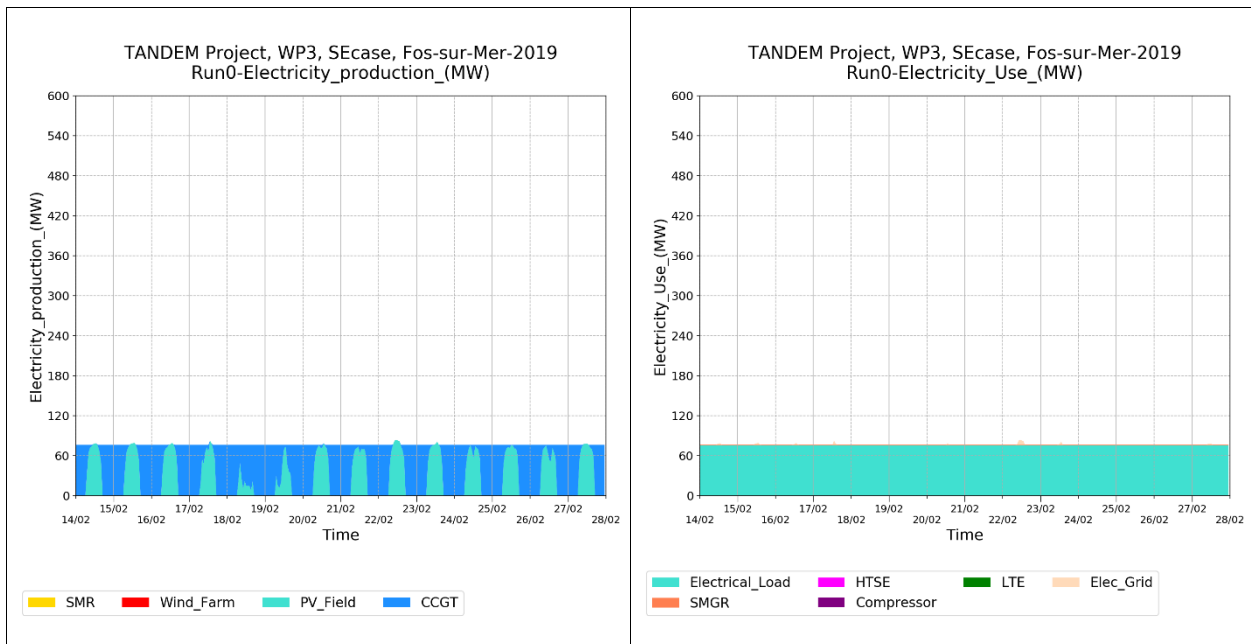
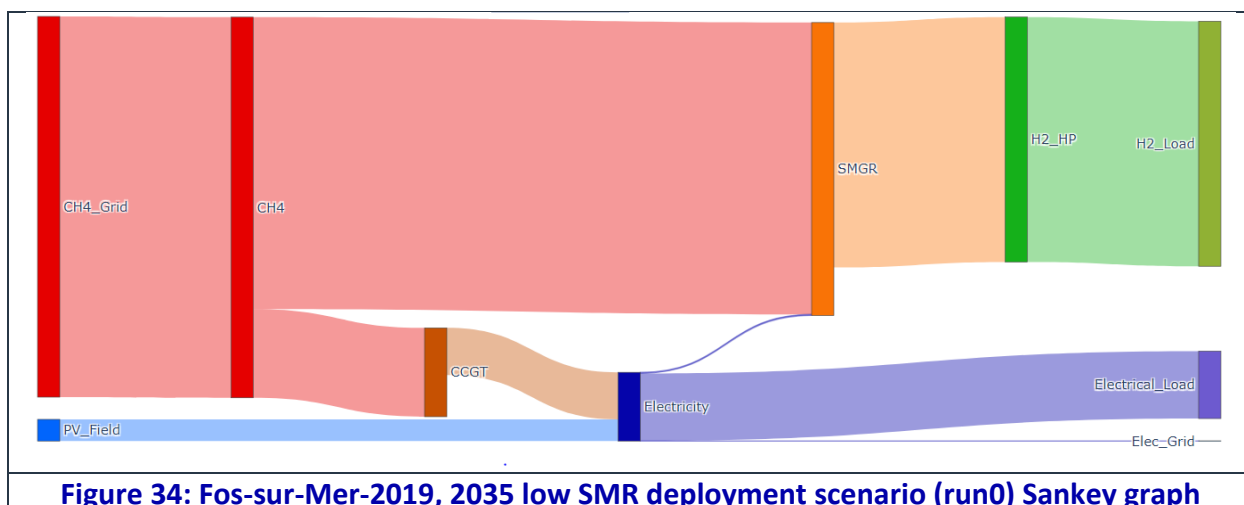


Figure 34 shows the energy fluxes owing to a Sankey graph.



**Figure 34: Fos-sur-Mer-2019, 2035 low SMR deployment scenario (run0) Sankey graph**

Table 35 gathers the main results of the reference case (run0) for this scenario and two variants:

- The run-1 where the PV field is removed.
- The run0b, “electricity supplied by the French grid (run0b)”, an additional post-calculation where the CCGT is replaced by a grid with a carbon intensity of 55 kg CO<sub>2</sub> eq/MWh<sub>e</sub> and the electricity price is given in section 5.2.3.1 and Figure 18 (SPOT price).

The comparison of run0 with the (run-1) shows the interest of PV renewable energy as for the run-1, the CO<sub>2</sub> emissions are about 10% higher.

The CO<sub>2</sub> emission balance for run0 and run-1 can be also compared with the assumption “electricity supplied by the French grid (run0b)” where the global and average emission factor is close to 55 kg CO<sub>2</sub> eq/MWh. The case run0b is estimated by assuming that the grid supplies the same electrical energy taking into account the CCGT efficiency. The following table summarizes the runs (0,0b and -1). Hydrogen production are at the same CO<sub>2</sub> intensity when cost and CO<sub>2</sub> intensities of the electrical production are strongly lower for the run0b case compared with the run0 base case.

| Run |                               | Total CO <sub>2</sub> emissions (ktons/year) | LCOH (€/kg H <sub>2</sub> ) | LCOE (€/MWh <sub>e</sub> ) | CI_H <sub>2</sub> (kg CO <sub>2</sub> eq/kg H <sub>2</sub> ) | CI_E (kg CO <sub>2</sub> eq/MWh <sub>e</sub> ) |
|-----|-------------------------------|--|-----------------------------|----------------------------|--|--|
| -1  | without PV                    | 984.8  | 0.96                        | 37.48                      | 9.5  | 452.8  |
| 0   | base case                     | 894.7  | 0.96                        | 35.11                      | 9.48   | 316  |
| 0b  | Electricity grid without CCGT | -  | 0.96                        | 9.47                       | 9.44   | 44.2   |

**Table 37: Fos-sur-Mer-2019, Main results for 2035-low SMR (run0) case**

The scenario “business as usual” could be completed by a sensitivity study to take into account CCS or another way to replace the CCGT.

### 5.5.2 2035 high SMR deployment scenario (run5)

In the “2035 High SMR deployment” scenario (run5), only one unit of the E-SMR is deployed. For this second case (run5), the electrical load is ensured with one unit of the E-SMR (155 MW<sub>e</sub>), a CCGT (158 MW<sub>e</sub>) and a photovoltaic field (200 MW<sub>e</sub>). Hydrogen is produced through the SMGR and the HTSE with the associated compressor to increase the pressure from 1 to 30 bars.

For this case, the SMR and the HTSE are running at full power and 100% load factor. The calculated architecture is shown in Figure 35.

As a reminder, this configuration “High SMR deployment for 2035” leads to LCOE=51.45 €/MWh<sub>e</sub> and LCOH<sub>2</sub>=2.22 €/kg H<sub>2</sub> with the CO<sub>2</sub> intensities respectively at 162 kg CO<sub>2</sub> eq/MWh<sub>e</sub> and 7.12 kg CO<sub>2</sub> eq/kg H<sub>2</sub>.

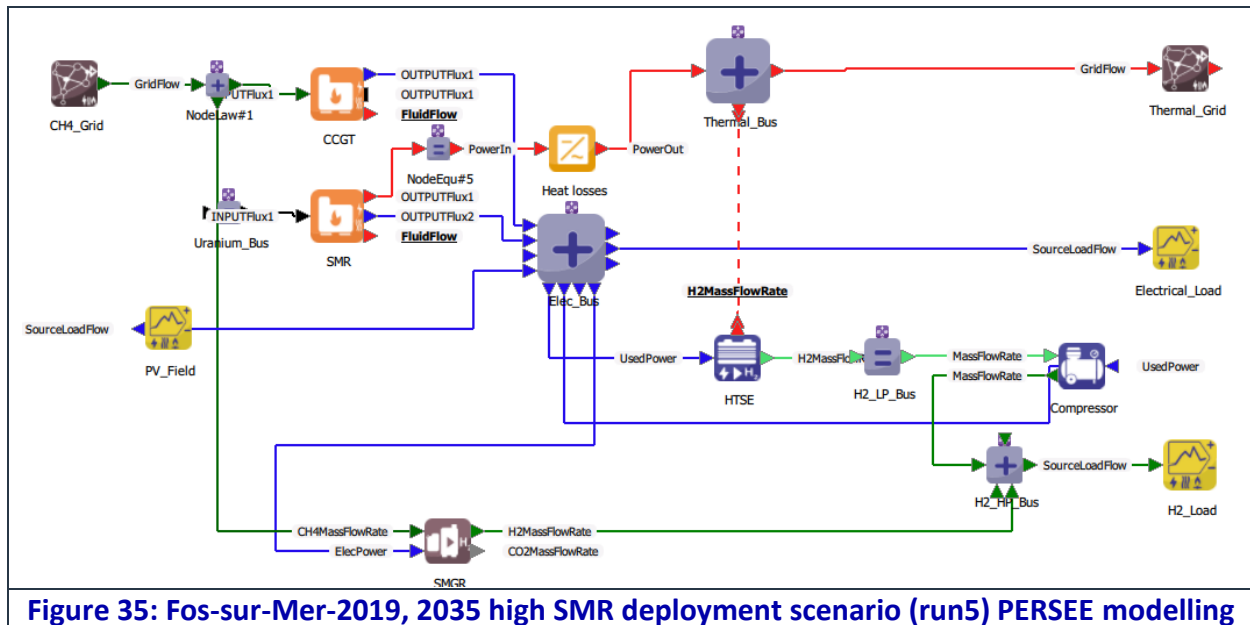
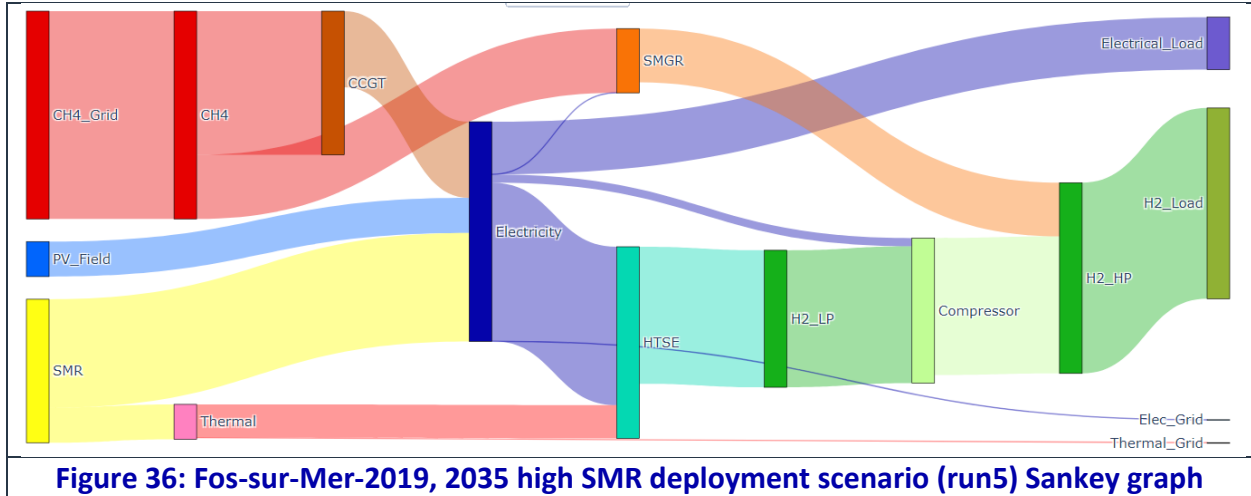


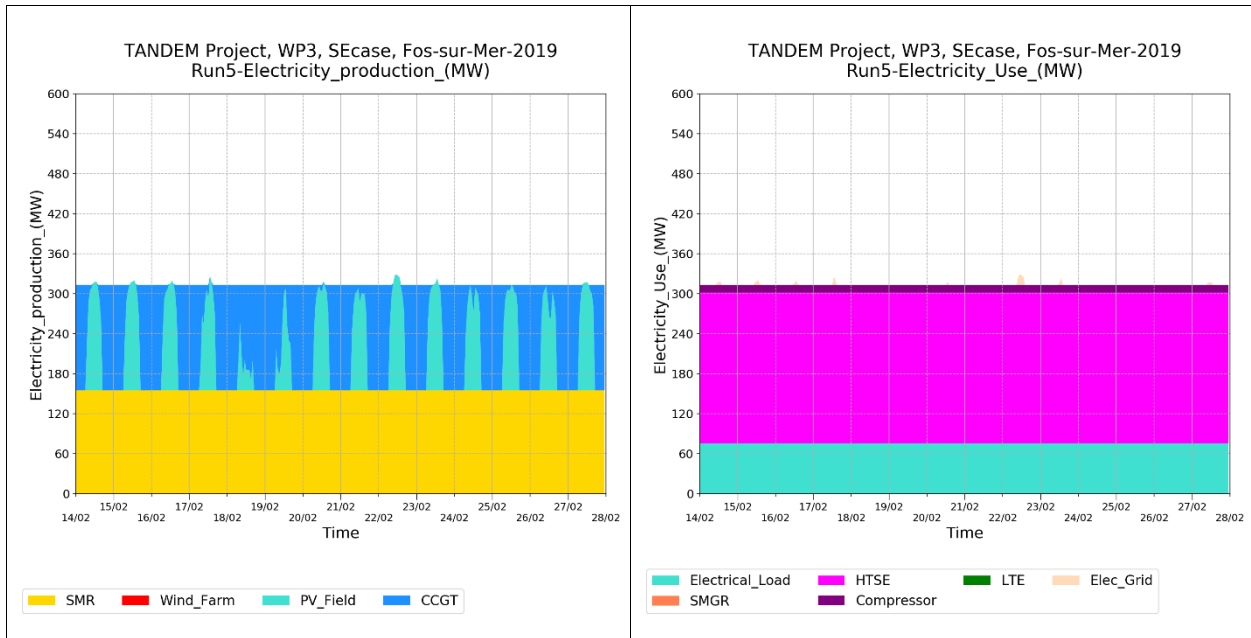
Figure 35: Fos-sur-Mer-2019, 2035 high SMR deployment scenario (run5) PERSEE modelling

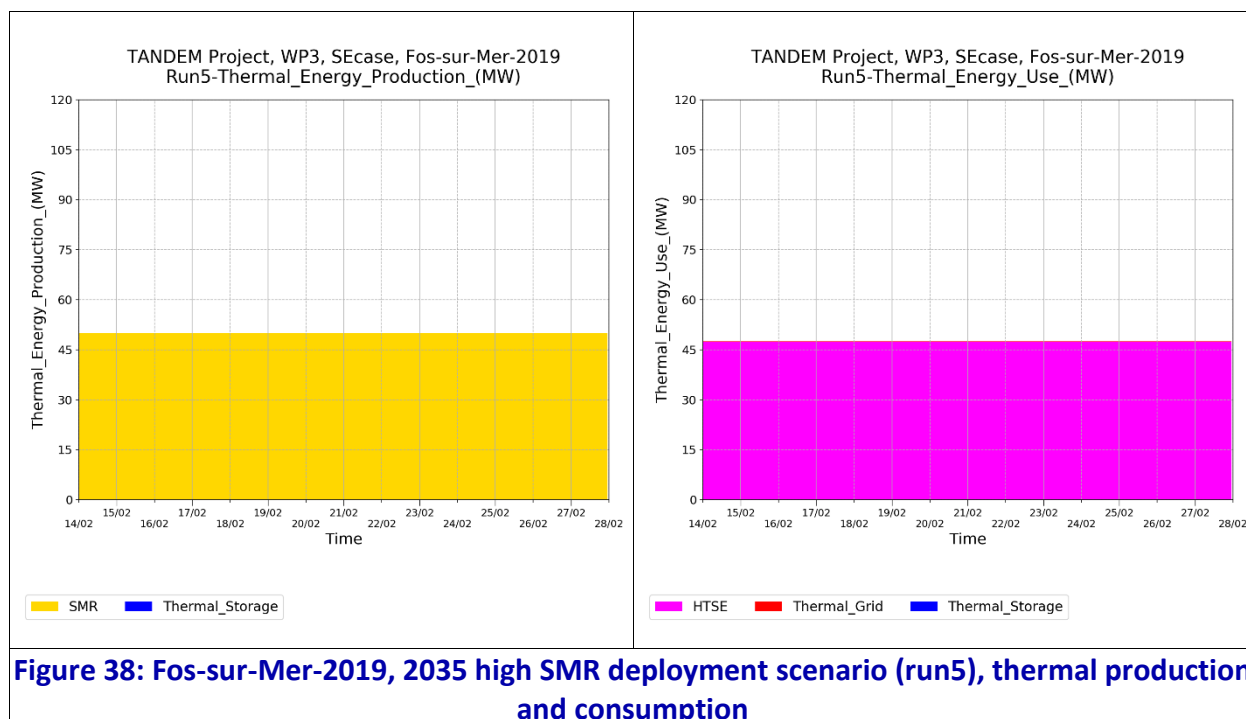
Figure 36 shows the yearly energy fluxes through a Sankey graph.



No thermal and hydrogen storages are calculated. Thermal needs for the HTSE are 47 MW<sub>th</sub> when the SMR production is 50 MW<sub>th</sub>. The CCGT and the SMGR ensure the flexibility for electrical and hydrogen productions.

Figure 37 and Figure 38 show the system operating results for a time window of two weeks and the electrical and thermal productions (SMR, PV field and CCGT) and consumptions (electrical load, HTSE, SMGR and compressor). No thermal energy is extracted from the system; the electrical flexibility needed by the system is ensured by the CCGT.





**Figure 38: Fos-sur-Mer-2019, 2035 high SMR deployment scenario (run5), thermal production and consumption**

The CO<sub>2</sub> emission balance for run5 can be also compared with the assumption “electricity supplied by the French grid (run5b)” where the global and average emission factor is close to 55 kg CO<sub>2</sub> eq/MWh. Table 38 gathers the main results of the “2035 High SMR deployment” case (run5) for this scenario and the variant (run5b). As for the previous case run0, the electricity and hydrogen costs and the CO<sub>2</sub> intensities are strongly reduced thanks to the electrical grids (run5b).

| Fluxes                                   | Component                                | run5 with CCGT                |     | run5b without CCGT |     |
|--|--|-------------------------------|-----|--------------------|-----|
|  |  | Power, Energy or mass         |     |                    |     |
| Electrical                               | SMR                                      | 155 MW-1358 GWh               | 49% | 155 MW-1358 GWh    | 49% |
|  | PV                                       | 438 GWh                       | 16% | 438 GWh            | 16% |
|  | CCGT                                     | 953 GWh                       | 35% | 0 GWh              | 0%  |
|  | Electrical grid                          |                               |     | 953 GWh            | 35% |
| Hydrogen load                            | SMGR                                     | 19.8 ktons H <sub>2</sub> 27% |     |                    |     |
|  | HTSE                                     | 52.5 ktons H <sub>2</sub> 73% |     |                    |     |
| Thermal need                             | SMR production                           | 50 MW-442 GWh                 |     |                    |     |
|  | HTSE need                                | 47MW-420 GWh                  |     |                    |     |
| LCOE                                     | €/MWh <sub>e</sub>                       | 51.45                         |     | 38.4               |     |
| LCOH <sub>2</sub>                        | €/kg H <sub>2</sub>                      | 2.22                          |     | 1.85               |     |
| CO <sub>2</sub> intensity of hydrogen    | kg CO <sub>2</sub> eq /kg H <sub>2</sub> | 7.12                          |     | 3.33               |     |
| CO <sub>2</sub> intensity of electricity | kg CO <sub>2</sub> eq /MWh <sub>e</sub>  | 162                           |     | 24.4               |     |

**Table 38: Fos-sur-Mer-2019, Main results for 2035-high SMR (run5) case**

### 5.5.3 2050 scenario (run13)

The “2050 scenario” is obtained with a two units E-SMR architecture (run13).

As a reminder, this configuration “2050 scenario” leads to the LCOE of 66.74 €/MWh<sub>e</sub> and the LCOH<sub>2</sub> of 3.58 €/kg H<sub>2</sub> with CO<sub>2</sub> intensities at 17 kg CO<sub>2</sub> eq/MWh<sub>e</sub> for electricity and 0.67 kg CO<sub>2</sub> eq/kg H<sub>2</sub> for hydrogen. The carbon intensity of hydrogen is lower than the CERTHIFY threshold (4.4 kg CO<sub>2</sub> eq/kg H<sub>2</sub>).

The Figure 39 and Figure 40 show respectively the calculated PERSEE architecture and the produced and consumed energy SANKEY distributions.

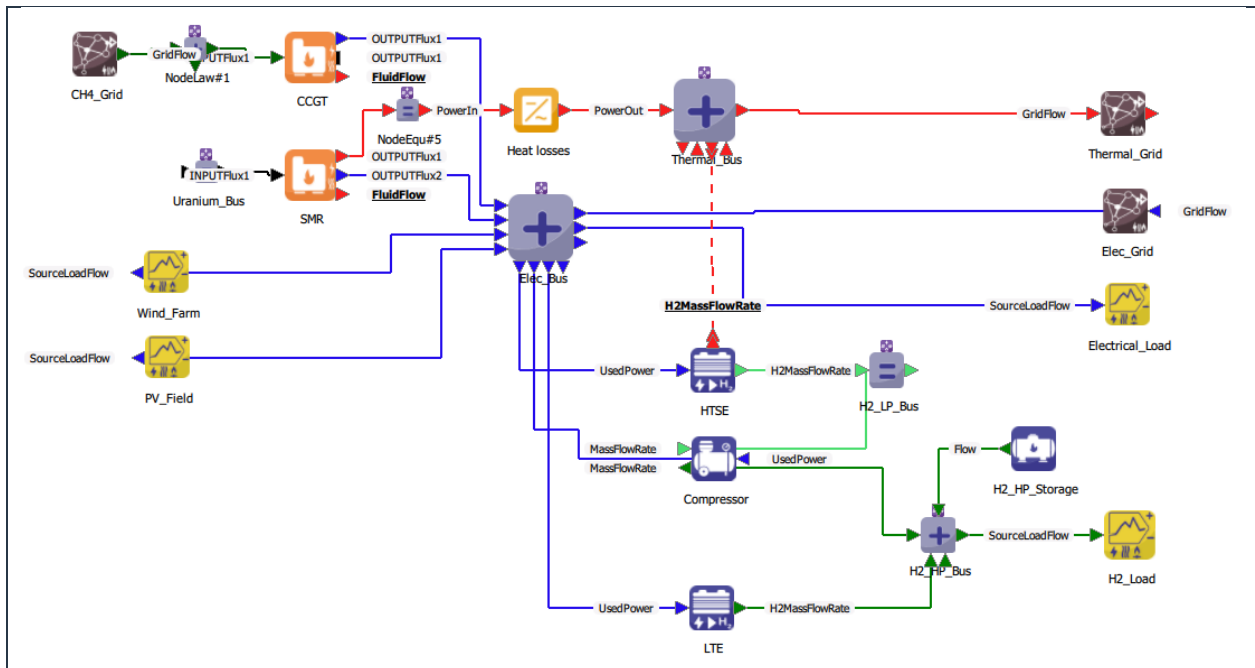


Figure 39: Fos-sur-Mer-2019, 2050 high SMR deployment scenario (run13) PERSEE modelling

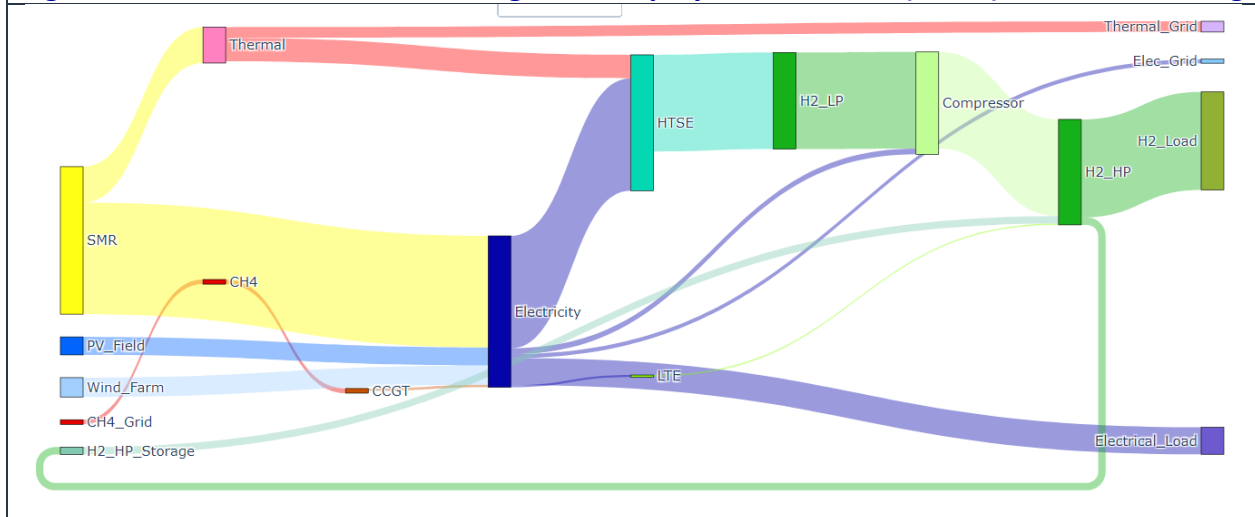


Figure 40: Fos-sur-Mer-2019, 2050 high SMR deployment scenario (run13) Sankey graph

Figure 41 presents, on the left, the contributions from electricity producers over a time window of two weeks and on the right, the consumptions from the electricity consumers over the same window. The electrical needs (load + HTSE + compressor) are mainly fulfilled by the two units of

the E-SMR (310 MW<sub>e</sub>) and the renewable energy sources (PV and wind turbines). The two units of the E-SMR are running at full power all the time. It can be noticed that the two units of the E-SMR are not enough to supply the HTSE (372 MW<sub>e</sub>). PERSEE finds out that the optimal configuration still contains residual CCGT that is used occasionally as it is cheaper than increasing the wind farm capacity. PERSEE also consider a LTE that is mainly used during excess of electrical energy. A small amount of excess electricity is delivered to the electrical network.

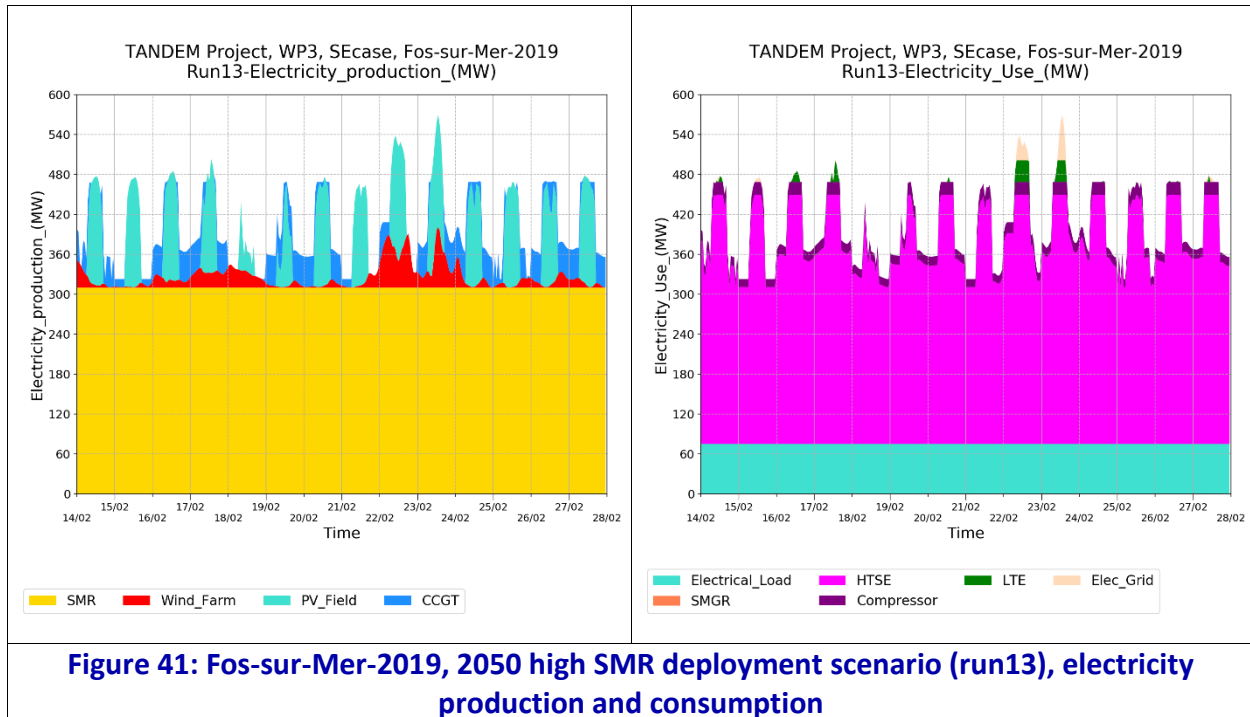
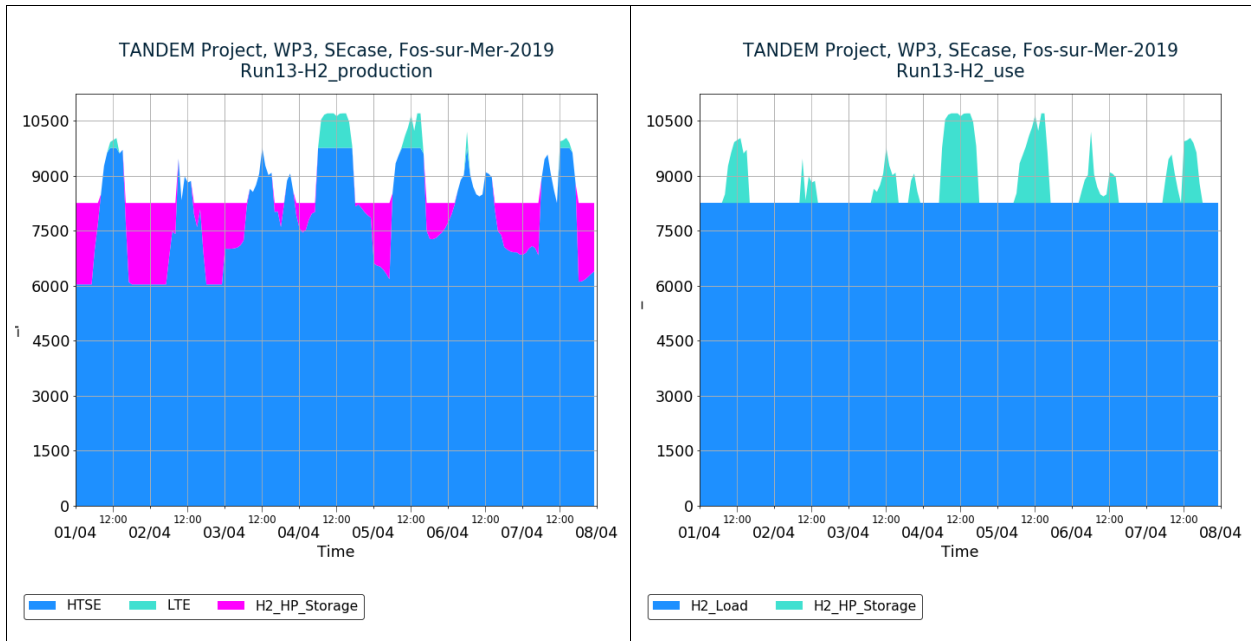
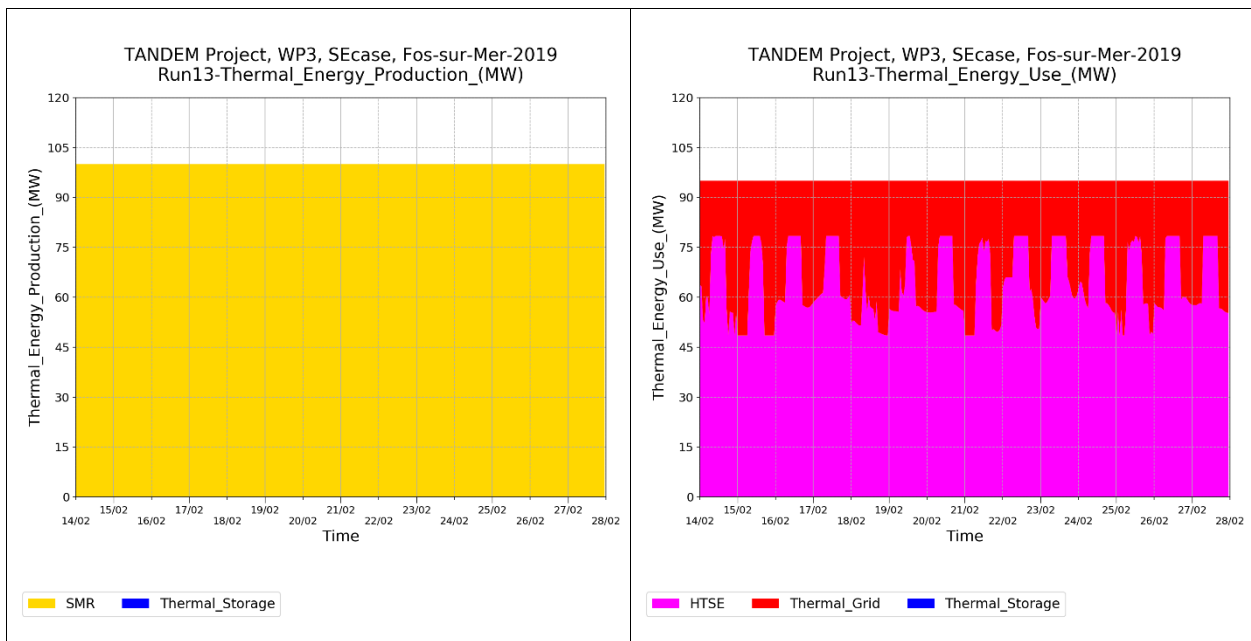


Figure 42 shows the hydrogen production over a time window of one week on the left and the corresponding consumption on the right. The hydrogen service is mainly ensured by the HTSE and the hydrogen storage ensures the flexibility of the system needed due to intermittent electricity production (PV and wind).



**Figure 42: Fos-sur-Mer-2019, 2050 high SMR deployment scenario (run13), hydrogen production and consumption**

Figure 43 presents the heat production over a time window of one week on the left and the heat consumption on the same period on the right. The E-SMR produce a constant amount of heat (100 MW<sub>th</sub>) but the consumption from the HTSE is lower and variable. Excess of heat is released to a heat network for free.



**Figure 43: Fos-sur-Mer-2019, 2050 high SMR deployment scenario (run13), thermal production and consumption**

Two additional runs are conducted in order to better understand the system operation:



- The run131 ("without-LTE") where the LTE size is set to 0 to force the hydrogen production only by the HTSE at the same global carbon intensity.
- The run14 "without-fossil-fuel" where the CCGT contribution is set to 0; the purpose is to analyse the technical, economic and environmental impacts of a totally decarbonised system.

Comparisons between cases 13, 131 and 14 are given in Table 39. Additional figures to present the results can be found in Annex 9.2.

| 2050 scenario                            |   |                     |                           |                                |
|--|---|---------------------|---------------------------|--------------------------------|
| Component                                | Variable                                | run 13<br>base case | run131<br>("without-LTE") | run14<br>"without-fossil-fuel" |
| LCOH <sub>2</sub>                        | €/kg H <sub>2</sub>                     | 3.57                | 3.57                      | 3.84                           |
| LCOE                                     | €/MWh <sub>e</sub>                      | 66.73               | 66.89                     | 74.10                          |
| CO <sub>2</sub> intensity of hydrogen    | kg CO <sub>2</sub> eq/kg H <sub>2</sub> | 0.67                | 0.66                      | 0.50                           |
| CO <sub>2</sub> intensity of electricity | kg CO <sub>2</sub> eq/MWh <sub>e</sub>  | 17                  | 16.92                     | 12.73                          |
| Total costs                              | bm€                                     | 4.122               | 4.139                     | 5.471                          |

| 2050 scenario Sizing   |   |                     |                           |                                |
|------------------------|---|---------------------|---------------------------|--------------------------------|
| Component              | Variable                                    | run 13<br>base case | run131<br>("without-LTE") | run14<br>"without-fossil-fuel" |
| SMR<br>(Base-load)     | Number of units                             | 2                   |                           |                                |
|                        | Min-Max electrical power (MW <sub>e</sub> ) | 310-310             |                           |                                |
|                        | Min-Max thermal power (MW <sub>th</sub> )   | 100-100             |                           |                                |
| PV Field               | Peak power (MW <sub>e</sub> )               | 200                 |                           |                                |
| Wind Farm              | Number of units (9.5 MW <sub>e</sub> )      | 18                  | 19                        | 60                             |
|                        | Max power (MW <sub>e</sub> )                | 167                 | 177                       | 570                            |
| CCGT                   | Min-Max electrical power (MW <sub>e</sub> ) | 0-46                | 0-42                      | 0-0                            |
| Compressor             | Min-Max electrical power (MW <sub>e</sub> ) | 0-20                | 0-20                      | 0-18                           |
| HTSE                   | Min-Max Electrical power (MW <sub>e</sub> ) | 0-372               | 0-382                     | 0-354                          |
|                        | Mean thermal power (MW <sub>th</sub> )      | 65.3                | 58                        | 57                             |
| LTE                    | Min-Max electrical power (MW <sub>e</sub> ) | 0-45                | 0                         | 0-31                           |
| H <sub>2</sub> Storage | Max storage capacity (kg)                   | 126000              | 160000                    |                                |

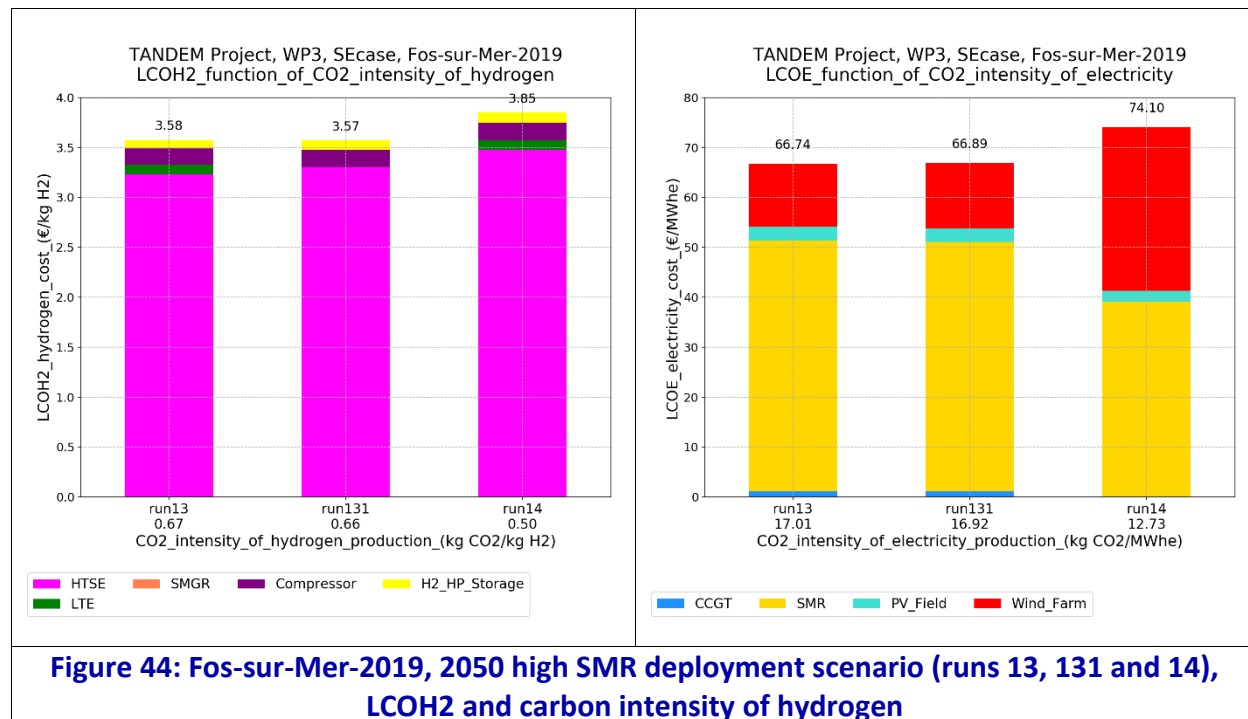
| 2050 scenario |                                 |                     |                           |                                |
|---------------|---------------------------------|---------------------|---------------------------|--------------------------------|
| Component     | Variable                        | run 13<br>base case | run131<br>("without-LTE") | run14<br>"without-fossil-fuel" |
| HTSE          | Mean hydrogen production (kg/h) | 8170                | 8260                      | 8144                           |
|               | Hydrogen production part        | 98.5%               | 100                       | 98.5%                          |
| LTE           | Mean hydrogen production (kg/h) | 622                 | 0                         | 566                            |
|               | Hydrogen production part        | 1.5%                | 0                         | 1.5%                           |

**Table 39: Fos-sur-Mer-2019, Main results for 2050-high SMR (run13, 14) cases**

Results of cases 13 and 131 are very similar. The NPV of the run131 is about 17 M€ higher than in the run13: The remove of LTE is globally balanced by more powerful HTSE and wind turbines

and a bigger hydrogen storage whereas a less powerful CCGT is calculated. In term of carbon intensities, the addition of one wind turbine is compensated by a lower CCGT capacity.

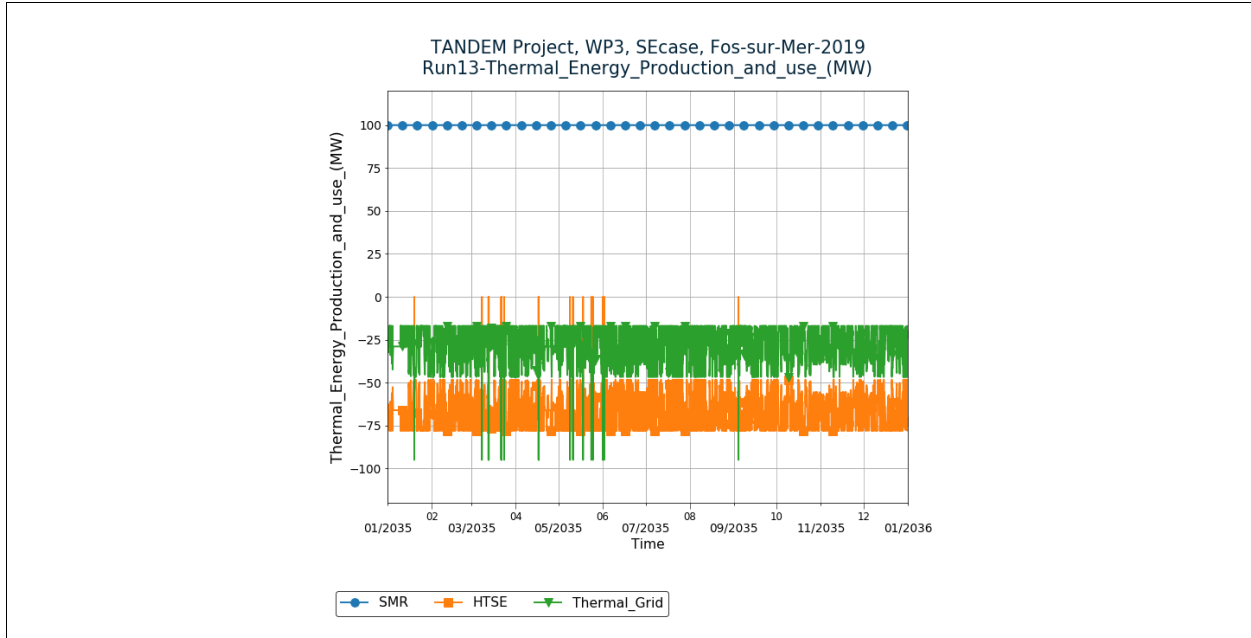
The **“without-fossil-fuel”** run14 leads to a very low carbon intensities (0.5 instead of 0.67 kg CO<sub>2</sub> eq/kg H<sub>2</sub>) for a more higher hydrogen cost (3.85 instead of 3.57 €/kg H<sub>2</sub>). The additional cost is mainly due to the increase in the size of the wind farm. As expected, the CCGT is no more used. The flexibility of the system is handled by the hydrogen storage. More electrical energy is sent to the grid (Figure 90). The LTE is little used and only when electricity is in excess.



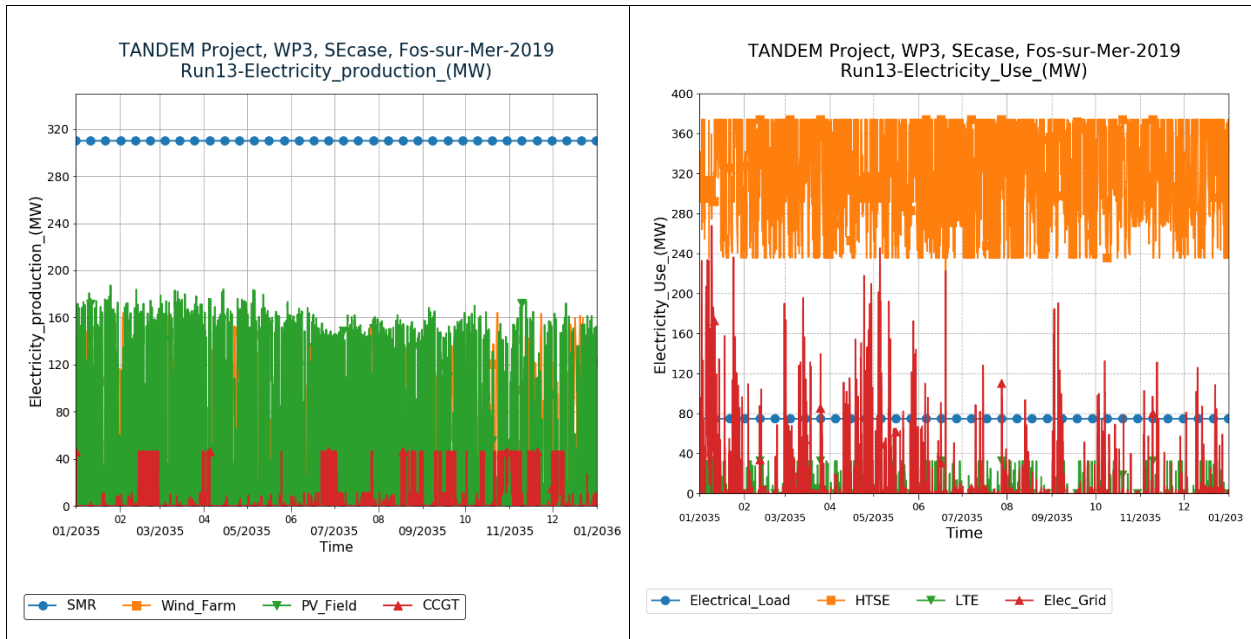
### 5.5.4 Focus on the E-SMR flexibility

In these first studies, the heat recovery taken into account as a reference is 9.26% with for two E-SMR units. In this context, and in particular, in the run13, thermal production is in excess compared to the HTSE needs, as it can be seen in Figure 45, whereas the E-SMR electricity production is limited to 310 MW<sub>e</sub>. Electricity needs are satisfied by adding the commitment of CCGT, essentially to make up the intermittent wind energy (Figure 46). The final objective is mainly to decrease of the CO<sub>2</sub> emissions for a cost closed to the reference case 13.

Figure 45 shows that, in the run13, about 20-45 MW<sub>th</sub> thermal energy are released towards the thermal grid and could be used to produce more electricity to avoid the commitment of the CCGT and to limit the size of the wind farm. Figure 46 shows also that a lot of wind farm energy production is released to the electrical grid. This electricity excess cannot be stored in the system.



**Figure 45: Fos-sur-Mer-2019, 2050 high SMR deployment scenario (run13), thermal production and consumption**



**Figure 46: Fos-sur-Mer-2019, 2050 high SMR deployment scenario (run13), electricity production and consumption**

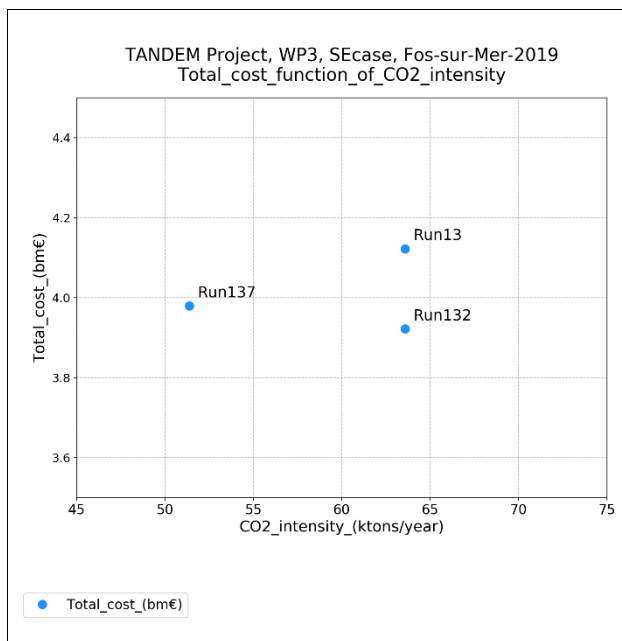
The purpose of the present focus is to analyse the possible flexibility of the E-SMR using the type 3 cogeneration model (see sections 2 and 5.2.4.1) by modulating and optimizing the E-SMR operation according to the thermal and electrical needs by decreasing the heat recovery and increasing the electrical supply. Optimization of the thermal energy could be also obtained by

the use of the thermal storage. Two additional runs (132 and 137) are conducted with the type 3 cogeneration model where the CO<sub>2</sub> emissions are limited at the run13 value for the run132 and a lower value for the run137. Results are summarized in the Table 40 and Figure 47 to Figure 50.

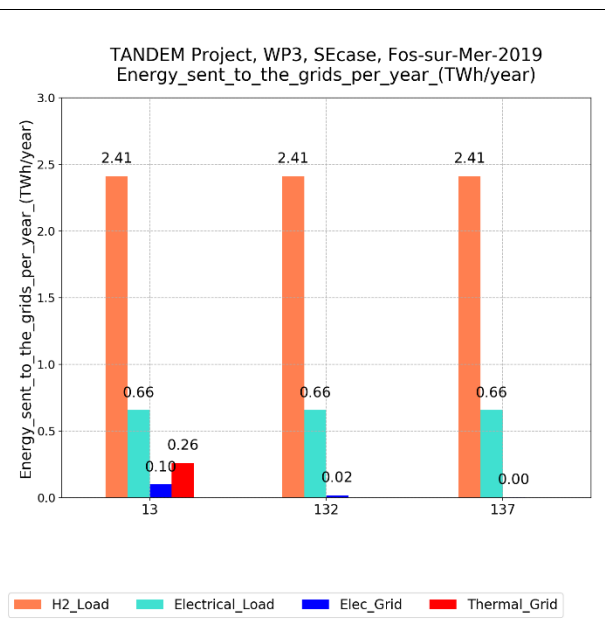
The type 3 cogeneration model activation shows the benefit of the flexibility of the E-SMR and the optimisation of the thermal and electrical energies. For lower CO<sub>2</sub> emissions obtained in run137 than in runs 13 and 132 (-20%), the costs are globally 3% lower (Figure 47). CO<sub>2</sub> intensities in electricity and hydrogen are also reduced (Figure 49 and Figure 50). For run132 and run137, the LCOH is increased as the thermal storage is used (Figure 51). In both calculations 132 and 137, no more electrical and thermal energies are released towards the grids (Figure 48).

|            | CO <sub>2</sub> emissions (ktons/year) | Total costs (M€) | LCOE (€/MWh <sub>e</sub> ) | LCOH (€/MWh <sub>th</sub> ) | LCOH <sub>2</sub> (€/kg H <sub>2</sub> ) | CI <sub>E</sub> (kg/MWh <sub>e</sub> ) | CI <sub>H</sub> (kg/MWh <sub>th</sub> ) | CI <sub>H<sub>2</sub></sub> (kg/kg H <sub>2</sub> ) |
|------------|--|------------------|----------------------------|-----------------------------|--|--|---|---|
| <b>13</b>  | 58.75026                               | 4122.4           | 66.74                      | 19.55                       | 3.57                                     | 17.00                                  | 1.00                                    | 0.67  |
| <b>132</b> | 58.75026                               | 3922.2           | 66.74                      | 21.11                       | 3.51                                     | 17.50                                  | 1.00                                    | 0.68  |
| <b>137</b> | 51.4159                                | 3979.6           | 67.39                      | 21.32                       | 3.58                                     | 14.16                                  | 1.00                                    | 0.55  |

**Table 40: Fos-sur-Mer-2019, E-SMR flexibility**



**Figure 47: Fos-sur-Mer-2019, E-SMR flexibility, Total costs function of the CO<sub>2</sub> emissions**



**Figure 48: Fos-sur-Mer-2019, E-SMR flexibility, energy sent to the grids**

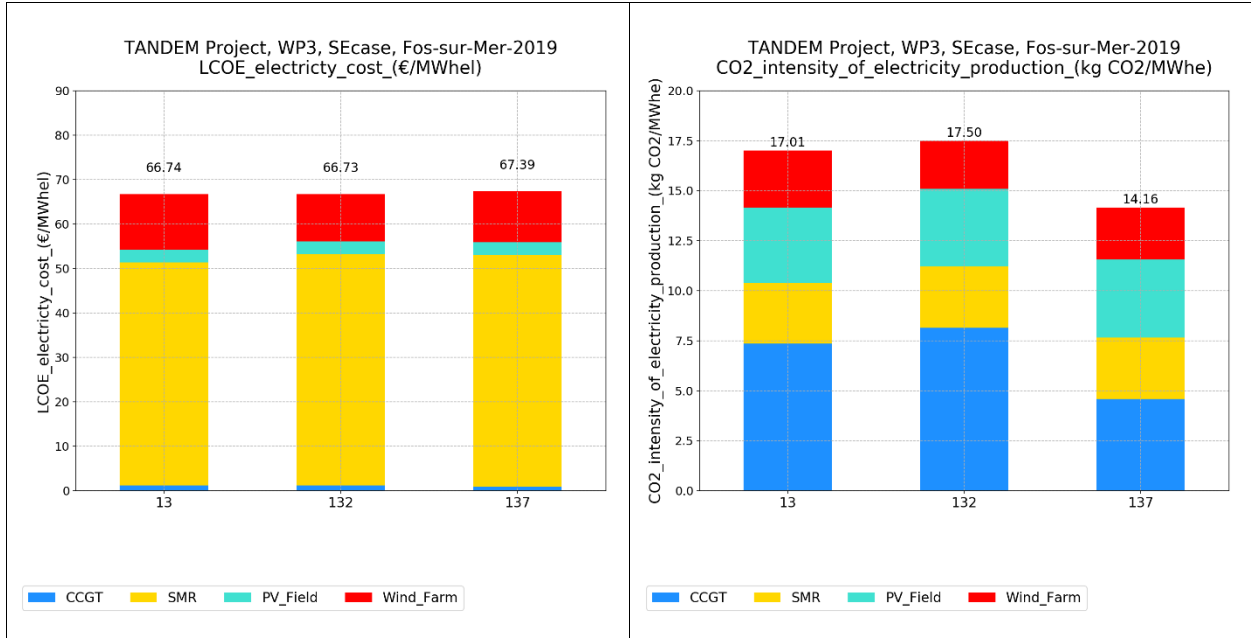


Figure 49: Fos-sur-Mer-2019, E-SMR flexibility, LCOE and CO<sub>2</sub> intensity

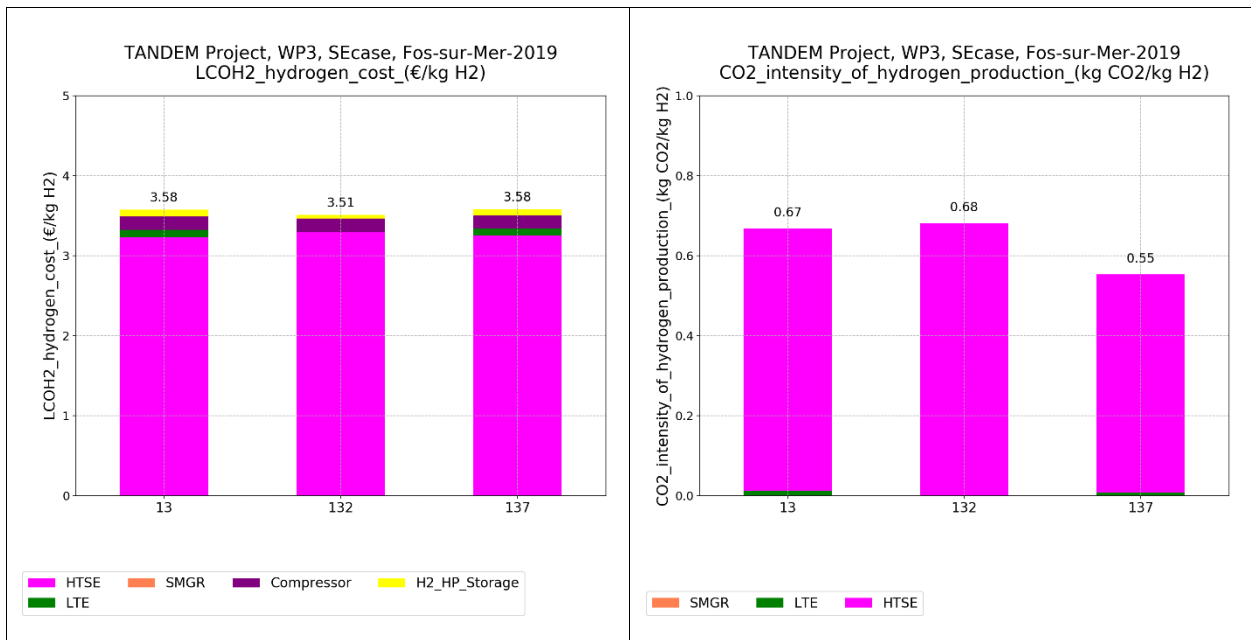
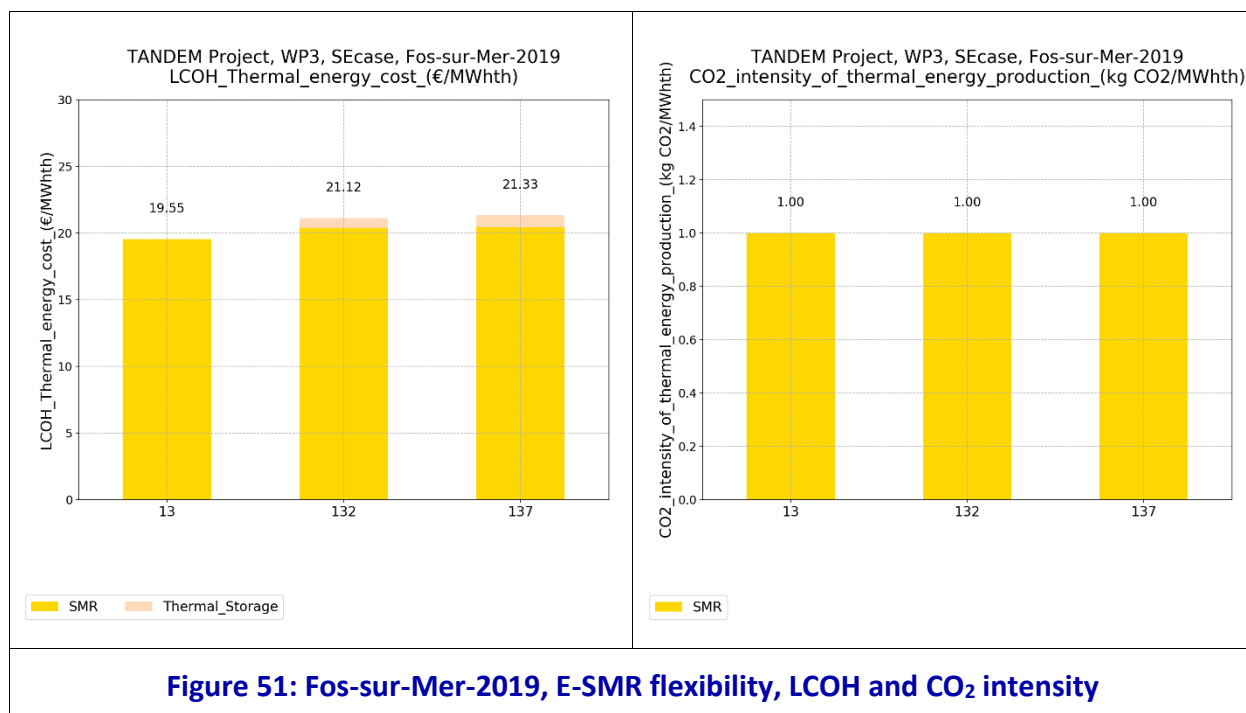


Figure 50: Fos-sur-Mer-2019, E-SMR flexibility, LCOH<sub>2</sub> and CO<sub>2</sub> intensity



In the following figures, the operation of the system is deeper analysed and detailed on a 7 days timeslot; the run13 (on the left of the figure) and 137 (on the right of the figure) are compared.

For both runs, the hydrogen production is stronger during the daytimes, as it can be seen on Figure 52. The Figure 53 shows the flexibility of the E-SMR. The electricity production is globally higher during daytimes due to renewable energies (solar and wind). In run 137, the E-SMR electrical production is reduced during daytimes as renewable energies are at maximum values. During nights, E-SMR electrical production becomes higher. In run 137, the flexibility of the E-SMR also leads to the limitation of the wind and CCGT commitments. During daytimes, the E-SMR thermal production (Figure 54 and Figure 55) is maximized to produce a maximum amount of hydrogen. At the same time, the heat storage is charged. Stored energy is discharged during nights when E-SMR thermal production becomes lower whereas a more electricity production is required.

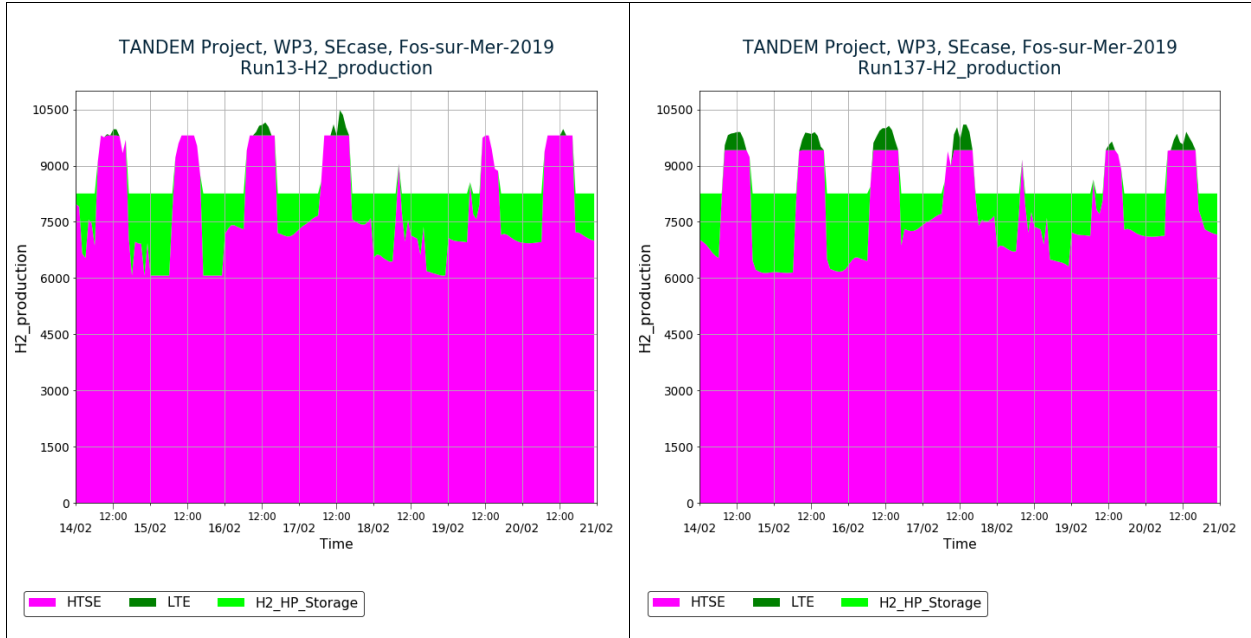


Figure 52: Fos-sur-Mer-2019, E-SMR flexibility, run13 and run137, hydrogen production

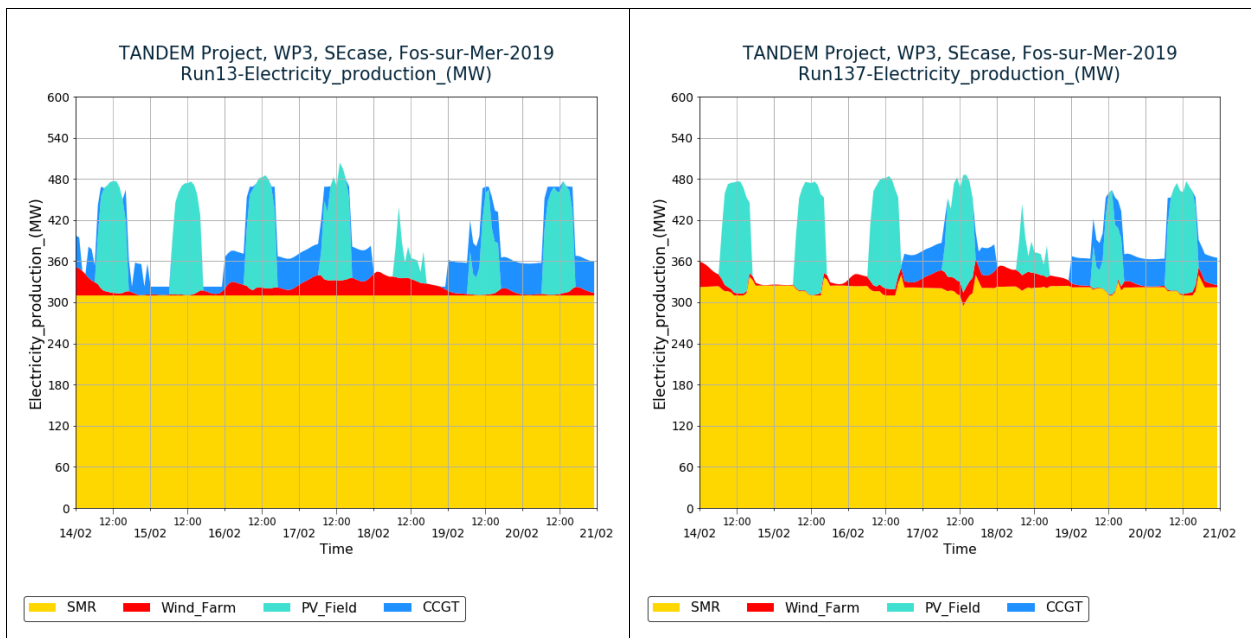


Figure 53: Fos-sur-Mer-2019, E-SMR flexibility, run13 and run137, electrical production

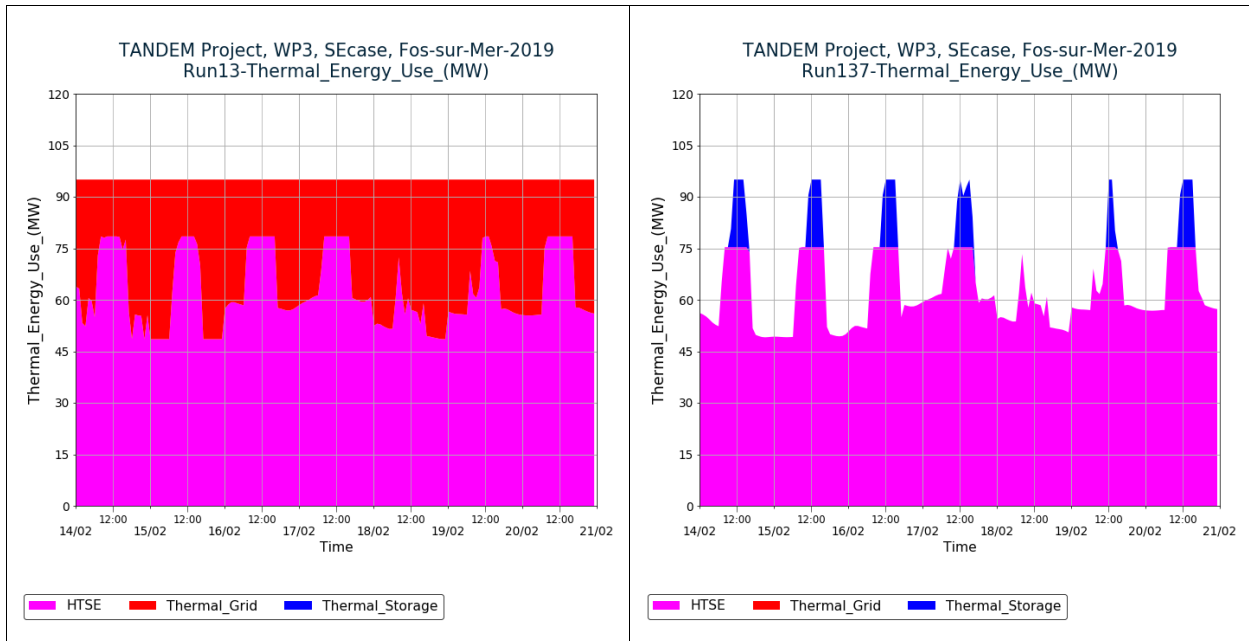


Figure 54: Fos-sur-Mer-2019, E-SMR flexibility, run13 and run137, thermal energy use

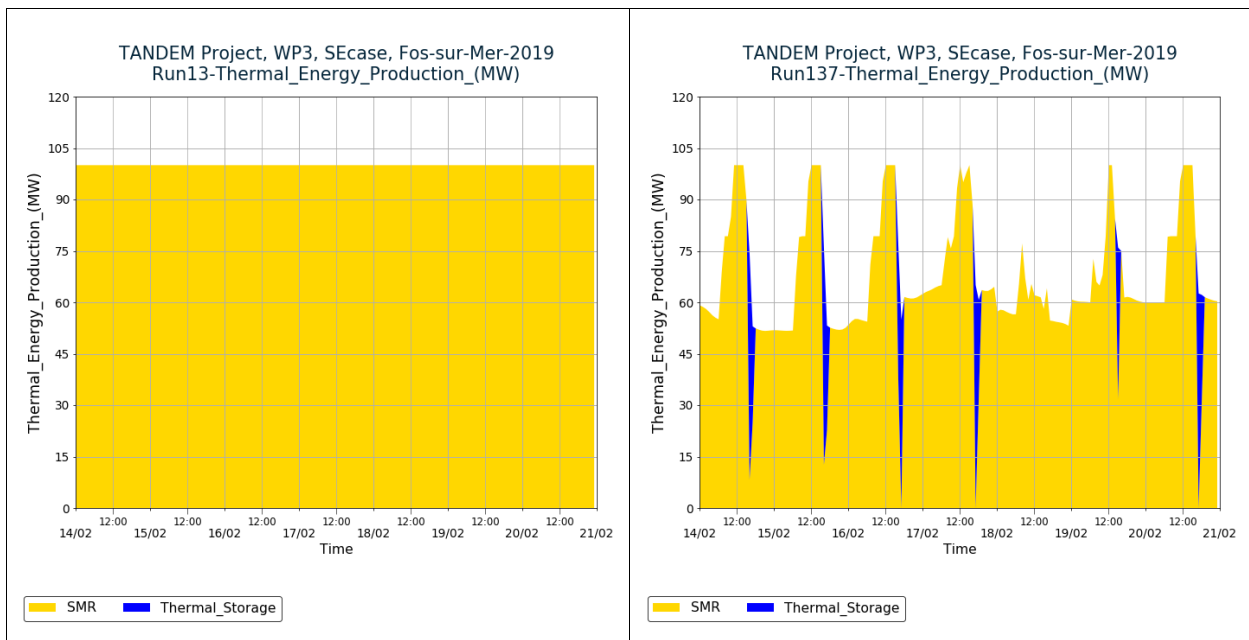


Figure 55: Fos-sur-Mer-2019, E-SMR flexibility, run13 and run137, thermal energy production

## 5.6 Conclusion

The purpose of this study is to investigate the techno-economic and environmental profitability of a NHES located in an industrialized harbour. Our project case is a system located close to Fos-sur-Mer harbour for which we have defined hydrogen and electricity needs.

The methodology used in the previous section has allowed to propose a decarbonisation scenario of the system. From a super-structure, several cases of interest were highlighted: the runs 5, 7 and 137. The PERSEE results of all calculations and the selected cases have shown the potentiality to decarbonize the electricity and the hydrogen productions with the help of SMR, electrolysis (mainly HTSE) and renewable energies (solar and wind).

The run 5 with only one E-SMR gives a decarbonisation at 29% but the CO<sub>2</sub> intensity of hydrogen remains higher than the CERTIFHy™ and European taxonomy thresholds.

The run 7 with two 2 E-SMR, the renewable energies and the HTSE shows that **the system can be decarbonized at about 80%**. The CO<sub>2</sub> intensity of hydrogen is lower than the CERTIFHy™ and European taxonomy thresholds. The LCOE and the LCOH<sub>2</sub> are respectively close to 61 €/MWh<sub>e</sub> and 3.2 €/kg H<sub>2</sub>. **The extra cost of the decarbonisation for the hydrogen production is about 26.1 €/MWh<sub>e</sub> and 2.2 €/kg H<sub>2</sub>** compared with the “business as usual” hydrogen production mean (SMGR, the run0). A carbon cost of 100 €/ton CO<sub>2</sub> eq would lead to the same LCOE between run 0 and run 7 whereas a carbon cost of 172 €/ton CO<sub>2</sub> eq would lead to the same total costs between run 0 and run 7 thus to very similar LCOE, LCOH, LCOH<sub>2</sub> (as the outputs are nearly identical). It is worth mentioning that the cost of CO<sub>2</sub> reached more than 100 €/ton CO<sub>2</sub> in February 2023.

**A 94% decarbonisation rate is obtained a two flexible E-SMR set (case137).** In this case, **the extra cost of the decarbonisation is about 6€/MWh<sub>e</sub> and 0.4 €/kg H<sub>2</sub> compared with the run 7.**

## 5.7 Perspectives for further sensitivity studies to be performed

Sensitivity analysis may be conducted as the study is based on a lot of assumptions and as some of the input data may be questioned and as the results of the operation have suggested ways of improvement in the decarbonisation process. These sensitivity studies could concern:

### About the “ways to increase the decarbonisation process”

- Regarding the architecture of the case, the CCS was not taken into account whereas it would have been more realistic to consider it.
- Fossil energies (CH<sub>4</sub>, CCGT) are always used in the decarbonized solutions.

They can be removed either by adding electrical battery and increasing the limits of the PV field, the wind farm and the hydrogen storage or by using the hydrogen local production and adding fuel cells or hydrogen engines. Another option could be to use the unused thermal energy to store it and to produce electricity owing to an Organic Rankine Cycle (ORC).

### **About the assumptions used for the input data**

- Uncertainties of E-SMR input data are identified. Sensitivity calculations could be carried out on the technical (heat recovery ratio), economical (CAPEX, variable costs) and environmental data (CO<sub>2</sub> intensity).
- The natural gas (CH<sub>4</sub>) is a key parameter in the optimisation process as it is in competition with all others costs. The year 2019 has been seen favourable whereas the year 2022 is less favourable.
- The base assumption is the harbour located closed to Fos-sur-mer with the associated renewable energies (solar, wind) and natural gas price. Additional calculations could be done on other locations to validate the global methodology.
- The study is performed with given loads. Sensitivity analysis could be run by modifying the hydrogen load (profile, amount) and the electrical/hydrogen load sharing.
- In our calculations, solutions with renewable energies coupled to a LTE never appeared in the optimal solutions found by PERSEE. This can be due to favourable data costs for HTSE. Calculations with lower CAPEX of PEM electrolyser associated to greater PV field and wind farm would be interesting to compare the calculated costs and CO<sub>2</sub> emissions.

## **6 Central European case**

Document “Czech SMR Roadmap Applicability and Contribution to Economy” [69] proposes to take advantage of SMR power units to suitable replace of coal-fired units and large CHP plants with the aim of decarbonising them. In the context of high-performance large-scale nuclear or, conversely, climate-dependent renewables, SMRs are potentially the missing link between the two, capable of providing both stable power output and a degree of flexibility similar to today’s coal-fired sources. This implies a degree of decentralisation for SMRs on a local scale at the level of industry, cities and regions, e.g., for the heating sector in conjunction with district heating networks. In the future, they can, together with renewables, form a “backbone of the European zero carbon energy system”, while requiring lower backups and reserves, compared to sources at the power level of 1 GWe and above.

For inclusion of the SMR technology in spatial development policies and plans of the Czech Republic it is a prerequisite introduction of the SMR technology into following strategic

documents: the State Energy Policy (SEP) [65], the National Action Plan for the Development of Nuclear Sector in the Czech Republic (NAP NE) [67] and the Radioactive Waste and Spent Nuclear Fuel Management Policy.

Three scenarios were originally defined in accordance with D3.1 to cover timeframes for 2035 and 2050 as follows:

- ⇒ District Heating with Low SMR deployment Scenario 2035,
- ⇒ District Heating with High SMR deployment Scenario 2035,
- ⇒ District Heating with High SMR deployment Scenario 2050.

But in December 2023 the European Commission (EC) published its assessments of the draft revised National Energy and Climate Plans submitted by Member States. The EC encouraged to have a look at this assessment, especially since there is room for improvements in the way countries have drafted their plans in terms of research, innovation, and competitiveness. On 6 February the EC published a 2040 Climate Target Communication, with an impact assessment on possible ways to decarbonise the EU by 2050, with a recommendation of a 90% net greenhouse gas emissions reduction by 2040 compared to 1990 levels. Considering these EC documents and taking into account the Czech Republic's Hydrogen Strategy and Czech SMR Roadmap Applicability and Contribution to Economy, the Central European Case (CEC) was enlarged by an assessment of possibility of creation of Hydrogen valley to meet requirements of the EC 2040 Climate Target Communication in the selected CE region.

Then the aim of the CEC is to propose a way to:

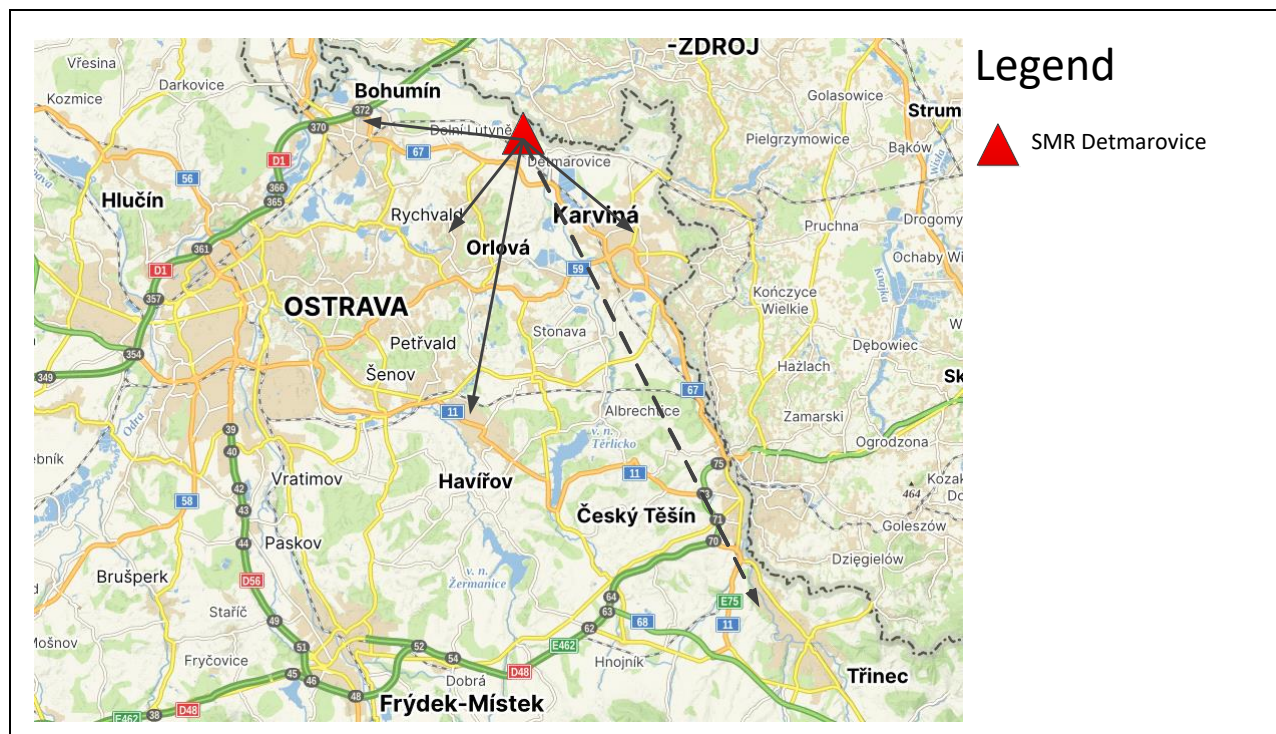
- Replacement of a part of coal heat sources using the example of part of the territory of the Moravian-Silesian Region (MSR) of the CR with low-emission SMR sources and thus decisively reduce polluting emissions in the MSR,
- Assessment of a potential of Hydrogen production for industrial application – establishment of “Hydrogen valley” in the selected territory of the MSR.

It should be noted, that MSR is a highly industrialized region with a large share of CO<sub>2</sub> emission in the CR. The supply of heat and electricity to the population and industry comes mainly from fossil fuel sources. The most significant polluters are mainly large stationary sources e.g. iron and steel works (Trinec, Vitkovice and Ostrava), power plants (Detmarovice and Trebovice) and heating plants (Karvina and CSA). The selected territory is partially surrounded by the Polish and Slovak border and therefore appropriately represents the area of the Central Europe. The results of the CEC can be easily utilized as for the territory of Silesian Voivodeship in Poland, which is similar industrial region as the Moravian-Silesian Region, as for Žilina self-governing region in the Slovak Republic.

Assessed model scenarios are of a working nature for the purposes of the TANDEM project and do not have the ambition to define real future plans for the construction of nuclear energy sources in the CR. They only illustrate the possible future utilization and decarbonisation of selected district heating networks (DHN).

### 6.1 General presentation of the case

The CEC analyses the integration of LW-SMRs in hybrid system configurations incorporating district heating networks, an electricity grid and hydrogen production using PEM technology. The aim of the CEC is to propose a way to replace a part of coal sources in the selected territory of the CR with up to four SMR units. Three coal-fired sources were chosen for the replacement: Karvina and CSA heating plants, which are connected to Karvina/Havirov DHN (hereinafter referred to as KH DHN) and Detmarovice power plant, which is connected to Bohumin/Orlova DHN (hereinafter referred to as BO DHN) and to Trinec DHN (hereinafter referred to as T DHN). Since these DHNs are in the vicinity, they are for the study case interconnected and heated by SMR deployed in Detmarovice site, as shown in Figure 56.



**Figure 56: Interconnection of several DHNs for Detmarovice site**

The Central European Case assesses and compare following scenarios which take into consideration decarbonisation plans of the CR (detailed descriptions of each scenario are described in chapters 6.3, 6.4, 6.5 and 6.6):

- ⇒ **District Heating with Low SMR deployment Scenario 2035:** Current coal sources are replaced by new ones with similar performance parameters. This scenario is hereinafter referred to as L35 and its architecture is shown in Figure 57.

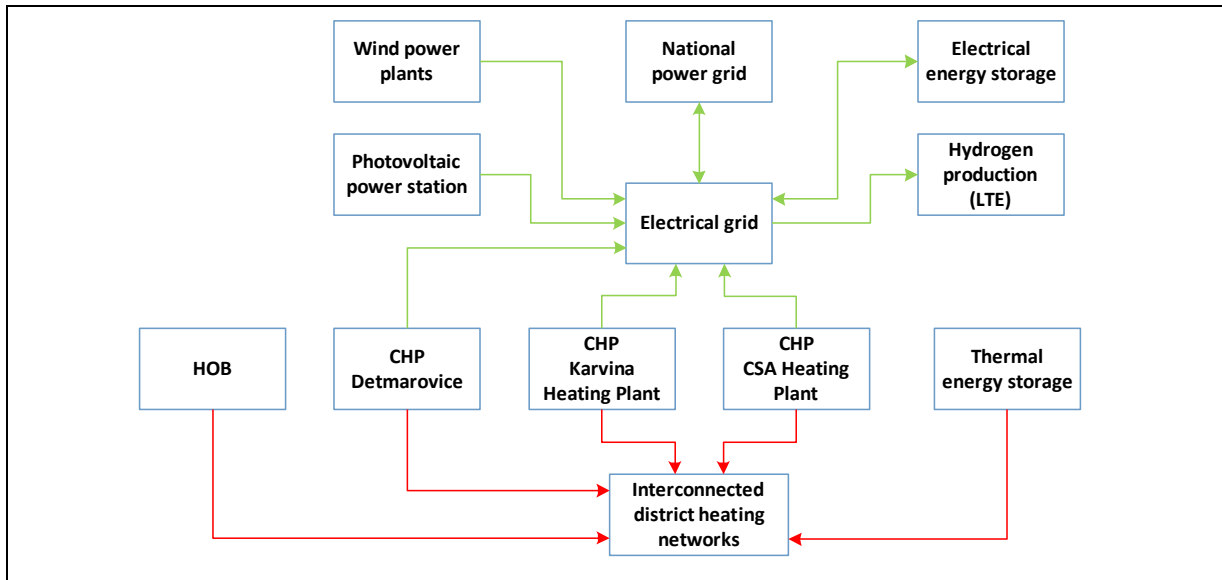


Figure 57: CEC Low Scenario 2035

- ⇒ **District Heating with High SMR deployment Scenario 2035 – 1 SMR:** Detmarovice power plant is replaced by one SMR unit, Karvina and CSA heating plants are replaced by new coal power units with similar performance parameter. This scenario is hereinafter referred to as H35–1SMR. Architecture is shown in Figure 58.

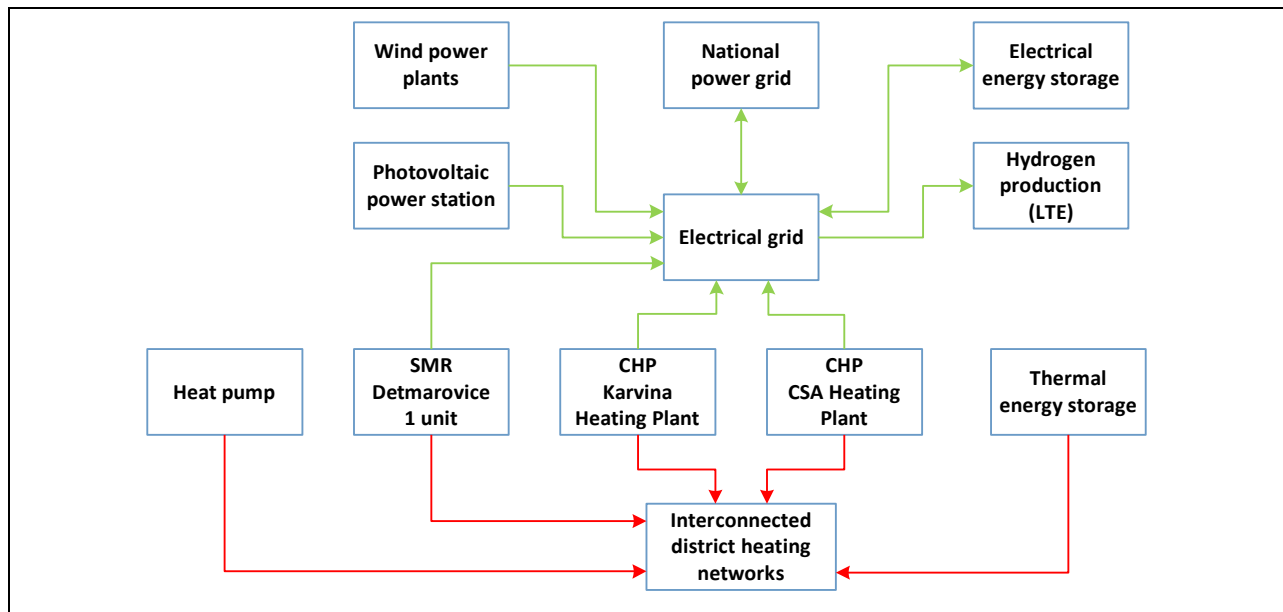
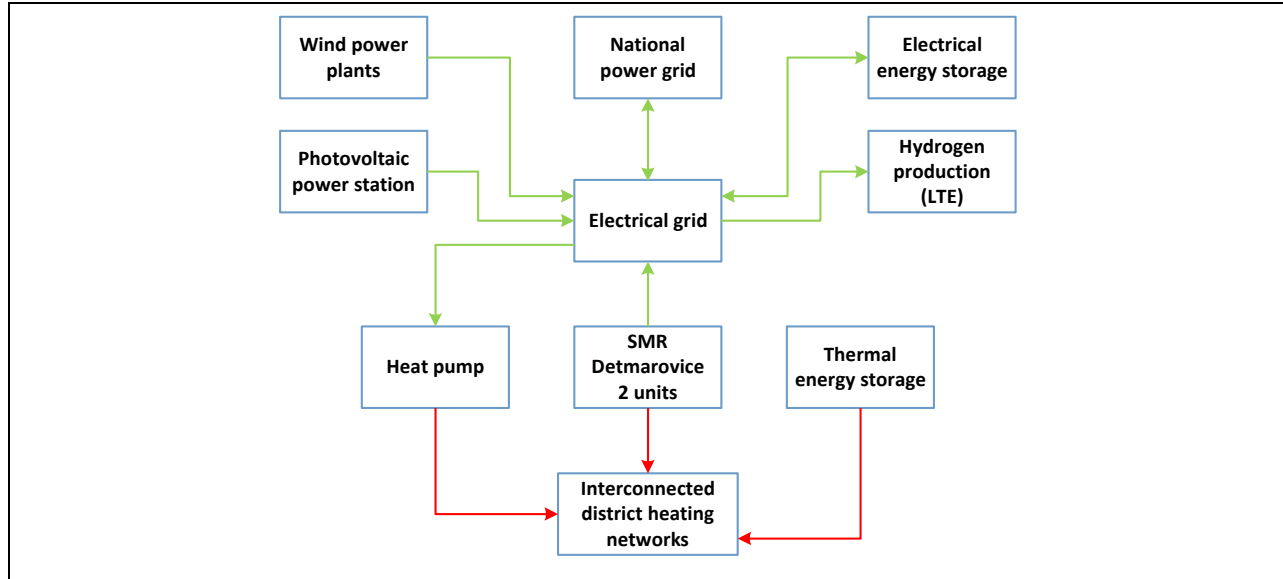


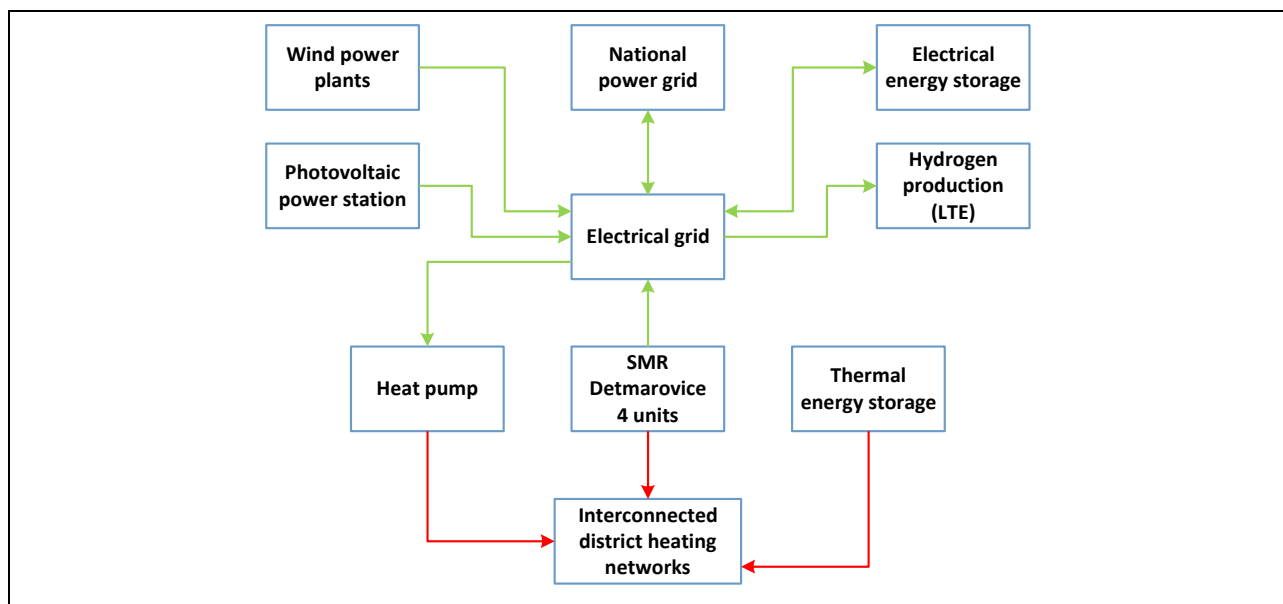
Figure 58: CEC High Scenario 2035 with deployment of 1 SMR unit

- ⇒ **District Heating with High SMR deployment Scenario 2035 – 2 SMRs:** All coal combustion sources are replaced by two SMRs in Detmarovice site in 2035 to provide heat for households, industry and electricity for hydrogen production. This scenario is hereinafter referred to as H35–2SMR. Analysed architecture is depicted in Figure 59.



**Figure 59: CEC High Scenario 2035 with deployment of 2 SMR units**

- ⇒ **District Heating with High SMR deployment Scenario 2050:** Four SMRs are in operation in Detmarovice site to meet requirements for long term decarbonisation and higher hydrogen production in the CR. This scenario is hereinafter referred to as H50-4SMR, architecture of this scenario is in Figure 60.



**Figure 60: CEC High Scenario 2050**

## 6.2 General and techno-economic assumptions

This chapter describes all assumptions that are used in analysed CEC scenarios. Therefore, there are some information about following general and economic assumptions. Description of the methodology adopted to assess economic and environmental computations is presented in Chapter 4.

This chapter also contains a short description of the considered components with parameters taken into account in the modelling. The architecture of the HES is composed of following energy components:

- Combined heat and power plant,
- Heat only boiler,
- Small modular reactor,
- Heat pump,
- Renewable resources,
- Hydrogen production,
- Hydrogen storage,
- Thermal energy storage,
- Electrical energy storage,
- District heating networks.

### 6.2.1 PERSEE assumptions

CEC scenarios are modelled by PERSEE software (version 3.8.7) developed and provided by CEA for the purposes of the TANDEM project. An open-source solver CLP [71] was used as a code for solving linear programming problems.

### 6.2.2 Economic Data assumptions

Economic values of all components are expressed in the € of 2023 rate. There is no estimation of price levels as in 2035 or as in 2050 with assumption that differences between technology economic values of particular power technologies will stay relatively stable. Therefore, publicly available data sources were used to provide possibility to check origin of these data and to understand their inherent relation. Technology specific economic data are based on OECD NEA report “The Role of Nuclear Power in the Hydrogen Economy: Cost and Competitiveness” [4]. The report focuses in particular on the medium term, set as 2035, a time horizon identified as the turning point in global hydrogen strategies. Economic values used in the report [4] are expressed in 2020 USD. The technology economic values used in the CEC are expressed in 2023 € recalculated by inflation factor value of 1.1597. Using of these economic values featured with high inherent consistency eliminates a possible risk of data uncertainty of values obtained from

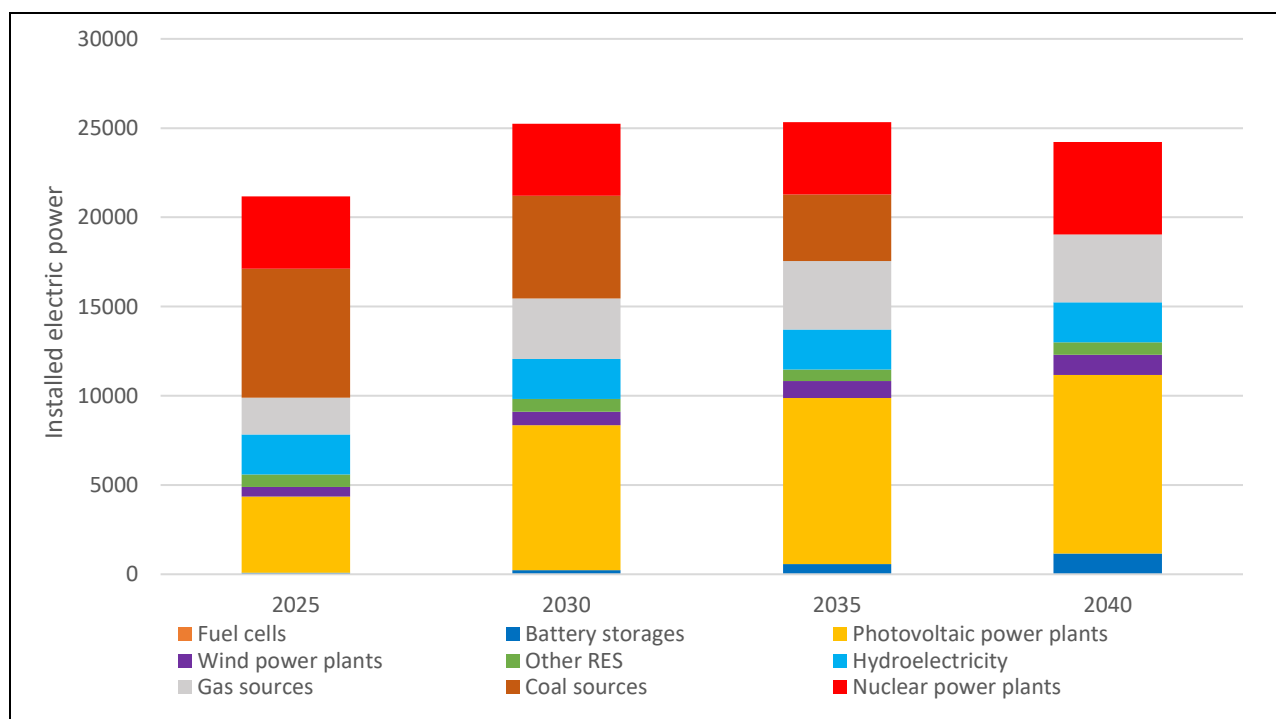
different incompatible sources. Nevertheless, some conservative technology economic values (e.g. for nuclear) are used from Lazard's 2023 report [5].

The CEC modelled through PERSEE can buy coal through market, natural gas through a natural gas grid and it can sell electricity through an electricity network. Commodity prices of coal, electricity, gas etc. origin from web page Kurzy.cz [72] and price of heat from pricelist of Detmarovice CHP [73].

In CEC study, 20 years economic lifetime is considered with the discount rate of 7%.

### 6.2.3 Electricity production

The CEC takes into account one of the possible scenarios of the electricity development predicted in Resource Adequacy Assessment of the Power Grid of the Czech Republic until 2040 [68]. Selected Conservative scenario predicts what consumption can be conservatively assumed in the future, taking into account the currently known strategies, visions and plans of the Government of the CR. The conservative prediction assumes such a development of the electricity sector, which envisages the fulfilment of the EU's climate objectives, transformation and modernization of the sector, while emphasizing self-sufficiency and reliability of electricity supply. Figure 61 shows the installed capacity in the conservative prediction for years 2025, 2030, 2035 and 2040.



**Figure 61: Installed capacity in the Conservative Prediction for individual years and resource categories (ČEPS, 2022)**

## 6.2.4 Combined heat and power Plant

### 6.2.4.1 CHP Elektrarna Detmarovice (Elektrárna Dětmárovice, a.s.)

The Detmarovice Power Station is situated near the city of Ostrava, in the immediate vicinity of the Polish border. It has an installed capacity of 600 MW<sub>e</sub>. The project got commissioned in May 1975 and is currently owned by CEZ, which is one of the largest companies in the CR and a leader in Czech energy sector. The plant is being used for electricity production and heat generation that supplies mainly the towns of Bohumin and Orlova. The primary fuel being used to power the plant is coal, which is procured from Ostrava-Karvina Mines.

### 6.2.4.2 CHP Teplarna Karvina (Veolia Energie ČR, a.s. - Teplárna Karviná)

Karvina power station is an operating power station of 55 MW<sub>e</sub> sited in city Karvina. It began operating in 1970 and is owned by French transnational company Veolia Group. The plant is being used for the electricity production, but its main purpose is to supply heat to the towns Karvina and Havirov.

### 6.2.4.3 CHP Teplarna CSA (Veolia Energie ČR, a.s. - Teplárna ČSA)

The Teplarna CSA heating plant is coal technology with a 24 MW<sub>e</sub> power. The unit was commissioned in 1951 in Karvina and went through significant upgrades to continue operating to the present day. It is also owned by Veolia and together with Karvina heating plant are connected in one district heating network.

### 6.2.4.4 New CHP sources modelled in the HES

Since the above-mentioned currently used coal sources are already obsolete, their use after 2035 cannot be assumed. Therefore, the study assumes their replacement (only in reference scenario L35 and H35-1SMR) by new sources with similar parameters.

|                             | Parameter name                             | Value | Unit             |
|-----------------------------|--|-------|------------------|
| New Detmarovice Power Plant | Thermal power capacity                     | 1555  | MW <sub>th</sub> |
|                             | Electrical power capacity                  | 600   | MW <sub>e</sub>  |
|                             | Max. efficiency for electricity production | 38    | %                |
|                             | Max. effective heat recovery capacity      | 3     | %                |
| New Karvina Heating Plant   | Thermal power capacity                     | 248   | MW <sub>th</sub> |
|                             | Electrical power capacity                  | 87    | MW <sub>e</sub>  |
|                             | Max. efficiency for electricity production | 35    | %                |
|                             | Max. effective heat recovery capacity      | 52    | %                |

| Parameter name                 |  | Value     | Unit                          |
|--------------------------------|--|-----------|-------------------------------|
| New CSA Heating Plant          | Thermal power capacity                     | 171       | MW <sub>th</sub>              |
|                                | Electrical power capacity                  | 60        | MW <sub>e</sub>               |
|                                | Max. efficiency for electricity production | 35        | %                             |
|                                | Max. effective heat recovery capacity      | 52        | %                             |
| Ratio heat/electricity         |  | variable  | %                             |
| Load following range           |  | 40 - 100  | %                             |
| Speed of load following        |  | 2         | %Pn/min                       |
| In-House plant consumption     |  | 4         | %                             |
| Fuel material                  |  | Coal      | -                             |
| Starting time                  |  | 5         | hour                          |
| Direct CO <sub>2</sub> content |  | 2.7019    | kg CO <sub>2</sub> eq/kg coal |
| Grey CO <sub>2</sub>           |  | Neglected | kg CO <sub>2</sub> eq/MW      |
| Design lifetime                |  | 40        | Years                         |
| CAPEX                          |  | 2502      | €/kW <sub>e</sub>             |
| OPEX                           |  | 2.41      | %/CAPEX                       |
| Variable costs                 |  | 11        | €/MWh                         |

**Table 41: CHP parameters used in CEC study**

Note: In CEC study, the CHPs operate at full load in cogeneration mode of type 3 with load following.

### 6.2.5 Heat only boiler

Unlike CHP described above which produce thermal energy as a by-product of electricity generation, Heat Only Boiler (HOB) in CEC is specifically dedicated to generating thermal energy for district heating applications.

| Parameter name                 | Value       | Unit                     |
|--------------------------------|-------------|--------------------------|
| Thermal power capacity         | 47.5        | MW <sub>th</sub>         |
| Electrical power capacity      | 0           | MW <sub>e</sub>          |
| Efficiency for heat production | 94.7        | %                        |
| Fuel material                  | Natural Gas | -                        |
| Direct CO <sub>2</sub>         | 2.4747      | kg CO <sub>2</sub> eq/kg |

| Parameter name       | Value     | Unit                     |
|----------------------|-----------|--------------------------|
| Grey CO <sub>2</sub> | Neglected | kg CO <sub>2</sub> eq/MW |
| Design lifetime      | 30        | Years                    |
| CAPEX                | 852       | €/kW <sub>e</sub>        |
| OPEX                 | 1         | %/CAPEX/year             |
| Variable costs       | 5         | €/MWh                    |

**Table 42: HOB parameters used in CEC study [75]**

### 6.2.6 Small Modular Reactor

The data for the SMR component are taken from the ELSMOR project. The E-SMR is a LW-SMR reaching 540 MW<sub>th</sub>/170 MW<sub>e</sub> at nominal power. For the CEC back-pressure turbine is applied for electricity production with means of heat extraction for district heating. Since heat supplied from SMR units to BO DHN, KH DHN and T DHN only needs limited temperature (considered between 100°C and 150°C), steam from turbine is extracted from the low-pressure turbine. For these reasons, the secondary circuit is modified to improve heat production while slightly reducing the maximum efficiency of electricity production. Therefore, the heat recovery is increased to 55 % resulting in maximum heat delivery of 281 MW<sub>th</sub> with reduced electrical output to 107 MW<sub>e</sub>.

| Parameter name                             | Value    | Unit             |
|--|----------|------------------|
| Thermal power capacity                     | 540      | MW <sub>th</sub> |
| Electrical power capacity                  | 162      | MW <sub>e</sub>  |
| Max. efficiency for electricity production | 30       | %                |
| Max. effective heat recovery capacity      | 52       | %                |
| Rate heat/electricity                      | variable | %                |
| Thermal power at 100% hybridization        | 281      | MW <sub>th</sub> |
| Electrical power at 100% hybridization     | 107      | MW <sub>e</sub>  |
| Load following range                       | 20 - 100 | %                |
| Speed of load following                    | 5        | %Pn/min          |
| In-House plant consumption                 | 10       | %                |
| Fuel cost <sup>7</sup>                     | 1397     | €/kg             |

<sup>7</sup> Value is approximate and as September 2021 from [76]

| Parameter name              | Value | Unit                |
|-----------------------------|-------|---------------------|
| CAPEX                       | 6050  | €/kW <sub>e</sub>   |
| OPEX <sup>8</sup>           | 1.55  | %/CAPEX/year        |
| Variable costs <sup>9</sup> | 3.2   | €/MWh <sub>th</sub> |

**Table 43: SMR parameters used in CEC study**

Note: In CEC study, the SMRs operate at full load in cogeneration mode of type 3 with load following.

### 6.2.7 Renewable resources

The outlook for development of the net installed capacity of renewable energy sources is considered according to Conservative Scenario in [68] (see Figure 61). Photovoltaic sources should have a share of 36.57% in the total installed electricity power in the CR in 2035. The installed capacity of PV 415.76 MW<sub>e</sub> corresponds to this share in CEC HES (corresponds to the proportional value of the replaced coal resources with the installed capacity 680 MW<sub>e</sub>). PV load for this installed power was obtained from Photovoltaic Geographical Information System [29]. PV placement was set in the middle of HES (49.8434, 18.3877).

| Parameter name            | Value  | Unit                                   |
|---------------------------|--------|--|
| Electrical power capacity | 415.76 | MW <sub>e</sub>                        |
| Grey CO <sub>2</sub>      | 48     | kg CO <sub>2</sub> eq/MWh <sub>e</sub> |
| Design lifetime           | 25     | Years                                  |
| CAPEX                     | 1185   | €/kW <sub>e</sub>                      |
| OPEX                      | 1      | %/CAPEX/year                           |

**Table 44: PV parameters used in CEC study**

Similarly to PV, the outlook for the development of the net installed capacity of wind power plants is considered according to Figure 61. Wind sources should have a share of 3.71 % in the total installed electricity power in the CR in 2035. The installed capacity of 42.17 MW<sub>e</sub> wind energy corresponds to this share in CEC HES. The wind farm placement for Renewables.ninja [28] computation is on suitable location for wind power plants in the vicinity of HES (49.960165, 18.24726). The Vestas V 112 type with an electric 3.3 MW<sub>e</sub> output power was selected as default power plant.

<sup>8</sup> OPEX value is from [4]

<sup>9</sup> Variable cost is related to the thermal input power, value is from [4]

| Parameter name            | Value | Unit                                   |
|---------------------------|-------|--|
| Electrical power capacity | 42.17 | MW <sub>e</sub>                        |
| Grey CO <sub>2</sub>      | 11    | kg CO <sub>2</sub> eq/MWh <sub>e</sub> |
| Design lifetime           | 15    | Years                                  |
| CAPEX                     | 2956  | €/kW <sub>e</sub>                      |
| OPEX                      | 1.95  | %/CAPEX/year                           |

**Table 45: Wind power plant parameters used in CEC study**

Since the conservative scenario in [68] does not foresee a large increase in installed electric power in the following years after 2035, the same power parameters of renewable energy sources are considered for H50-4SMR.

### 6.2.8 Heat pump

Excess electrical capacities of nuclear and especially of renewable energy sources can be converted into heat, and thus used more efficiently. The large-scale industrial heat pump for district heating with characteristics similar to (e.g. SHP-C600, C750 from Siemens [74]) is also incorporated in CEC HES. Industrial heat pumps are an efficient and cost-effective solution for the generation of heat.

| Parameter name                | Value     | Unit                                   |
|-------------------------------|-----------|--|
| Maximum thermal heating power | 40        | MW <sub>th</sub>                       |
| Minimum thermal heating power | 15        | MW <sub>th</sub>                       |
| Speed of ramp up              | 5         | %/min                                  |
| Speed of ramp down            | 10        | %/min                                  |
| Grey CO <sub>2</sub>          | Neglected | kg CO <sub>2</sub> eq/MWh <sub>e</sub> |
| Design lifetime               | 20        | Years                                  |
| CAPEX                         | 820       | €/kW                                   |
| OPEX                          | 2         | %/CAPEX/year                           |

**Table 46: Large scale industrial heat pump parameters used in CEC study**

### 6.2.9 Hydrogen production

The Czech Republic's Hydrogen Strategy [70] is being developed in the context of the Hydrogen Strategy for a climate neutral Europe, which reflects the European Green Deal objective of

climate neutrality by 2050. The objective of the Strategy is thus to reduce greenhouse gas emissions in such a way that the economy shifts smoothly to low-carbon technologies.

The studied HES represents 4.5 % of the total installed capacity in the CR in 2035 and 2050. The amount of hydrogen produced in the studied scenarios corresponds proportionally to the predictions of the H<sub>2</sub> demand given in Czech hydrogen strategy (Table 47).

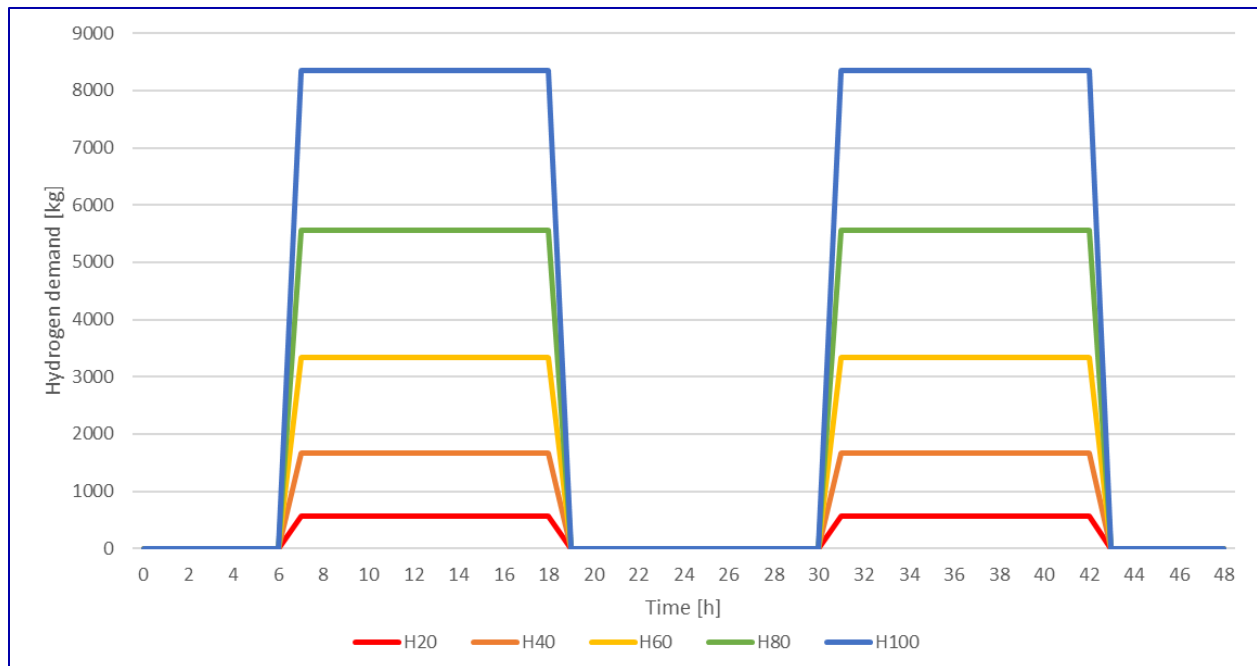
| Parameter                            | Year | Value     | Unit   |
|--------------------------------------|------|-----------|--------|
| Low carbon hydrogen demand in the CR | 2035 | 273 000   | t/year |
|                                      | 2050 | 1 728 000 | t/year |

**Table 47: Low carbon hydrogen demand in CR [70]**

The constraints for hydrogen production are set from 20% (considered the minimum that should be produced directly from the electricity grid in the CR) up to a value of 100%. This corresponds to the hydrogen production requirements given in the Table 48 and represented in Figure 62.

| Parameter   | Marking | %   | Value  | Unit   |
|---|---------|-----|--------|--------|
| 4.5 % of low carbon hydrogen demand in the CR in 2035 | H20     | 20  | 2 436  | t/year |
|   | H40     | 40  | 4 872  | t/year |
|   | H60     | 60  | 7 308  | t/year |
|   | H80     | 80  | 9 744  | t/year |
|   | H100    | 100 | 12 180 | t/year |
| 4.5 % of low carbon hydrogen demand in the CR in 2050 | H20     | 20  | 15 552 | t/year |
|   | H40     | 40  | 31 104 | t/year |
|   | H60     | 60  | 46 656 | t/year |
|   | H80     | 80  | 62 208 | t/year |
|   | H100    | 100 | 77 760 | t/year |

**Table 48: Constraints for hydrogen production in studied scenarios**



**Figure 62: Intermittent demand for hydrogen**

### 6.2.9.1 Electrolyser

Proton Exchange Membrane (PEM) electrolyzers are implemented in the HES for hydrogen production. Although PEM electrolyzers are more expensive compared to the alkaline electrolyser, they have a number of advantages that suit the CEC better:

- PEM electrolyzers have higher current densities, allowing them to adapt to rapid changes in power that could be caused by a tightly coupled nuclear–renewable HES.
- PEM electrolyzers can provide frequency control and voltage regulation because of their ability to ramp very quickly.
- PEM electrolyzers have higher output pressure.

| Parameter name         | Value                              | Unit   |
|------------------------|------------------------------------|--|
| Maximum nominal power  | According to H <sub>2</sub> demand | MW   |
| Minimum power          | 5                                  | % of nominal power                             |
| Output pressure        | 45                                 | bar  |
| Electrical consumption | 53                                 | kWh <sub>e</sub> /kg H <sub>2</sub> produced   |
| Heat consumption       | Neglected                          | kWh <sub>th</sub> /kg H <sub>2</sub> produced  |
| Water consumption      | Neglected                          | kg H <sub>2</sub> O/kg H <sub>2</sub> produced |
| Start-up time          | 1                                  | minute   |
| Ramp rate              | 10                                 | %/s  |

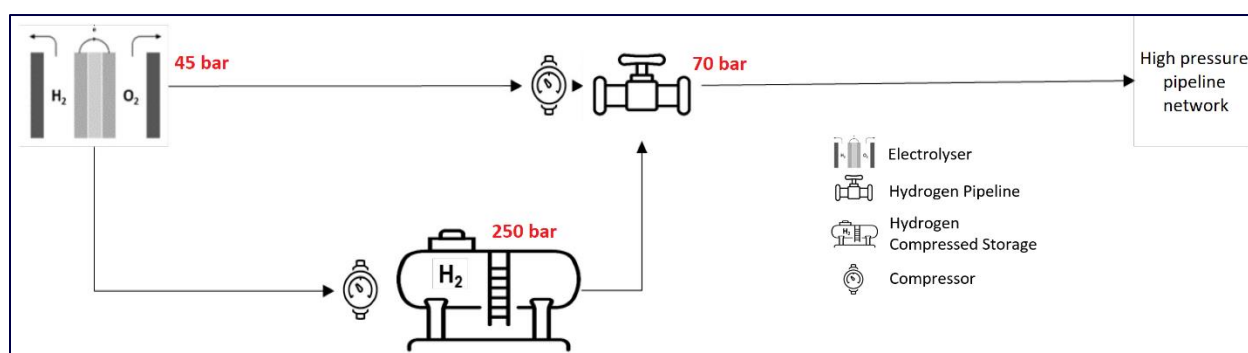
| Parameter name                           | Value  | Unit                     |
|--|--------|--------------------------|
| Design lifetime                          | 20     | Years                    |
| CAPEX                                    | 1265   | €/kW                     |
| OPEX                                     | 1.875  | %/CAPEX                  |
| Stack lifetime (replacement)             | 60000  | hours                    |
| Stack replacement cost                   | 414000 | €/MW                     |
| CO <sub>2</sub> content (Grey emissions) | 1570   | kg CO <sub>2</sub> eq/MW |

**Table 49: PEM electrolyser parameters used in CEC study**

### 6.2.9.2 Compressor

Without major facility or workforce adaptations, companies already active in this sector are able to manufacture compressors (including new high-speed centrifugal compressors) for new hydrogen pipelines and for injecting the gas into underground storage facilities. The materials needed to manufacture them are easily obtained and unlikely to be affected by major bottlenecks. For capacities of up to 2 GW, current state-of-the-art piston compressors are the most economical solution, with several companies manufacturing them around the world [75].

As shown in Figure 63, the CEC prerequisite is the production of hydrogen with a pressure of 45 bars and its subsequent compression to 70 bars, which is a suitable pressure for high-pressure gas pipelines. A hydrogen tank is used for hydrogen storage (H<sub>2</sub> compressed at 250 bars) see chapter 6.2.10.



**Figure 63: Schematic diagram of hydrogen production and storage**

| Parameter name                           | Value                      |                          | Unit                     |
|--|----------------------------|--------------------------|--------------------------|
|  | Medium pressure compressor | High pressure compressor |                          |
| Electric power                           | 0.0978 – 3.12              | 0.352 – 11.2             | MW                       |
| Inlet pressure                           | 45                         |                          | bar                      |
| Outlet pressure                          | 70                         | 250                      | bar                      |
| Compression rate                         | 1.55                       | 5.55                     | -                        |
| Motor efficiency                         | 0.9                        |                          | -                        |
| Isentropic efficiency                    | 0.7                        |                          | -                        |
| Design lifetime                          | 20                         |                          | Years                    |
| CAPEX                                    | 1000                       |                          | €/kW                     |
| OPEX                                     | 1                          |                          | %/CAPEX                  |
| CO <sub>2</sub> content (Grey emissions) | Neglected                  |                          | kg CO <sub>2</sub> eq/MW |

**Table 50: Medium and High pressure compressor parameters used in CEC study**

### 6.2.10 Hydrogen storage

Storage of hydrogen as a gas typically requires high-pressure tanks (250 bars).

| Parameter name                           | Value                              | Unit                     |
|--|------------------------------------|--------------------------|
| Maximum hydrogen flowrate                | According to H <sub>2</sub> demand | Kg/h                     |
| Maximum H <sub>2</sub> storage size      | 160000                             | kg                       |
| Operating pressure                       | 250                                | bar                      |
| Design lifetime                          | 20                                 | Years                    |
| CAPEX                                    | 490                                | €/kg                     |
| OPEX                                     | 1.5                                | %/CAPEX                  |
| CO <sub>2</sub> content (Grey emissions) | Neglected                          | kg CO <sub>2</sub> eq/MW |

**Table 51: H<sub>2</sub> storage parameters used in CEC study**

### 6.2.11 Thermal energy storage

The CEC study assessed underground Thermal Energy Storage (TES) applicability as seasonal storage for domestic heating. Underground thermal storage is suitable for the considered cases that focus on the region with extensive coal mining. Therefore, the undermined area filled with

water can be used as the primary heat storage medium. Excess heat produced during the summer is stored by pumping heat into undermined area at large depths (several hundred meters).

The choice of this sensible heat storage is also suitable for the following reasons:

- Long term storage - large energy capacity, which is required for seasonal storage purpose,
- Inexpensive media,
- Low storage output temperature, which is required by district heating networks,
- Zero emissions produced during operation.

| Parameter name             | Value        | Unit                      |
|----------------------------|--------------|---------------------------|
| Energy capacity            | Up to 3900   | MWh                       |
| Storage output temperature | <150         | °C                        |
| Round trip efficiency      | 50 - 90      | %                         |
| Speed of ramp time         | Several days | -                         |
| Grey CO <sub>2</sub>       | Neglected    | kg CO <sub>2</sub> eq/MWh |
| Design lifetime            | 20           | Years                     |
| Heat loss                  | 0.01         | MWh/h                     |
| Self-discharge             | 2            | %/day                     |
| Maxim charge and discharge | Up to 3.25   | MW                        |
| CAPEX                      | 16760        | €/MWh                     |
| OPEX                       | 1            | %/CAPEX                   |

**Table 52: Underground thermal energy storage parameters used in CEC study [64]**

### 6.2.12 Electrical energy storage

Inherently intermittent character of large amount of renewable electric sources (RES) implemented in CECs is compensated, to some extent, by Electrical Energy Storage (EES). According to deliverable 1.2 [64], one of the preferred EES, is Lithium-ion Battery Energy Storage (BES), which is capable of discharge times in minutes/several hours, with correspondingly high sizes that reach several dozen megawatts, up to 100 MW. Therefore, main purposes of BES are peak shaving, ensuring the stability of network and provision of more continuous electricity supply.

| Parameter name                  | Value     | Unit                     |
|---------------------------------|-----------|--------------------------|
| Energy capacity                 | Up to 200 | MWh                      |
| Power rating                    | 0-100     | MW                       |
| Discharge Efficiency            | 85        | %                        |
| Annual energy capacity          | 63000     | MWh                      |
| Number of cycles                | 315       | -                        |
| Battery degradation (per annum) | 2.6       | %                        |
| Grey CO <sub>2</sub>            | Neglected | kg CO <sub>2</sub> eq/MW |
| Design lifetime                 | 15        | Years                    |
| CAPEX                           | 877.15    | €/MW                     |
| OPEX                            | 4.4       | %/CAPEX                  |

**Table 53: Lithium-ion battery storage parameters used in CEC study [64]**

### 6.2.13 District heating networks

Only one DHN was assessed in the CEC by interconnecting the DHN of Bohumin/Orlova cities, the DHN of Havirov/Karvina cities and the DHN of Trinec. The values of annual heat supply within modelled area are summarized in Table 54.

| District heating network | Annual heat supply [GJ] | Annual heat supply [MWh] | Possible heat supply/demand by interconnection of DHNs [MWh] |
|--------------------------|-------------------------|--------------------------|--|
| Karvina/Havirov          | 2 446 093               | 279 234                  | 542 560  |
| Bohumin/Orlova           | 556 566                 | 63 535                   |  |
| Trinec                   | 1 750 165               | 199 791                  |  |

**Table 54: Potential heat supply to interconnected DHN**

Heat consumption in district heating to household and tertiary sector varies seasonally and monthly. The diagram of heat demand (consumption) by month during the year used for all scenarios of the CEC is presented in the Figure 64. Heat losses relevant to the site are assumed of 20% and no CAPEX/OPEX is considered for the heat transportation pipe. But for the LCOH calculation total heat production without heat losses was calculated.

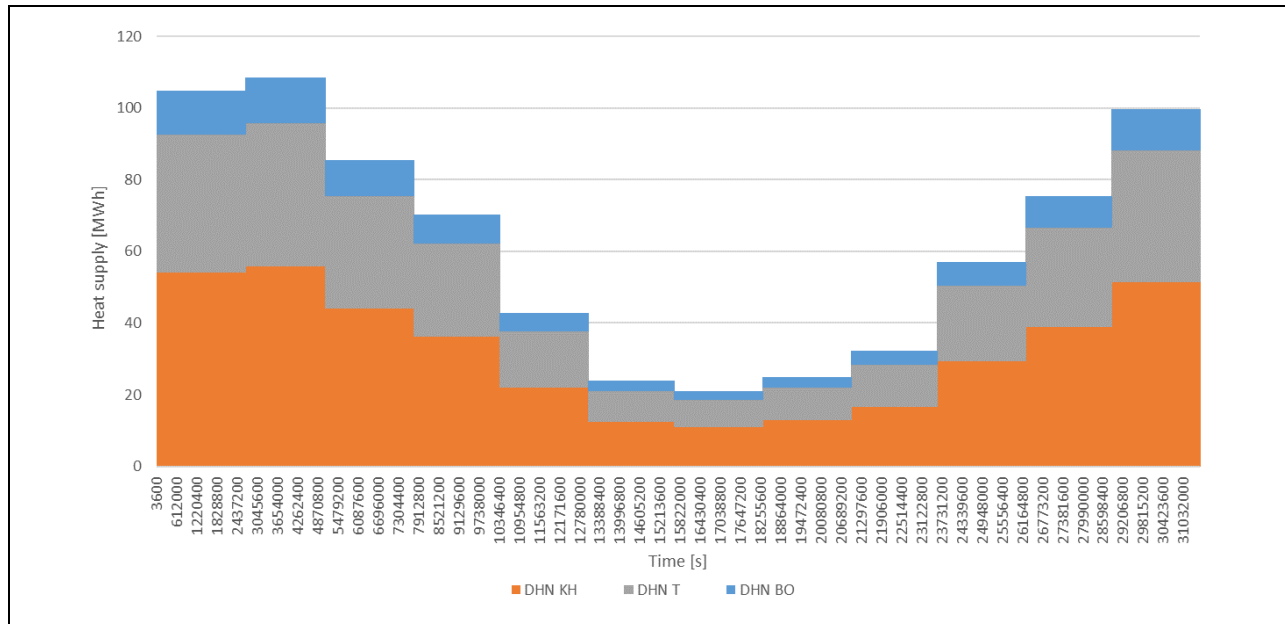


Figure 64: DHN heat demand diagram

In addition, the potential for maximum continued heat supply to industry was examined in each scenario. An example for industrial heat supply at the level of 125 MWh is shown in Figure 65. The use of low-potential heat for industry is limited, therefore, the utilization of this heat is speculative. This evaluation was only done for an economic comparison of how higher heat supply would affect the heat price. The possibility of cooling supply was not considered in this study.

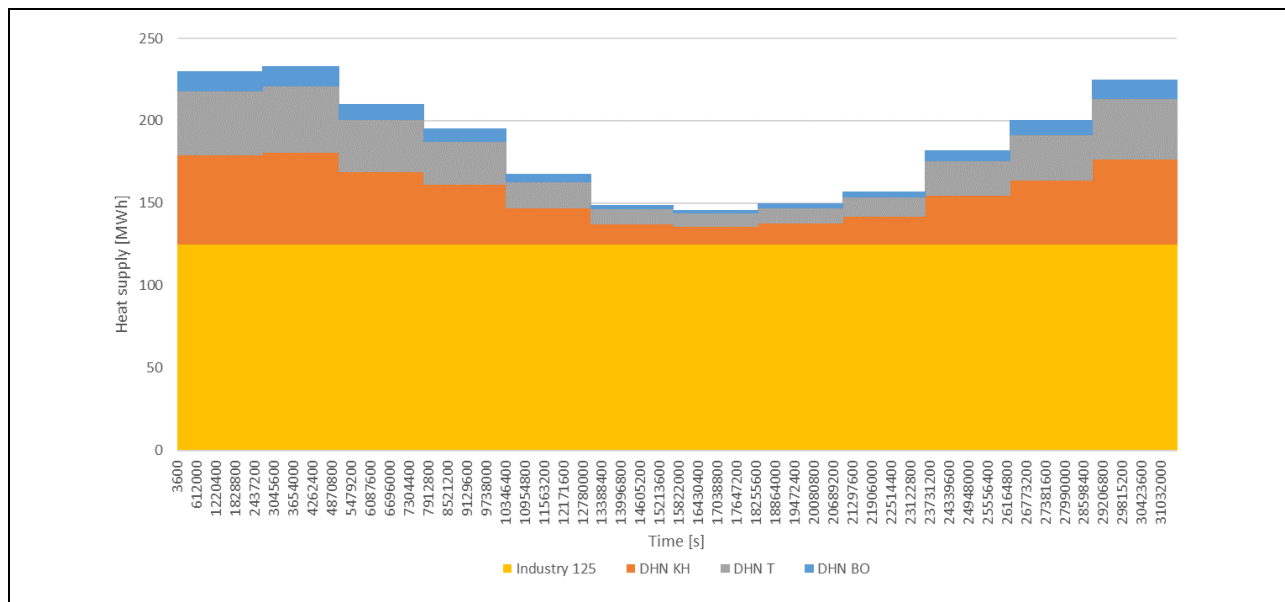
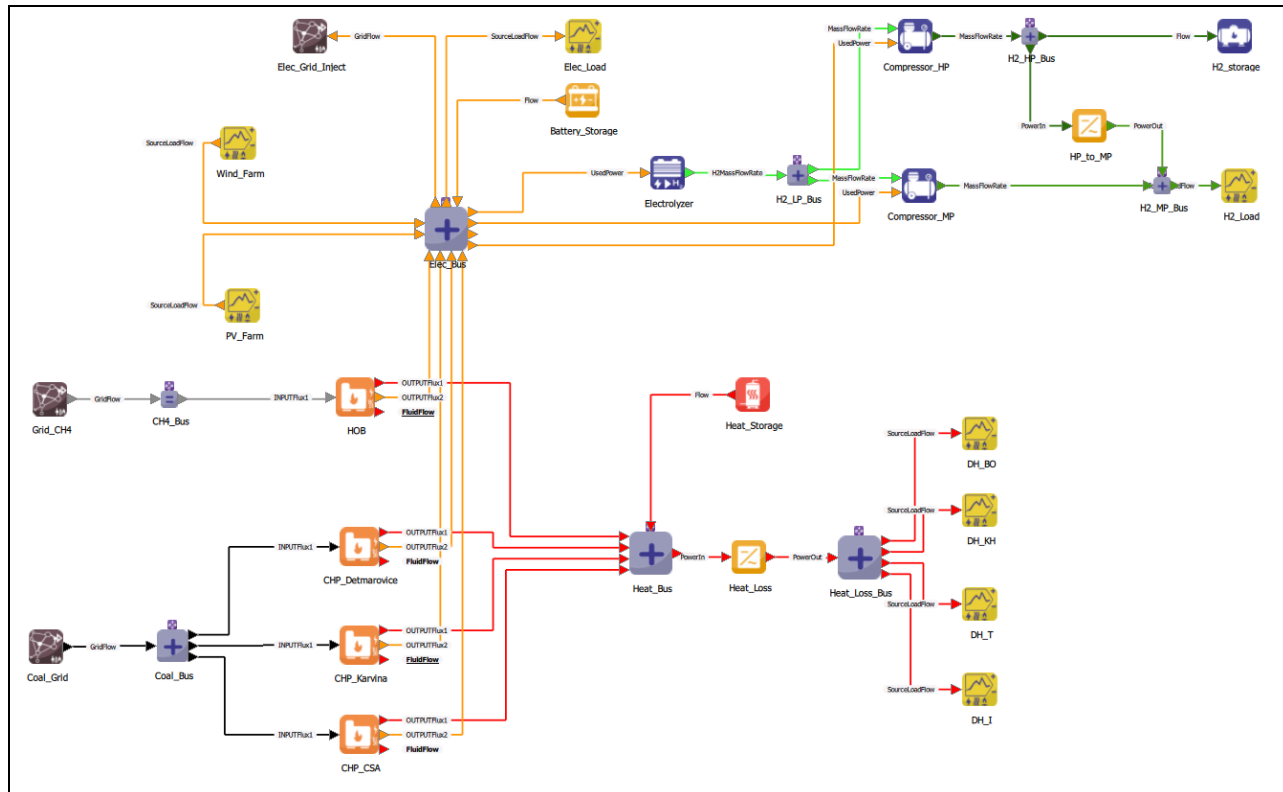


Figure 65: DHN heat demand diagram with potential heat supply to industry (125 MWh)

### 6.3 District Heating with Low SMR deployment Scenario in 2035

The scenario for District Heating with Scenario 2035 (L35) corresponds to a scenario, where all current coal sources are replaced by new ones with similar performance parameters. This scenario represents a case where no SMR unit has been built by 2035 and the demand for heat, electricity and hydrogen is supplied by fossil fuel sources and renewables. The purpose of this “reference” scenario corresponding to “business-as-usual” is to provide results for comparison with other more decarbonisation scenarios.

The architecture modelled in PERSEE for the L35 configuration is shown in Figure 66.



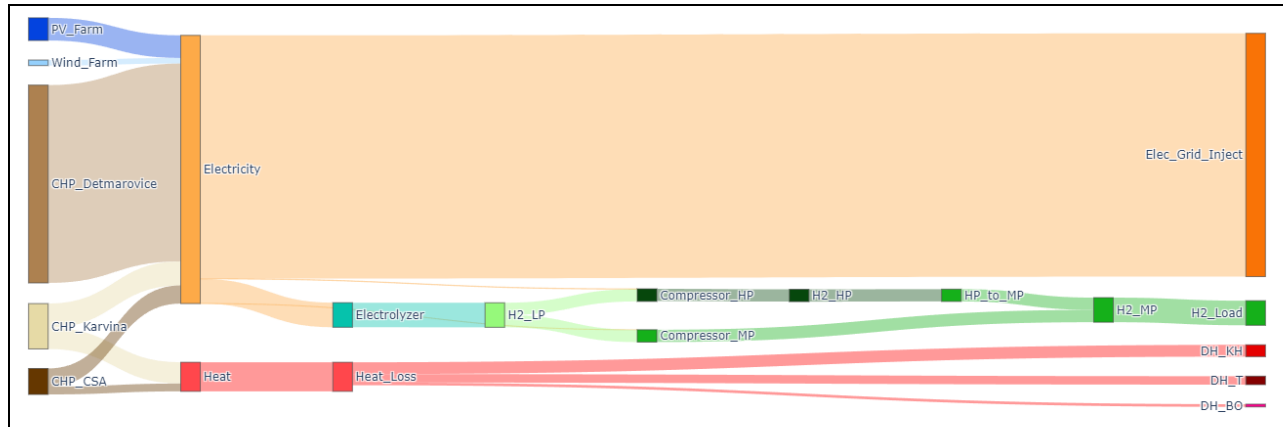
**Figure 66: Low SMR deployment Scenario 2035 - architecture for PERSEE modelling**

For this architecture, five runs were computed for different hydrogen demand for 2035 (H20 – H100 variants) according to Table 48. In addition, several iterative calculations were performed to determine the maximum possible continuous supply for the industry. The variant with this hypothetical increased heat supply was also evaluated using PERSEE (“Heat” variant). The results of component power sizing and their electricity, heat and hydrogen yearly production for each L35 variant are summarised in the Table 55. Finally, energy fluxes in the form of a Sankey diagram for the maximal hydrogen demand (H100) are shown in the Figure 67.

| Component              | Variable  | Variant    |          |          |          |          |          |
|------------------------|---|------------|----------|----------|----------|----------|----------|
|                        |   | H20        | H40      | H60      | H80      | H100     | Heat     |
| CHP Detmarovice        | Thermal/electrical power [MW <sub>th</sub> /MW <sub>e</sub> ] | 1555 / 600 |          |          |          |          |          |
|                        | Annual electricity production [MWh <sub>e</sub> ]             | 5.20E+06   |          |          |          |          | 5.11E+06 |
|                        | Annual heat production [MWh <sub>th</sub> ]                   | 0          |          |          |          |          | 9.49E+04 |
| CHP Karvina            | Thermal/electrical power [MW <sub>th</sub> /MW <sub>e</sub> ] | 248 / 87   |          |          |          |          |          |
|                        | Annual electricity production [MWh <sub>e</sub> ]             | 6.33E+05   |          |          |          |          | 5.27E+05 |
|                        | Annual heat production [MWh <sub>th</sub> ]                   | 5.58E+05   |          |          |          |          | 1.02E+06 |
| CHP CSA                | Thermal/electrical power [MW <sub>th</sub> /MW <sub>e</sub> ] | 171 / 60   |          |          |          |          |          |
|                        | Annual electricity production [MWh <sub>e</sub> ]             | 4.77E+05   |          |          |          |          | 3.82E+05 |
|                        | Annual heat production [MWh <sub>th</sub> ]                   | 2.07E+05   |          |          |          |          | 6.23E+05 |
| PV farm                | Peak power [MW <sub>e</sub> ]                                 | 415        |          |          |          |          |          |
|                        | Annual electricity production [MWh <sub>e</sub> ]             | 5.94E+05   |          |          |          |          |          |
| Wind farm              | Peak power [MW <sub>e</sub> ]                                 | 42.2       |          |          |          |          |          |
|                        | Annual electricity production [MWh <sub>e</sub> ]             | 1.46E+05   |          |          |          |          |          |
| HOB                    | Thermal power [MWh]   | 0          |          |          |          |          |          |
|                        | Annual heat production [MWh <sub>th</sub> ]                   | 0          |          |          |          |          |          |
| Compressor HP          | Installed size [kW <sub>e</sub> ]                             | 352        | 703      | 1055     | 1406     | 1759     | 352      |
|                        | Annual electricity consumption [MWh <sub>e</sub> ]            | 1.54E+03   | 3.08E+03 | 4.62E+03 | 6.15E+03 | 7.69E+03 | 1.54E+03 |
| Compressor MP          | Installed size [kW <sub>e</sub> ]                             | 97.8       | 195      | 293      | 391      | 480      | 97.8     |
|                        | Annual electricity consumption [MWh <sub>e</sub> ]            | 4.28E+02   | 8.56E+02 | 1.28E+03 | 1.71E+03 | 2.14E+03 | 4.28E+02 |
| Electrolyser           | Installed size [MW <sub>e</sub> ]                             | 14.8       | 29.5     | 44.3     | 59.0     | 73.8     | 14.8     |
|                        | Annual electricity consumption [MWh <sub>e</sub> ]            | 1.29E+05   | 2.58E+05 | 3.87E+05 | 5.17E+05 | 6.46E+05 | 1.29E+05 |
|                        | Annual hydrogen production [kg]                               | 2.44E+06   | 4.87E+06 | 7.31E+06 | 9.74E+06 | 1.22E+07 | 2.44E+06 |
| H <sub>2</sub> storage | Max. storage capacity [kg]                                    | 3337       | 6674     | 10011    | 13348    | 16685    | 3337     |
| Battery storage        | Energy capacity [MWh <sub>e</sub> ]                           | 0          |          |          |          |          |          |
| Thermal storage        | Max. storage thermal capacity [MWh <sub>th</sub> ]            | 0          |          |          |          |          |          |

Table 55: L35 – component sizing and component production



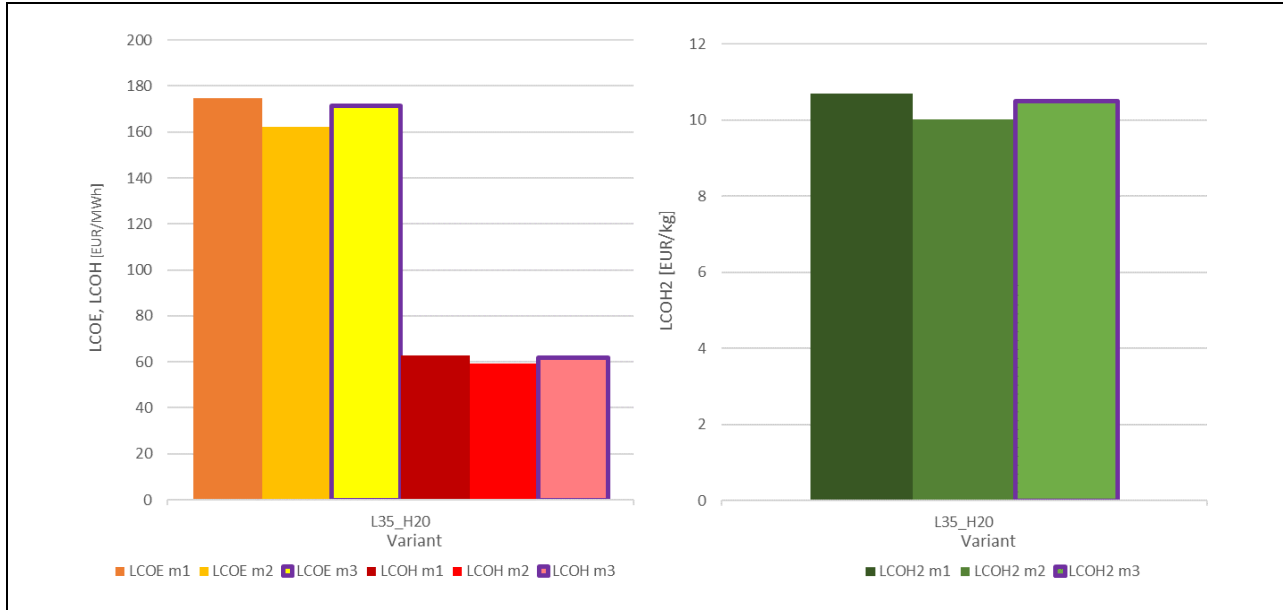


**Figure 67: Sankey graph of L35 for maximum H2 demand**

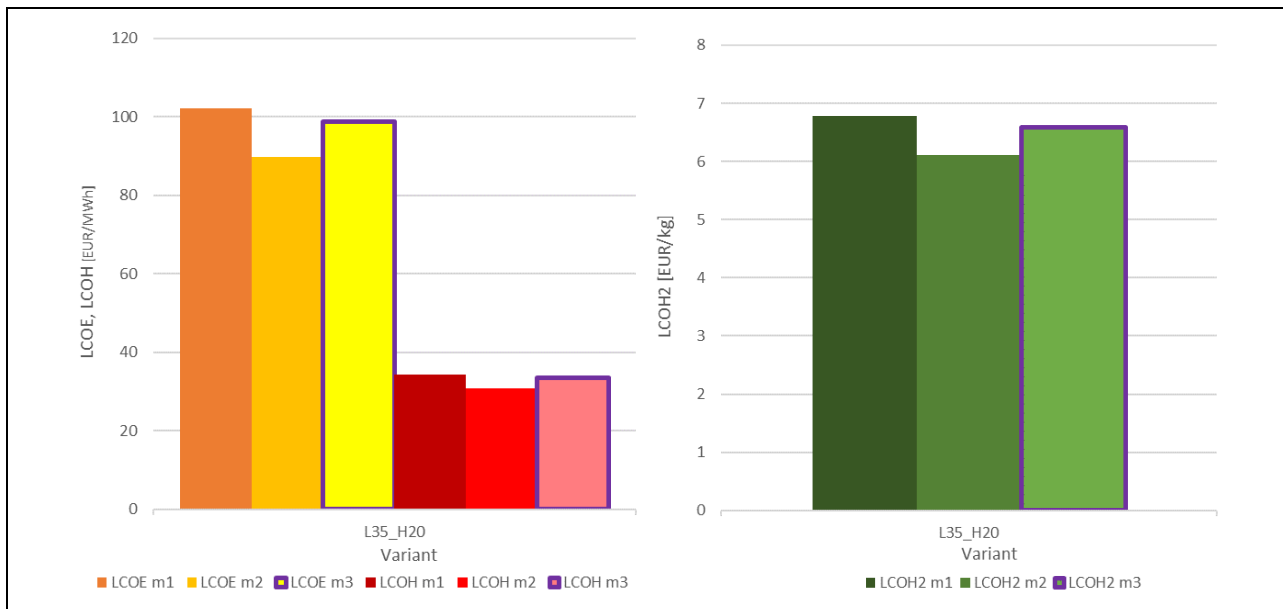
The demand for hydrogen production was met in studied variants. In the case of fulfilment of 100 % hydrogen demand (H100 variant), almost 10% of the total amount of electricity produced was consumed by electrolyser and compressors. In addition to saturating the demand for heat to the DHNs, the HES configured in L35 is potentially able to supply heat to the industry up to  $8.32E+05$  MWh<sub>th</sub> (see Table 56) and thus increase the supply of heat 1.5 times compared to the DHN supply. HOB, battery and thermal storage was not used in L35 HES configuration.

For all scenarios, the economic evaluation “**Energy allocation**” was carried out as described in chapter 4.1 and for all three approaches m1, m2 and m3. “Energy allocation” method with consideration of the CO<sub>2</sub> emission allowance (considered average price of emission allowance for the year 2023 of the value of 83.5 €/t CO<sub>2</sub>) is presented in Figure 68. Specifically, for L35 scenario, an additional evaluation was carried out without considering emission allowances in order to assess their impact on the overall economic efficiency of the system (Figure 69).

Note: The **results obtained from m3 method are considered final**, therefore they are highlighted in purple for all scenarios.

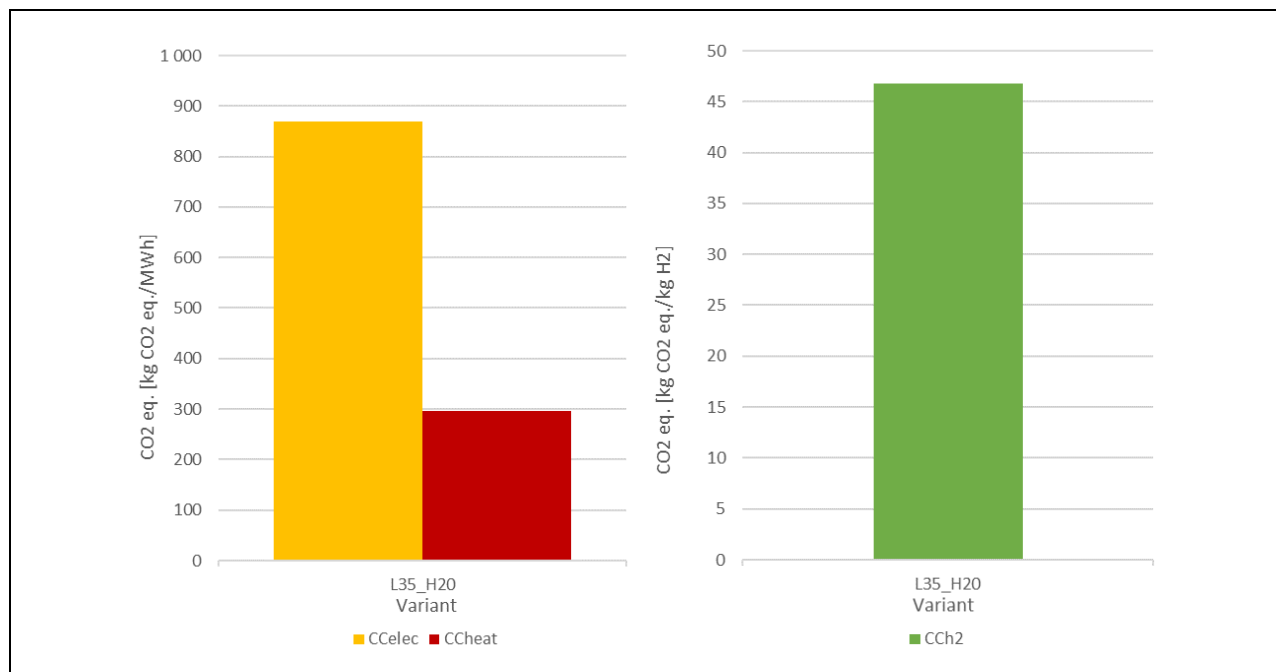


**Figure 68: Scenario L35 - Energy allocation approach for evaluation of LCOE, LCOH and LCOH<sub>2</sub> with CO<sub>2</sub> emission allowances**



**Figure 69: Scenario L35 - Energy allocation approach for evaluation of LCOE, LCOH and LCOH<sub>2</sub> without CO<sub>2</sub> emission allowances**

Environmental impact assessment of L35 was done according to the approach presented in chapter 4.2. The Figure 70 shows the yearly CO<sub>2</sub> emissions of the whole system. L35 scenario based on fossil fuel sources reaches very high carbon intensity of electricity, heat and hydrogen. The EU Taxonomy threshold for sustainable hydrogen manufacturing is almost 16 times larger in this HES.



**Figure 70: Scenario L35 – CO<sub>2</sub> intensity evaluation**

As discussed in chapter 4.1, the most relevant results are given by the “Energy allocation” approach with m3 method. These results are presented as final economic evaluation.

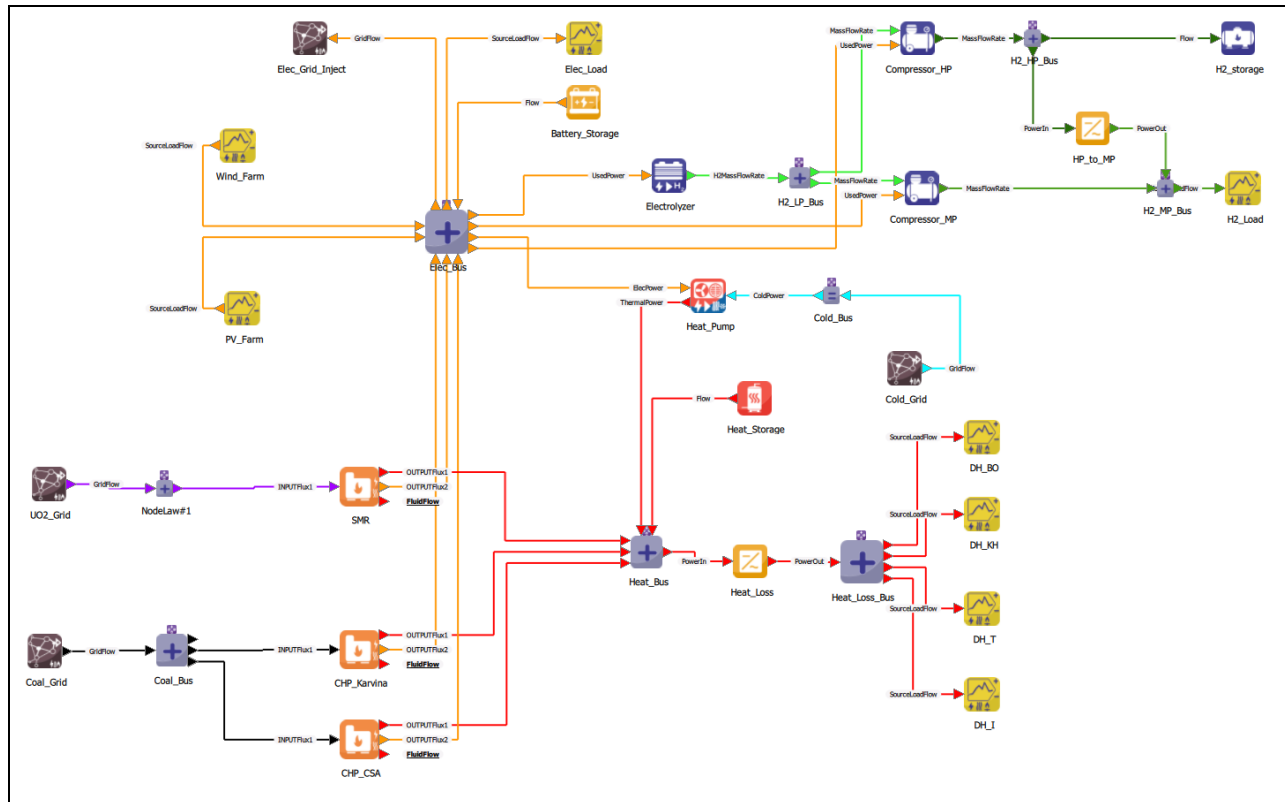
A summary of the most important results of the L35 scenario is presented in Table 56.

| Variable   | H20   | H40      | H60      | H80      | H100     |
|--|---|----------|----------|----------|----------|
| Electricity supply to grid [MWh <sub>e</sub> /year]                  | 6.92E+06  | 6.79E+06 | 6.66E+06 | 6.53E+06 | 6.40E+06 |
| Heat supply to DHN [MWh <sub>th</sub> /year]                         | 5.43E+05 (Potential heat for industry 8.32E+05) |          |          |          |          |
| Hydrogen supply [kg/year]  | 2.44E+06  | 4.87E+06 | 7.31E+06 | 9.74E+06 | 1.22E+07 |
| LCOE with EA [€/MWh <sub>e</sub> ]                                   | <b>171</b>                                      |          |          |          |          |
| LCOH with EA [€/MWh <sub>th</sub> ]                                  | <b>62.0</b>                                     |          |          |          |          |
| LCOH <sub>2</sub> with EA [€/kg H <sub>2</sub> ]                     | <b>10.5</b>                                     |          |          |          |          |
| LCOE without EA [€/MWh <sub>e</sub> ]                                | 98.8  |          |          |          |          |
| LCOH without EA [€/MWh <sub>th</sub> ]                               | 33.5  |          |          |          |          |
| LCOH <sub>2</sub> without EA [€/kg H <sub>2</sub> ]                  | 6.59  |          |          |          |          |
| CI <sub>elec</sub> [kg CO <sub>2</sub> /MWh]                         | <b>869</b>                                      |          |          |          |          |
| CI <sub>heat</sub> [kg CO <sub>2</sub> /MWh]                         | <b>296</b>                                      |          |          |          |          |
| CI <sub>H<sub>2</sub></sub> [kg CO <sub>2</sub> /kg H <sub>2</sub> ] | <b>46.8</b>                                     |          |          |          |          |

**Table 56: L35 – key results**

#### 6.4 District Heating with High SMR deployment Scenario in 2035 – 1 SMR

District Heating with High SMR deployment Scenario in 2035 – 1 SMR (H35-1SMR) includes a single SMR unit replacing the whole Detmarovice power plant, Karvina and CSA heating plants are replaced by new coal power units with similar performance parameter. This scenario reflects a situation where there is a strong reduction in coal mining and the construction of only one SMR unit is achieved. As a result, equivalent power replacement of the studied system is not achieved, and the electricity production is decreased in comparison with L35 scenario. Heat demand for interconnected DHNs is fully satisfied by one SMR unit. Architecture of H35-1SMR is shown in Figure 71.



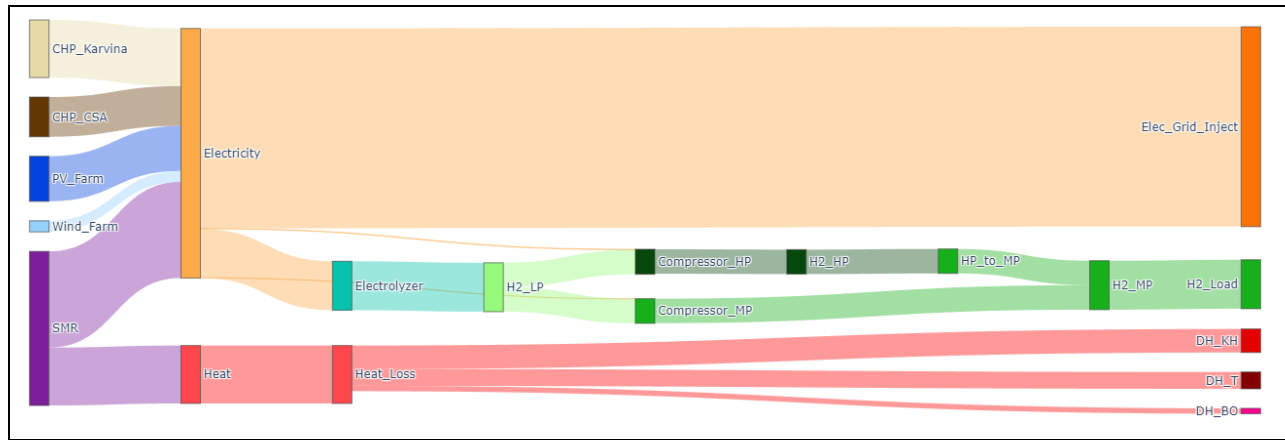
**Figure 71: High SMR deployment Scenario 2035 – 1 SMR - architecture for PERSEE modelling**

Similarly, to the L35, five runs for different hydrogen demands (H20 – H100 variants in 2035) and one run for potentially increased heat supply (“Heat” variant) were computed by using PERSEE. The results of component power sizing and their electricity, heat and hydrogen production for each H35-1SMR variant are summarised in the Table 57. Finally, energy fluxes in the form of a Sankey diagram for the maximum hydrogen demand (H100) are shown in the Figure 72.

| Component              | Variable                                     | Variant   |          |          |          |          |          |
|------------------------|--|-----------|----------|----------|----------|----------|----------|
|                        |  | H20       | H40      | H60      | H80      | H100     | Heat     |
| CHP Karvina            | Thermal/electrical power [ $MW_{th}/MW_e$ ]  | 248 / 87  |          |          |          |          |          |
|                        | Annual electricity production [ $MWh_e$ ]    | 7.60E+05  |          |          |          |          | 5.69E+05 |
|                        | Annual heat production [ $MWh_{th}$ ]        | 0         |          |          |          |          | 8.37E+05 |
| CHP CSA                | Thermal/electrical power [ $MW_{th}/MW_e$ ]  | 171 / 60  |          |          |          |          |          |
|                        | Annual electricity production [ $MWh_e$ ]    | 5.24E+05  |          |          |          |          | 4.17E+05 |
|                        | Annual heat production [ $MWh_{th}$ ]        | 0         |          |          |          |          | 4.68E+05 |
| SMR                    | Thermal/electrical power [ $MW_{th}/MW_e$ ]  | 540 / 162 |          |          |          |          |          |
|                        | Annual electricity production [ $MWh_e$ ]    | 1.27E+06  |          |          |          |          | 9.37E+05 |
|                        | Annual heat production [ $MWh_{th}$ ]        | 7.65E+05  |          |          |          |          | 2.46E+06 |
| PV farm                | Peak power [ $MW_e$ ]                        | 415       |          |          |          |          |          |
|                        | Annual electricity production [ $MWh_e$ ]    | 5.94E+05  |          |          |          |          |          |
| Wind farm              | Peak power [ $MW_e$ ]                        | 42.2      |          |          |          |          |          |
|                        | Annual electricity production [ $MWh_e$ ]    | 1.46E+05  |          |          |          |          |          |
| Heat Pump              | Thermal power [ $MWh$ ]                      | 0         |          |          |          |          |          |
|                        | Annual heat production [ $MWh_{th}$ ]        | 0         |          |          |          |          |          |
| Compressor HP          | Installed size [ $kW_e$ ]                    | 352       | 703      | 1055     | 1406     | 1759     | 352      |
|                        | Annual electricity consumption [ $MWh_e$ ]   | 1.54E+03  | 3.08E+03 | 4.62E+03 | 6.15E+03 | 7.69E+03 | 1.54E+03 |
| Compressor MP          | Installed size [ $kW_e$ ]                    | 97.8      | 195      | 293      | 391      | 480      | 97.8     |
|                        | Annual electricity consumption [ $MWh_e$ ]   | 4.28E+02  | 8.56E+02 | 1.28E+03 | 1.71E+03 | 2.14E+03 | 4.28E+02 |
| Electrolyser           | Installed size [ $MW_e$ ]                    | 14.8      | 29.5     | 44.3     | 59.0     | 73.8     | 14.8     |
|                        | Annual electricity consumption [ $MWh_e$ ]   | 1.29E+05  | 2.58E+05 | 3.87E+05 | 5.17E+05 | 6.46E+05 | 1.29E+05 |
|                        | Annual hydrogen production [kg]              | 2.44E+06  | 4.87E+06 | 7.31E+06 | 9.74E+06 | 1.22E+07 | 2.44E+06 |
| H <sub>2</sub> storage | Max. storage capacity [kg]                   | 3337      | 6674     | 10011    | 13348    | 16685    | 3337     |
| Battery storage        | Energy capacity [ $MWh_e$ ]                  | 0         |          |          |          |          |          |
| Thermal storage        | Max. storage thermal capacity [ $MWh_{th}$ ] | 0         |          |          |          |          |          |

Table 57: H35-1SMR – component sizing and component production

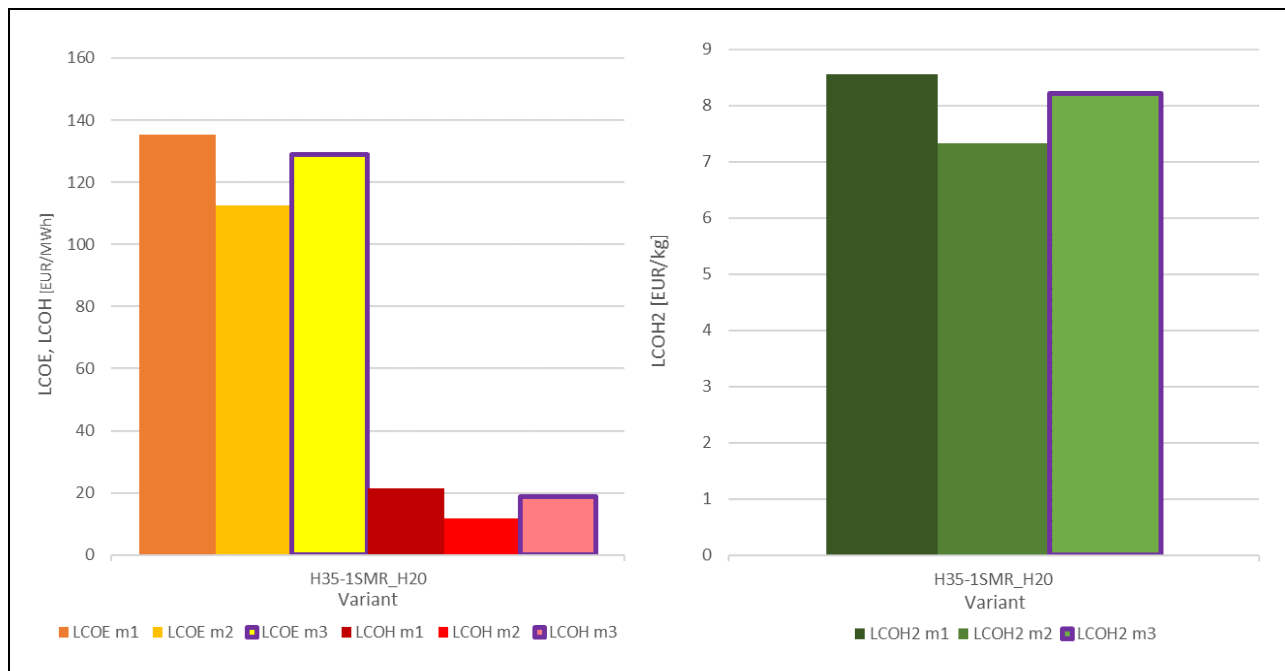




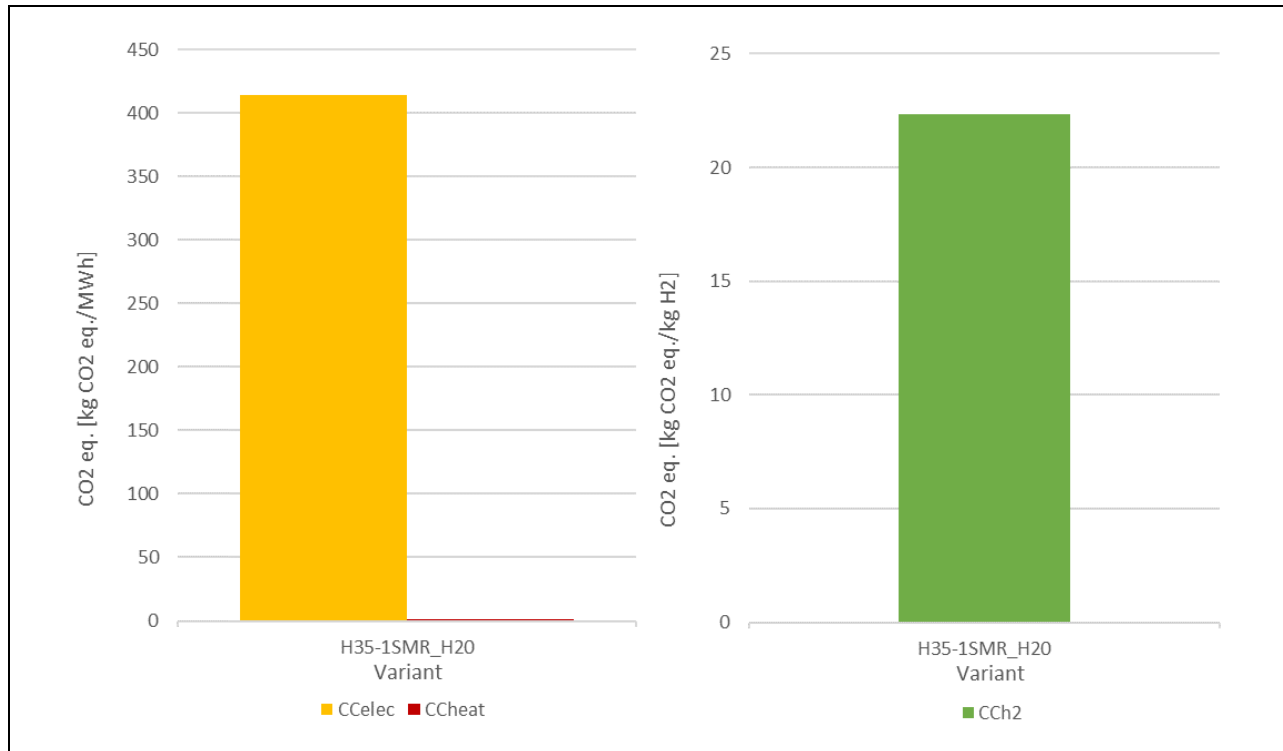
**Figure 72: Sankey graph of H35-1SMR for maximum H2 demand**

In the case of maximum hydrogen demand (H100 variant), almost 20 % of the total amount of electricity produced was consumed by electrolyser and compressors. The H35-1SMR HES is potentially able to supply heat to the industry up to 2.41E+06 MWh<sub>th</sub> (see Table 58) and thus increase the supply of heat approximately 4.5 times compared to the DHN supply. Heat pump, battery and thermal storage was not used in H35-1SMR HES configuration.

Evaluation of LCOE, LCOH and LCOH<sub>2</sub> for H35-1SMR scenario is in Figure 73, CO<sub>2</sub> content evaluation is shown in Figure 74. Key results of this scenario are summarized in Table 58.



**Figure 73: Scenario H35-1SMR - Energy allocation approach for evaluation of LCOE, LCOH and LCOH<sub>2</sub>**

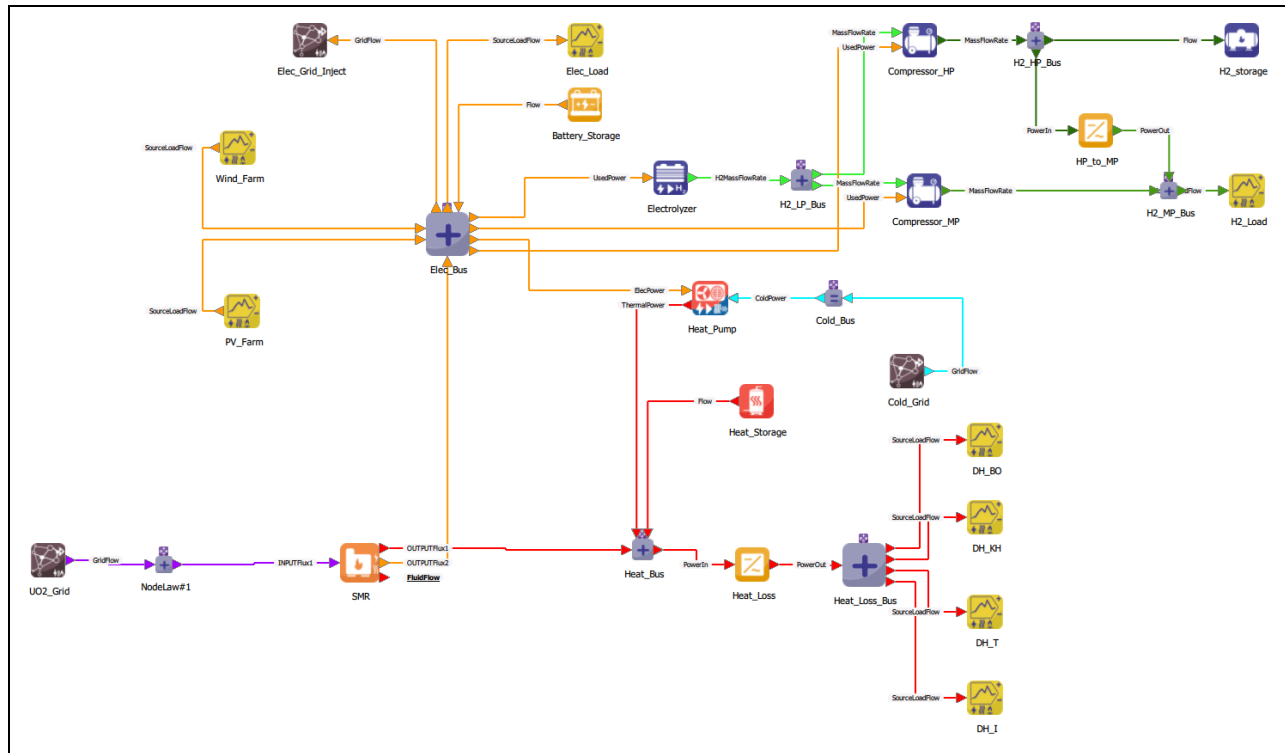
Figure 74: Scenario H35-1SMR – CO<sub>2</sub> intensity evaluation

| Variable   | H20   | H40      | H60      | H80      | H100     |
|--|---|----------|----------|----------|----------|
| Electricity supply to grid [MWh <sub>e</sub> /year]                  | 3.16E+06  | 3.03E+06 | 2.90E+06 | 2.77E+06 | 2.64E+06 |
| Heat supply to DHN [MWh <sub>th</sub> /year]                         | 5.43E+05 (potential heat for industry 2.41E+06) |          |          |          |          |
| Hydrogen supply [kg/year]  | 2.44E+06  | 4.87E+06 | 7.31E+06 | 9.74E+06 | 1.22E+07 |
| LCOE with EA [€/MWh <sub>e</sub> ]                                   | 129   |          |          |          |          |
| LCOH with EA [€/MWh <sub>th</sub> ]                                  | 18.8  |          |          |          |          |
| LCOH <sub>2</sub> with EA [€/kg H <sub>2</sub> ]                     | 8.22  |          |          |          |          |
| CI <sub>elec</sub> [kg CO <sub>2</sub> /MWh]                         | 415   |          |          |          |          |
| CI <sub>heat</sub> [kg CO <sub>2</sub> /MWh]                         | 1.02  |          |          |          |          |
| CI <sub>H<sub>2</sub></sub> [kg CO <sub>2</sub> /kg H <sub>2</sub> ] | 22.3  |          |          |          |          |

Table 58: H35-1SMR – key results

### 6.5 District Heating - High SMR deployment Scenario in 2035 – 2 SMRs

For District Heating with High SMR deployment Scenario 2035 – 2 SMRs (H35-2SMR), all coal combustion sources are replaced by two SMR units in Detmarovice site. This scenario reflects the requirement to end coal mining by 2035. Analysed architecture by PERSEE software is depicted in Figure 75.



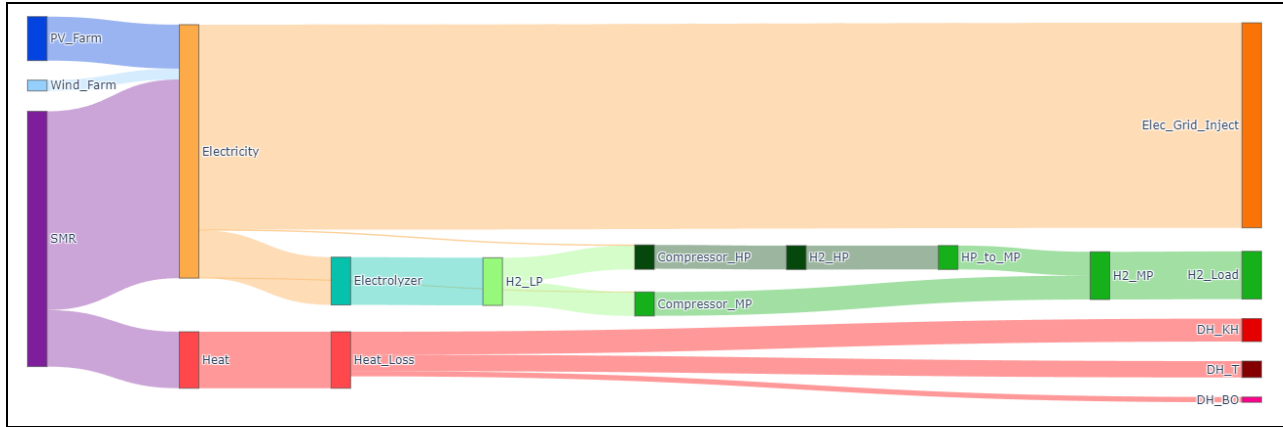
**Figure 75: High SMR deployment Scenario in 2035 – 2SMRs - architecture for PERSEE modelling**

Five runs for different hydrogen demands (H20 – H100 variants of 2035) and one run for potentially increased heat supply (heat variant) were computed by using PERSEE. The results of component power sizing and their electricity, heat, and hydrogen production for each H35-2SMR variant are summarised in the Table 57. Energy fluxes in the form of a Sankey diagram for the maximal hydrogen demand (H100 variant) are shown in the Figure 76.

| Component              | Variable                                     | Variant    |          |          |          |          |          |
|------------------------|--|------------|----------|----------|----------|----------|----------|
|                        |  | H20        | H40      | H60      | H80      | H100     | Heat     |
| SMR                    | Thermal/electrical power [ $MW_{th}/MW_e$ ]  | 1080 / 324 |          |          |          |          |          |
|                        | Annual electricity production [ $MWh_e$ ]    | 2.69E+06   |          |          |          |          | 1.93E+06 |
|                        | Annual heat production [ $MWh_{th}$ ]        | 7.65E+05   |          |          |          |          | 4.62E+06 |
| PV farm                | Peak power [ $MW_e$ ]                        | 415        |          |          |          |          |          |
|                        | Annual electricity production [ $MWh_e$ ]    | 5.94E+05   |          |          |          |          |          |
| Wind farm              | Peak power [ $MW_e$ ]                        | 42.2       |          |          |          |          |          |
|                        | Annual electricity production [ $MWh_e$ ]    | 1.46E+05   |          |          |          |          |          |
| Heat Pump              | Thermal power [ $MWh$ ]                      | 0          |          |          |          |          |          |
|                        | Annual heat production [ $MWh_{th}$ ]        | 0          |          |          |          |          |          |
| Compressor HP          | Installed size [ $kW_e$ ]                    | 352        | 703      | 1055     | 1406     | 1759     | 352      |
|                        | Annual electricity consumption [ $MWh_e$ ]   | 1.54E+03   | 3.08E+03 | 4.62E+03 | 6.15E+03 | 7.69E+03 | 1.54E+03 |
| Compressor MP          | Installed size [ $kW_e$ ]                    | 97.8       | 195      | 293      | 391      | 480      | 97.8     |
|                        | Annual electricity consumption [ $MWh_e$ ]   | 4.28E+02   | 8.56E+02 | 1.28E+03 | 1.71E+03 | 2.14E+03 | 4.28E+02 |
| Electrolyser           | Installed size [ $MW_e$ ]                    | 14.8       | 29.5     | 44.3     | 59.0     | 73.8     | 14.8     |
|                        | Annual electricity consumption [ $MWh_e$ ]   | 1.29E+05   | 2.58E+05 | 3.87E+05 | 5.17E+05 | 6.46E+05 | 1.29E+05 |
|                        | Annual hydrogen production [kg]              | 2.44E+06   | 4.87E+06 | 7.31E+06 | 9.74E+06 | 1.22E+07 | 2.44E+06 |
| H <sub>2</sub> storage | Max. storage capacity [kg]                   | 3337       | 6674     | 10011    | 13348    | 16685    | 3337     |
| Battery storage        | Energy capacity [ $MWh_e$ ]                  | 0          |          |          |          |          |          |
| Thermal storage        | Max. storage thermal capacity [ $MWh_{th}$ ] | 0          |          |          |          |          |          |

Table 59: H35-2SMR – component sizing and component production

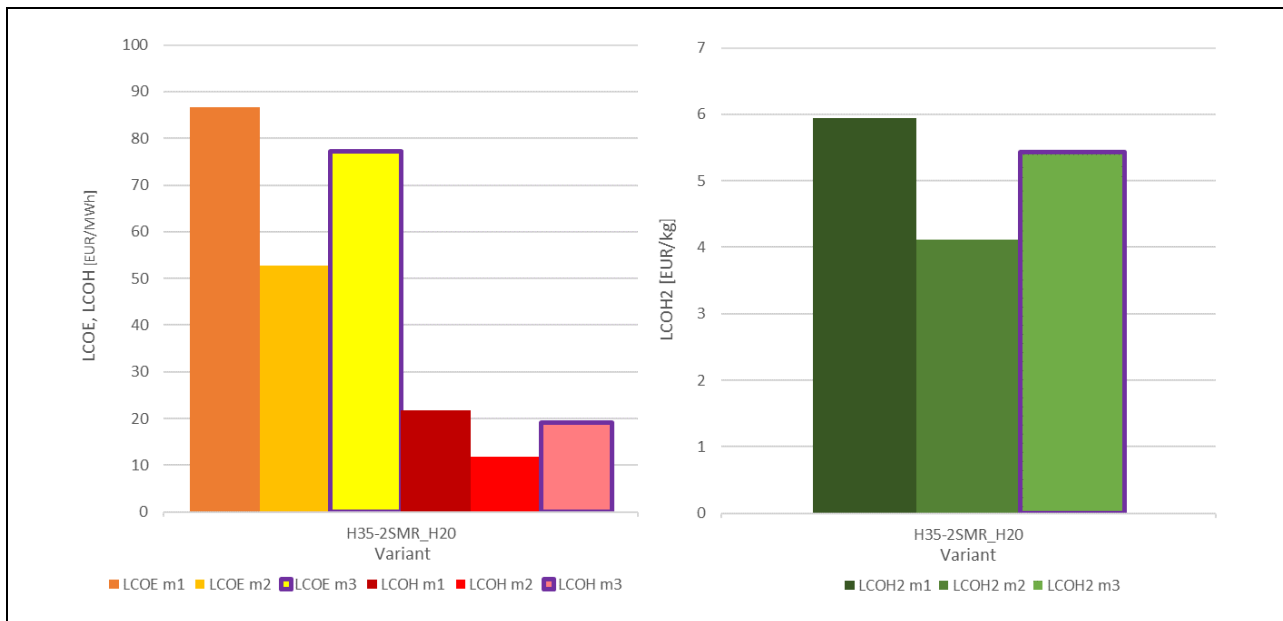




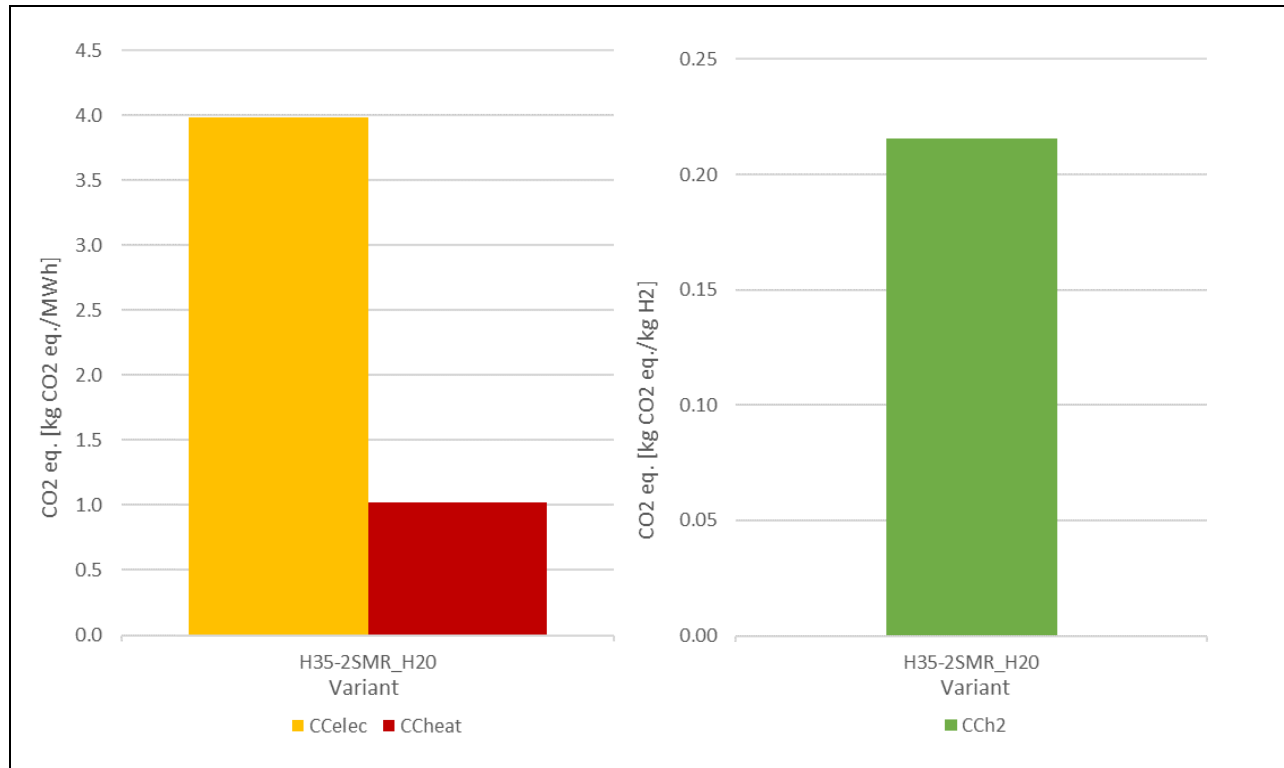
**Figure 76: Sankey graph of H35-2SMR for maximum H2 demand**

In the case of maximum hydrogen demand (H100 variant), almost 24 % of the total amount of electricity produced was consumed by electrolyser and compressors. The H35-2SMR HES is potentially able to supply heat to the industry up to  $3.15E+06$  MWh<sub>th</sub> (see Table 60) and thus increase the supply of heat 5.8 times compared to the DHN supply. Heat pump, battery and thermal storage was not used in the H35-2SMR HES configuration.

Evaluation of LCOE, LCOH and LCOH<sub>2</sub> for H35-2SMR scenario is in Figure 77, CO<sub>2</sub> emission evaluation is shown in Figure 78. The EU Taxonomy threshold for sustainable hydrogen manufacturing is achieved in this decarbonisation scenario. Key results of this scenario are summarized in Table 60.



**Figure 77: Scenario H35-2SMR - Energy allocation approach for evaluation of LCOE, LCOH and LCOH<sub>2</sub>**

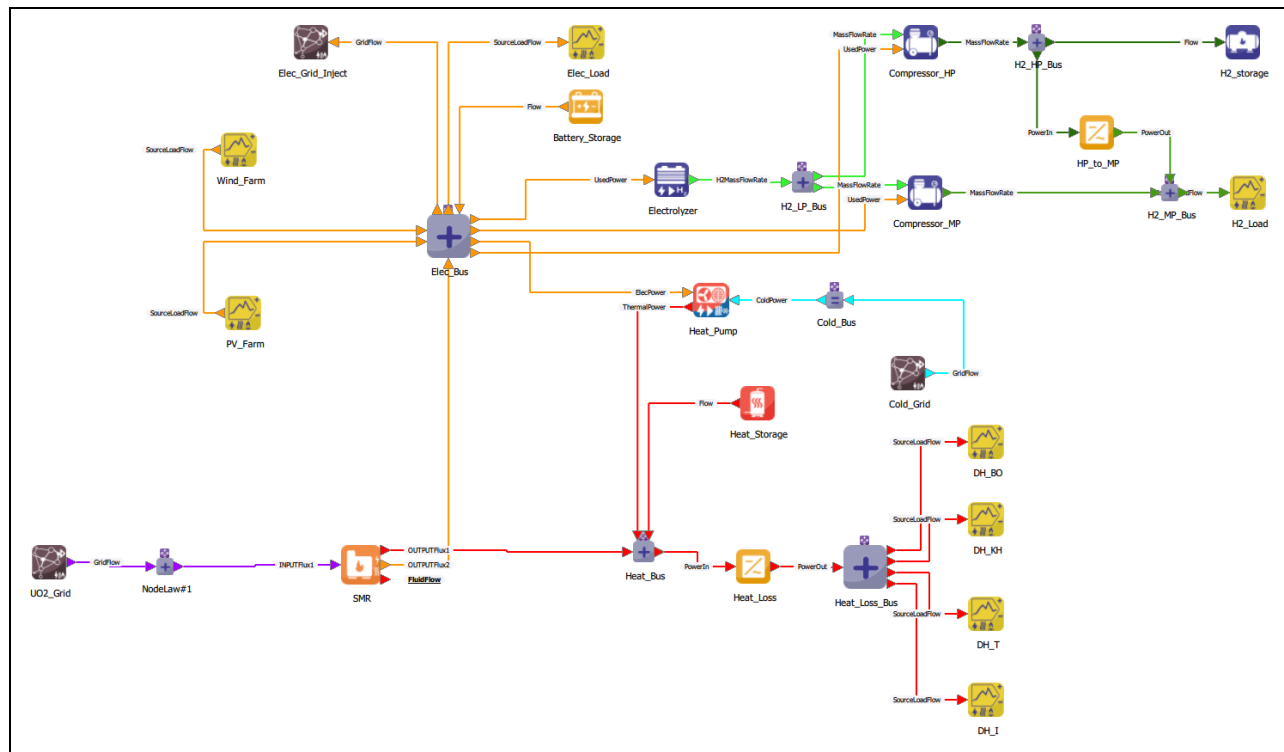
Figure 78: Scenario H35-2SMR – CO<sub>2</sub> intensity evaluation

| Variable   | H20   | H40      | H60      | H80      | H100     |
|--|---|----------|----------|----------|----------|
| Electricity supply to grid [MWh <sub>e</sub> /year]                  | 3.30E+06  | 3.17E+06 | 3.04E+06 | 2.90E+06 | 2.77E+06 |
| Heat supply to DHN [MWh <sub>th</sub> /year]                         | 5.43E+05 (Potential heat for industry 3.15E+06) |          |          |          |          |
| Hydrogen supply [kg/year]  | 2.44E+06  | 4.87E+06 | 7.31E+06 | 9.74E+06 | 1.22E+07 |
| LCOE [€/MWh <sub>e</sub> ]   | <b>77.3</b>                                     |          |          |          |          |
| LCOH [€/MWh <sub>th</sub> ]  | <b>19.0</b>                                     |          |          |          |          |
| LCOH <sub>2</sub> [€/kg H <sub>2</sub> ]                             | <b>5.43</b>                                     |          |          |          |          |
| CI <sub>elec</sub> [kg CO <sub>2</sub> /MWh]                         | <b>3.99</b>                                     |          |          |          |          |
| CI <sub>heat</sub> [kg CO <sub>2</sub> /MWh]                         | <b>1.02</b>                                     |          |          |          |          |
| CI <sub>H<sub>2</sub></sub> [kg CO <sub>2</sub> /kg H <sub>2</sub> ] | <b>0.215</b>                                    |          |          |          |          |

Table 60: H35-2SMR – key results

## 6.6 District Heating with High SMR deployment Scenario in 2050

For District Heating with High SMR deployment Scenario in 2050 (H50-4SMR), four SMR units are deployed in Detmarovice site to meet requirements for long term full decarbonisation and higher hydrogen production in the CR. Based on the Czech hydrogen strategy, the H50-4SMR scenario considers significantly higher requirements for hydrogen production (6.3 times higher than for 2035). The amount of hydrogen produced for particular variants is shown in the Table 47. This scenario demonstrates that combining intermittent renewable energy sources, SMRs operation in base load and hydrogen production can create a very efficient and stable energy system. Analysed architecture by PERSEE software is depicted in Figure 79.



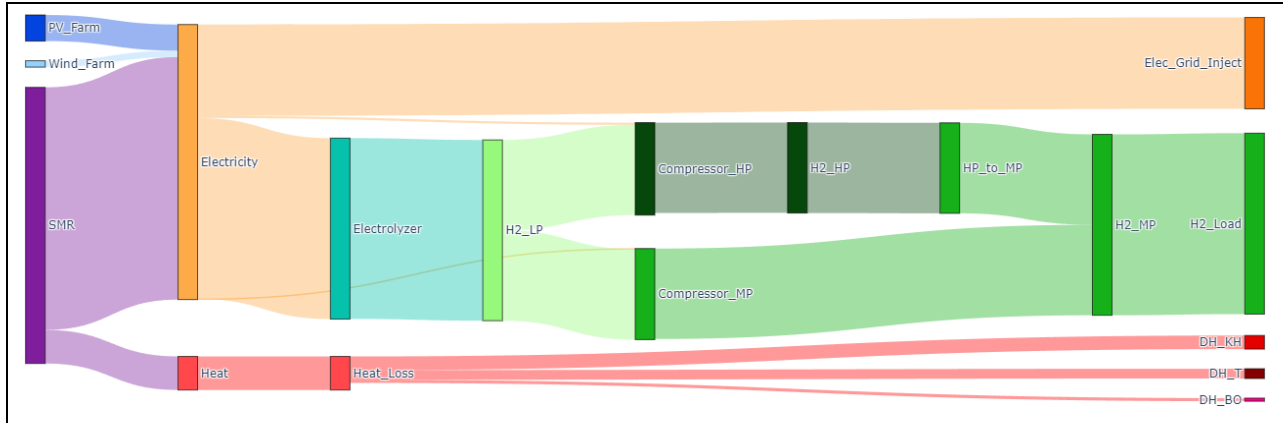
**Figure 79: High Scenario 2055 architecture for PERSEE modelling**

Five runs for different hydrogen demand (H20 – H100 variants of 2050) and one run for potentially increased heat supply (“Heat” variant) were computed by PERSEE tool. The results of component power sizing and their electricity, heat, and hydrogen production for each H50-4SMR variant are summarised in the Table 61. Energy fluxes in the form of a Sankey diagram for the maximal hydrogen demand (H100 variant) are shown in the Figure 80.

| Component              | Variable                                     | Variant    |          |          |          |          |          |
|------------------------|--|------------|----------|----------|----------|----------|----------|
|                        |  | H20        | H40      | H60      | H80      | H100     | Heat     |
| SMR                    | Thermal/electrical power [ $MW_{th}/MW_e$ ]  | 2160 / 648 |          |          |          |          |          |
|                        | Annual electricity production [ $MWh_e$ ]    | 5.53E+06   |          |          |          |          | 3.80E+06 |
|                        | Annual heat production [ $MWh_{th}$ ]        | 7.65E+05   |          |          |          |          | 9.54E+06 |
| PV farm                | Peak power [ $MW_e$ ]                        | 415        |          |          |          |          |          |
|                        | Annual electricity production [ $MWh_e$ ]    | 5.94E+05   |          |          |          |          |          |
| Wind farm              | Peak power [ $MW_e$ ]                        | 42.2       |          |          |          |          |          |
|                        | Annual electricity production [ $MWh_e$ ]    | 1.46E+05   |          |          |          |          |          |
| Heat Pump              | Thermal power [MWh]                          | 0          |          |          |          |          |          |
|                        | Annual heat production [ $MWh_{th}$ ]        | 0          |          |          |          |          |          |
| Compressor HP          | Installed size [ $kW_e$ ]                    | 2246       | 4491     | 6737     | 8982     | 11228    | 2246     |
|                        | Annual electricity consumption [ $MWh_e$ ]   | 9.82E+03   | 1.96E+04 | 2.95E+04 | 3.93E+04 | 4.91E+04 | 9.82E+03 |
| Compressor MP          | Installed size [ $kW_e$ ]                    | 624        | 1248     | 1872     | 2496     | 3120     | 624      |
|                        | Annual electricity consumption [ $MWh_e$ ]   | 2.73E+03   | 5.47E+03 | 8.20E+03 | 1.09E+04 | 1.37E+04 | 2.73E+03 |
| Electrolyser           | Installed size [ $MW_e$ ]                    | 94.2       | 188      | 283      | 377      | 471      | 94.2     |
|                        | Annual electricity consumption [ $MWh_e$ ]   | 8.25E+05   | 1.65E+06 | 2.47E+06 | 3.30E+06 | 4.12E+06 | 8.25E+05 |
|                        | Annual hydrogen production [kg]              | 1.56E+07   | 3.11E+07 | 4.67E+07 | 6.22E+07 | 7.78E+07 | 1.56E+07 |
| H <sub>2</sub> storage | Max. storage capacity [kg]                   | 21304      | 42608    | 63912    | 85216    | 106520   | 21304    |
| Battery storage        | Energy capacity [ $MWh_e$ ]                  | 0          |          |          |          |          |          |
| Thermal storage        | Max. storage thermal capacity [ $MWh_{th}$ ] | 0          |          |          |          |          |          |

Table 61: H50-4SMR – component sizing and component production

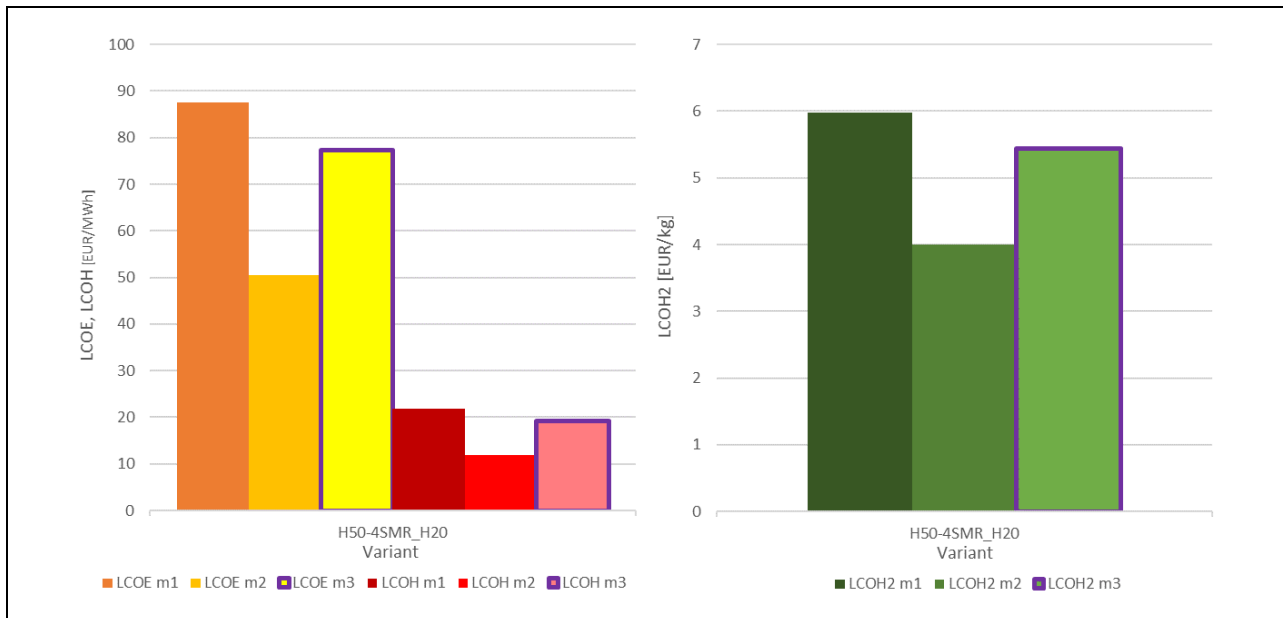




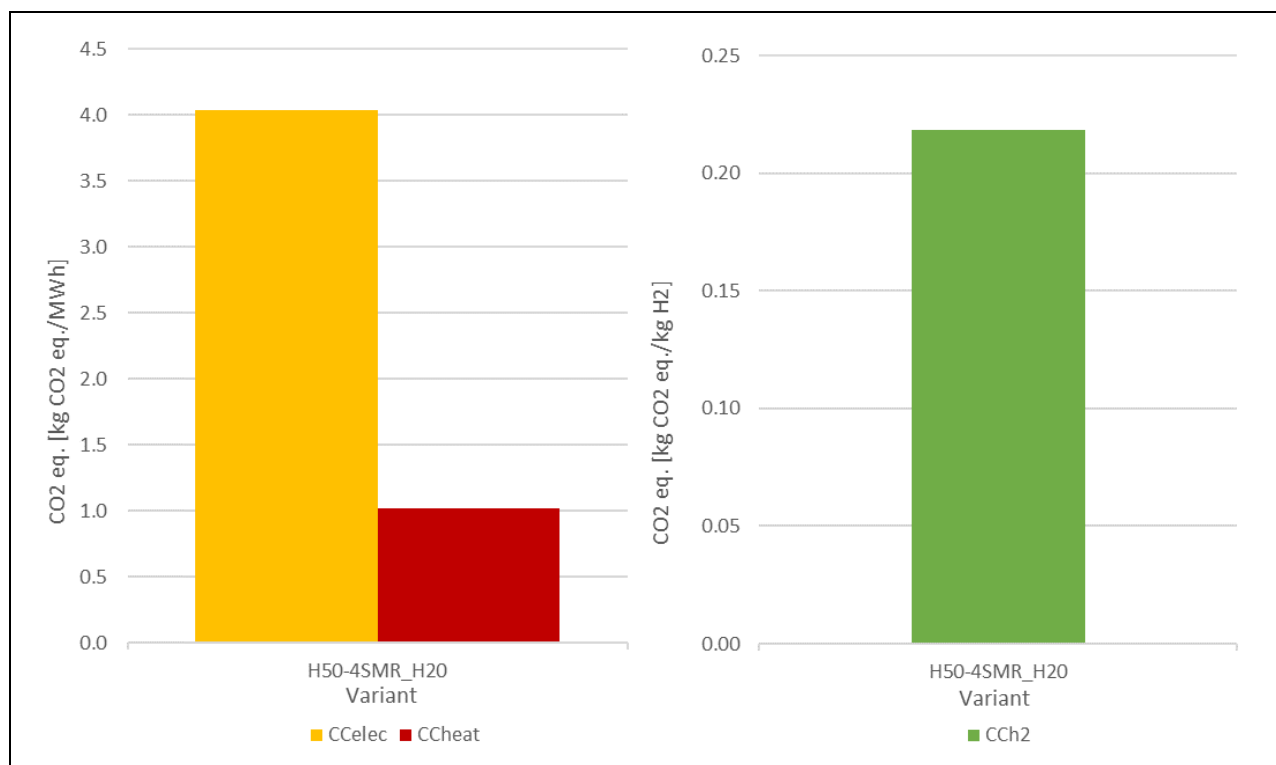
**Figure 80: Sankey graph of H50-4SMR for maximum H2 demand**

In the case of maximum hydrogen demand (H100 variant), almost 67 % of the total amount of electricity produced was consumed by electrolyser and compressors. The H50-4SMR HES is potentially able to supply heat to the industry up to  $7.10E+06$  MWh<sub>th</sub> (see Table 62) and thus increase the supply of heat 13 times compared to the DHN supply. Heat pump, battery and thermal storage was not used in H50-4SMR HES configuration.

Evaluation of LCOE, LCOH and LCOH<sub>2</sub> for H50-4SMR scenario is in Figure 81, CO<sub>2</sub> intensity evaluation is shown in Figure 82. The EU Taxonomy threshold for sustainable hydrogen manufacturing is achieved in this decarbonisation scenario. Key results of this scenario are summarized in Table 62.



**Figure 81: Scenario H50-4SMR - Energy allocation approach for evaluation of LCOE, LCOH and LCOH<sub>2</sub> with CO<sub>2</sub> emission allowance**



**Figure 82: Scenario H50-4SMR – CO<sub>2</sub> intensity evaluation**

| Variable   | H20   | H40      | H60      | H80      | H100     |
|--|---|----------|----------|----------|----------|
| Electricity supply to grid [MWh <sub>e</sub> ]                       | 5.43E+06  | 4.59E+06 | 3.76E+06 | 2.92E+06 | 2.08E+06 |
| Heat supply to DHN [MWh <sub>th</sub> ]                              | 5.43E+05 (potential heat for industry 7.10E+06) |          |          |          |          |
| Hydrogen supply [kg]   | 1.56E+07  | 3.11E+07 | 4.67E+07 | 6.22E+07 | 7.78E+07 |
| LCOE [€/MWh <sub>e</sub> ]   | 77.3  |          |          |          |          |
| LCOH [€/MWh <sub>th</sub> ]  | 19.2  |          |          |          |          |
| LCOH <sub>2</sub> [€/kg H <sub>2</sub> ]                             | 5.44  |          |          |          |          |
| CI <sub>elec</sub> [kg CO <sub>2</sub> /MWh]                         | 4.04  |          |          |          |          |
| CI <sub>heat</sub> [kg CO <sub>2</sub> /MWh]                         | 1.02  |          |          |          |          |
| CI <sub>H<sub>2</sub></sub> [kg CO <sub>2</sub> /kg H <sub>2</sub> ] | 0.218   |          |          |          |          |

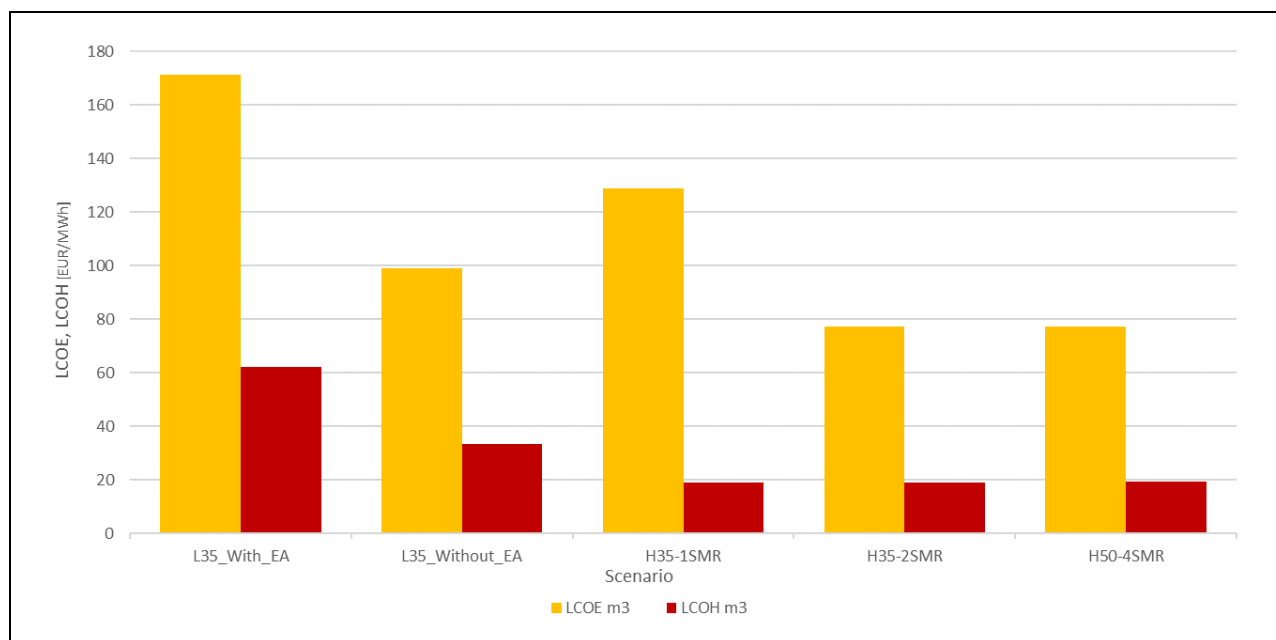
**Table 62: H50-4SMR – key results**

## 6.7 Comparison of studied scenarios and conclusion

The Central European case study is focused on an industrialized territory (steel and heavy machinery industry) of the Moravian-Silesian Region of the Czech Republic, with crucial need of an environment decarbonisation. The challenge here is on the one hand to find viable

alternatives to replace existing coal heat sources and reduce polluting emissions and on the other hand to assess a potential of hydrogen production for industrial application (e.g. decarbonisation of a steel production) and establishment of “Hydrogen valley” in the selected territory of the MSR. The CEC study results thus contribute to defining the path for meeting the decarbonisation goal the EC 2040 Climate Target Communication for the Czech Republic.

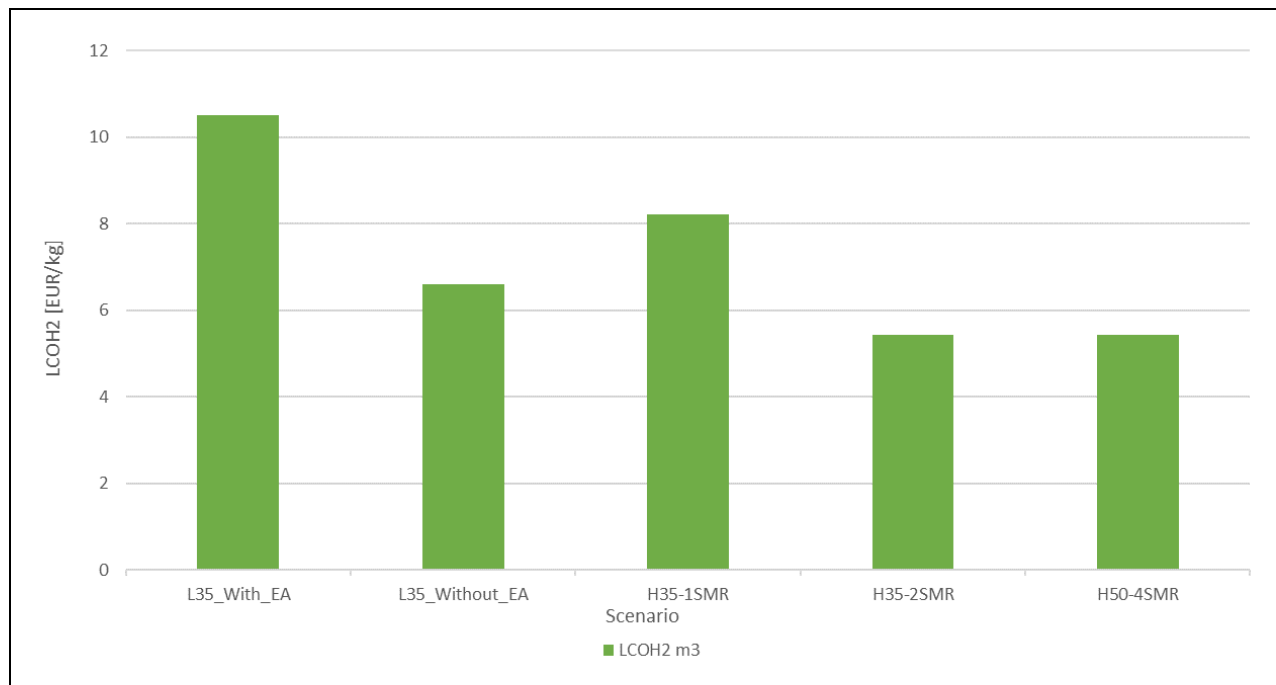
Therefore, the CEC deals with an assessment of a techno-economic and environmental profitability of a possible replacement of fossil power and heat sources by the SMR technology and a possibility of producing H<sub>2</sub> using a low temperature electrolysis in the industrialized area of the Moravian-Silesian region. Altogether, four scenarios were evaluated in CEC study. In the “reference” scenario, coal sources were replaced by new ones in order to provide results for comparison with more decarbonisation scenarios. Furthermore, scenarios with one and two implemented SMR units were studied, in which equivalent power replacement is not achieved compared to the reference scenario. This is achieved in a scenario with four SMR units implemented. More detailed information on individual scenarios is provided in chapters 6.3, 6.4, 6.5 and 6.6.



**Figure 83: Comparison of studied scenarios - Proportional CAPEX and OPEX approach for evaluation of LCOE and LCOH**

The economic results of individual scenarios are summarized and compared in the Figure 83 and Figure 84. The graphs show that it is not possible to achieve an economic return for the “reference” scenario under the current conditions as the price of produced commodities significantly exceeds the market price. For the “reference” scenario, a calculation was also

performed without considering the effect of emission allowances, which shows their significant impact on the resulting price of electricity and heat. **For the decarbonisation scenarios the LCOE values are 77.3 €/MWh<sub>e</sub> respective LCOH<sub>2</sub> 5.44 €/kg H<sub>2</sub>.**

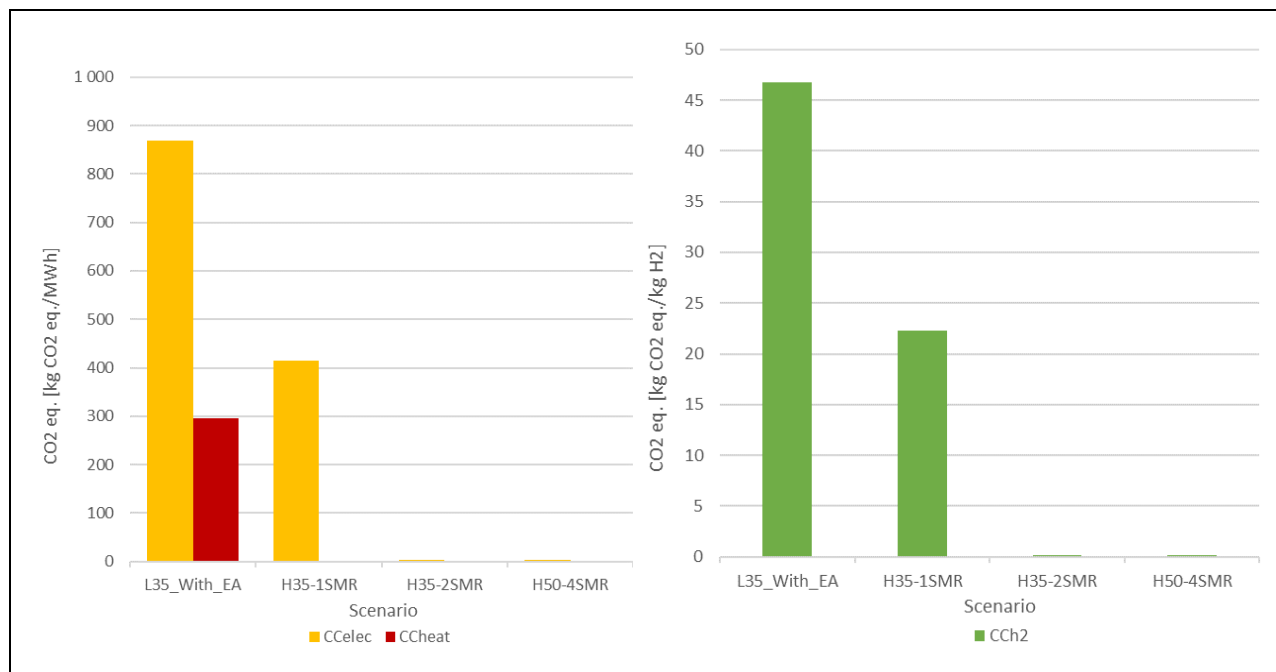


**Figure 84: Comparison of studied scenarios - Proportional CAPEX and OPEX approach for evaluation of LCOH<sub>2</sub>**

The results of environmental impact assessment for individual scenarios are presented in the Figure 85. It is evident from these results that the gradual replacement of coal-fired sources by SMRs leads to a strong reduction in the total emissions produced. For example, for the scenarios using CHPs, the EU Taxonomy threshold for sustainable hydrogen manufacturing is almost 16 respectively 8 times larger. On the contrary, for decarbonisation scenarios using SMRs, the required threshold for sustainable hydrogen is reached with a large margin.

CEC has shown the potential to decarbonize electricity, heat and H<sub>2</sub> productions by using SMRs, renewables and low temperature electrolysis. The combination of these sources in HES offers a carbon free and cost-effective solution.

Results of the CEC can be easily utilized as for the territory of Silesian Voivodeship in Poland, which is similar industrial region as the Moravian-Silesian Region, as for Žilina self-governing region in the Slovak Republic.



**Figure 85: Comparison of studied scenarios – CI\_elec, CI\_heat and CI\_H2 evaluation**

Given the level of uncertainty of the inputs used, it is important to verify the dependence of the economic results on changes in important input parameters. It is proposed to perform sensitivity analyses for changes in the following input data:

- Specific investment and variable costs of SMR,
- Specific investment and variable costs of CHP,
- Specific investment costs of photovoltaic power plants (they contribute a relatively large amount of electricity power in studied scenarios),
- Fuel costs (coal, UO<sub>2</sub>),
- Different hydrogen and heat loads.

## 7 Conclusion

In conclusion, this report has provided a detailed analysis of techno-economic and environmental profitability of the three case studies studied within the TANDEM project. It illustrates the implementation of an optimization process based on the minimization of an objective function, related to environmental impact or costs, by finding an optimal sizing of hybrid energy system components; it enables to assess demonstrative case studies.

These case studies focused on exploring the potential of NHES for two kinds of architectures in three distinct European regions: District heating in Northern European and in Central European and Energy Hub in Southern European. This study also shows different point of views: the Northern European case is built from a DH operator point of view whereas the Central European

and Southern European cases are built from the perspective of a design office commissioned for decarbonisation studies for a region that could be supported by the government.

The Northern European case was studied to investigate NHES as replacement for heat sources relying on fossil fuel fired plants in the Helsinki Metropolitan area. The study conducted using the Backbone tool showed the interest of integrating SMR into DH networks. From the viewpoint of a district heating operator whose priority is to produce heat as a baseline, small heat only units like LDR-50 allows the operator to find profitability in the context of Helsinki area in the study presented in this document. The E-SMR is an academic concept with a heat recovery rate of 10% as assumed in the studies of this document. With the hypotheses from this case study, it would not meet a district heating operator's profitability expectations. Indeed, the study takes the point of view of a district heating network operator, does not look at the services rendered to the electricity grid or their remuneration. However, as E-SMR generates mainly electricity, its business model is highly dependent on the electricity market and the size of the power system. An indicator based on the system cost for the power system coupled with the district heating network would take into account the social welfare value of the E-SMR. Also note, that the heat recovery ratio of E-SMR could be increased in further studies to better fit expectations, taking into account the valorisation of the electricity production.

For the Central European case, the calculations performed have shown the potentiality to decarbonize the heat, electricity and hydrogen production with the help of SMR, electrolysis by Low Temperature Electrolyser and renewable energies (solar and wind). Results of the CEC can be easily utilized as for other similar territories like Silesian Voivodeship in Poland or Žilina self-governing region in the Slovak Republic.

For the Southern European case, the study allowed to identify a configuration with a decarbonisation of about 80% compared to the reference "business-as-usual" one for an extra cost of 26.1 €/MWh and 2.2 €/kg H<sub>2</sub>. This configuration contains E-SMRs, HTSE and hydrogen storage, and produce electricity, heat and low-carbon hydrogen. Furthermore, the flexibility offered by the E-SMR can be used to improve either the hydrogen cost or the carbon intensity of hydrogen in some extent. A carbon cost of 100 €/ton CO<sub>2</sub> eq would cancel the extra cost on the LCOE whereas a carbon cost of 172 €/ton CO<sub>2</sub> eq would completely cancel the extra cost of decarbonisation.

Additionally, even if the goal is not to compare the cases, the differences in LCOE and LCOH<sub>2</sub> between the most decarbonized cases of the Central European case and of the Southern European case can be explained. The main difference is the discount rate taken into account: 5% in the Southern European case and 7% in the Central European case. The higher the discount rate, the highest share of CAPEX in the LCO. This difference is responsible of about 10€/MWh in the

LCOE. Combined to more conservative assumptions (PV, PEM) considered for the components, the left differences can be explained. About 1.5 €/ kg H<sub>2</sub> is due to the difference between electricity cost considered in the calculation and to PEM technology conservative assumptions.

Overall, the report provides KPIs for NHES in three different locations in Europe each with their own context. In view of the results obtained, in all the cases, SMR can be an option to decarbonize HES. Nevertheless, depending on the application, the design and in particular the ratio between electricity and heat should be adapted.

**The objective targeted by the TANDEM project in this document is only to be demonstrative.** It is important to remind that the results obtained for the three case studies deeply rely on the assumptions taken into account. Besides, even if the present report gives a lot of numerical results, it is better to keep in mind the trends and not the exact values that are of course estimations based on a lot of assumptions. Finally, further sensitivity studies are also necessary to put in perspectives these results in sight of some uncertain assumptions that were taken into account.

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## 9 Annexes

### 9.1 Introduction to LCA

Life Cycle Assessment (LCA or E-LCA) is a tool to evaluate the environmental performance of products (goods, processes and services). The methodology of Life Cycle Assessment is formalised by the International Standards Organisation (ISO). According to ISO 14040-44, LCA is defined as “compilation and evaluation of the inputs, outputs and the potential environmental impacts of a product system throughout its life cycle”. LCA can be used in the context of decision-making to support product development, policy-making, strategic planning and so on as it facilitates the comparison between different processes studied according to the same parameters with the same methodology. LCA aims to evaluate the sustainability of a process, a product or a service along its life cycle steps.

The full assessment covers the entire life cycle of the studied product, process or activity from raw material extraction through materials processing, manufacturing, distribution, use, maintenance, and disposal or recycling. The environmental impacts of all the inputs and outputs flows occurring during these stages are evaluated.

LCA provides a set of environmental indicators representative of the consequences of an activity on several aspects of the environment (climate change, resource use, air and water quality, human health, etc.). The interpretation of LCA study all along life cycle stages enables the identification of major contributions to the environmental burdens and avoids potential issues of impacts shifting.

The standardised LCA framework encompasses four steps:

- **Goal and Scope definition:** First, the objectives and intended applications of the LCA study are explained. The system under study is defined, including its boundaries (conceptual, geographical and temporal), the life cycle stages considered, the quality of data and the main hypothesis applied. This step also include the description of the functional unit, a reference representation of the service provided by the system studied, for which the environmental impacts will be assessed or compared.
- **Life Cycle Inventory (LCI) analysis:** This phase is a technical process of data collection, in order to quantify the inputs of energy and raw material, and outputs of products, co-products, waste and emissions related to the system, as defined in the scope of the study.
- **Life Cycle Impact Assessment (LCIA):** Potential environmental impacts are calculated from the inventory using a selected assessment method to characterize the impacts



of each elementary flow. Dedicated software (SimaPro, GaBi, etc.) and databases (Ecoinvent) can be used for this purpose. The choice of impacts assessment method is adapted according to the goal and scope of the study; the Environmental Footprint method proposed by the European Commission is currently one more widely used solution.

- **Interpretation:** Results are presented and analysed to highlight the main sources of environmental impacts and potential comparison with reference system. Consistency of the results is evaluated through sensitivity analysis of modelling choices. LCA is an iterative process and the conclusions can lead to a revision of the aforementioned steps, for instance to evaluate a modification of the reference system, correct a modelling assumption or compensate low-quality or missing data.

Figure 86 gives a graphical view of the methodology showing the four steps.

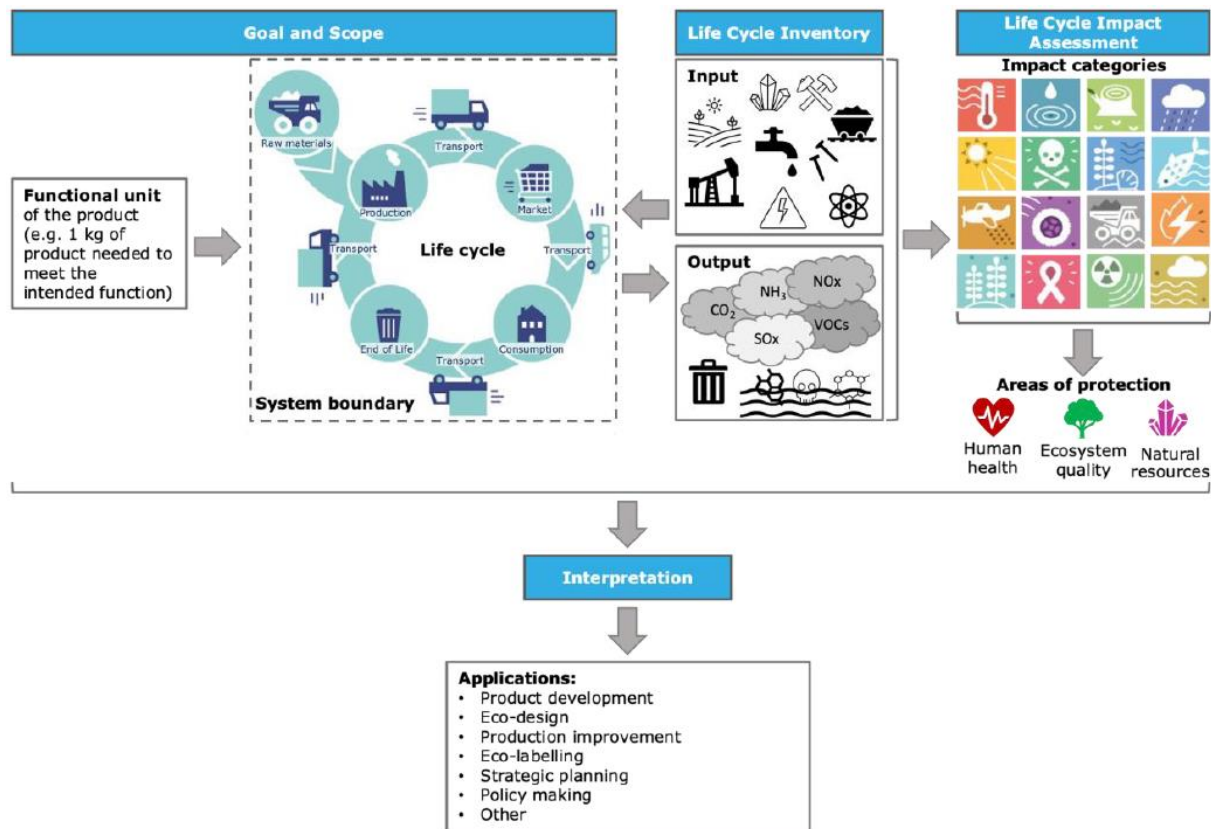


Figure 86: Generic workflow and applications of an LCA [63]

9.2 Additional results for Southern European case

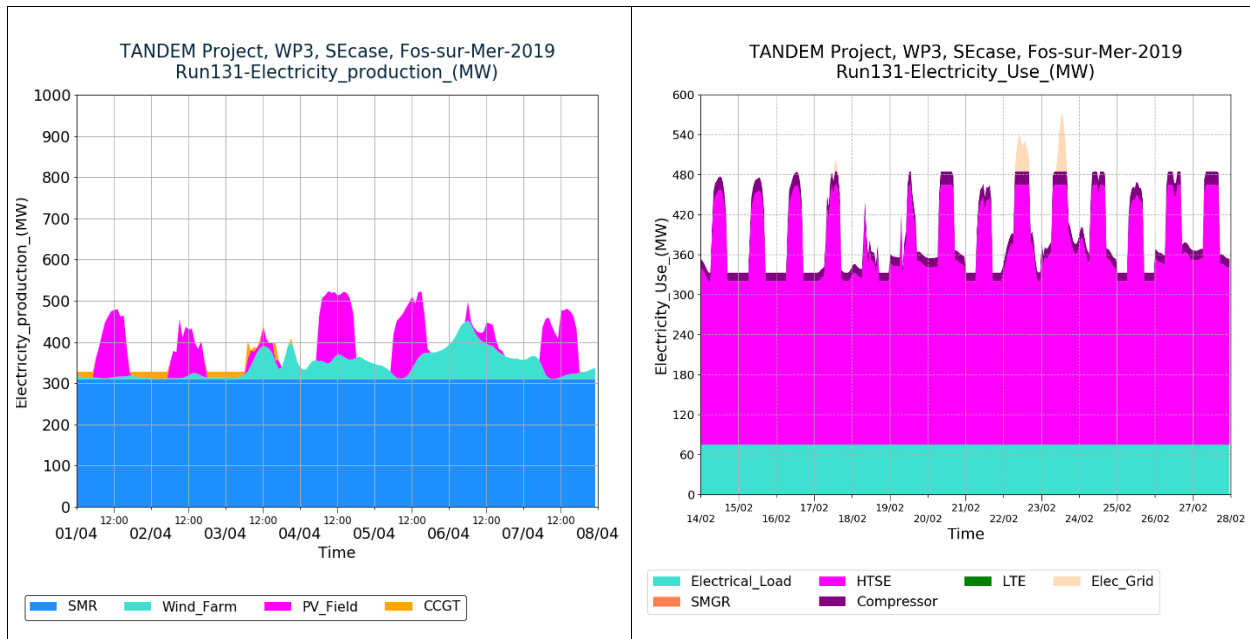


Figure 87: Fos-sur-Mer-2019, 2050 high SMR deployment scenario (run131), electricity production and consumption

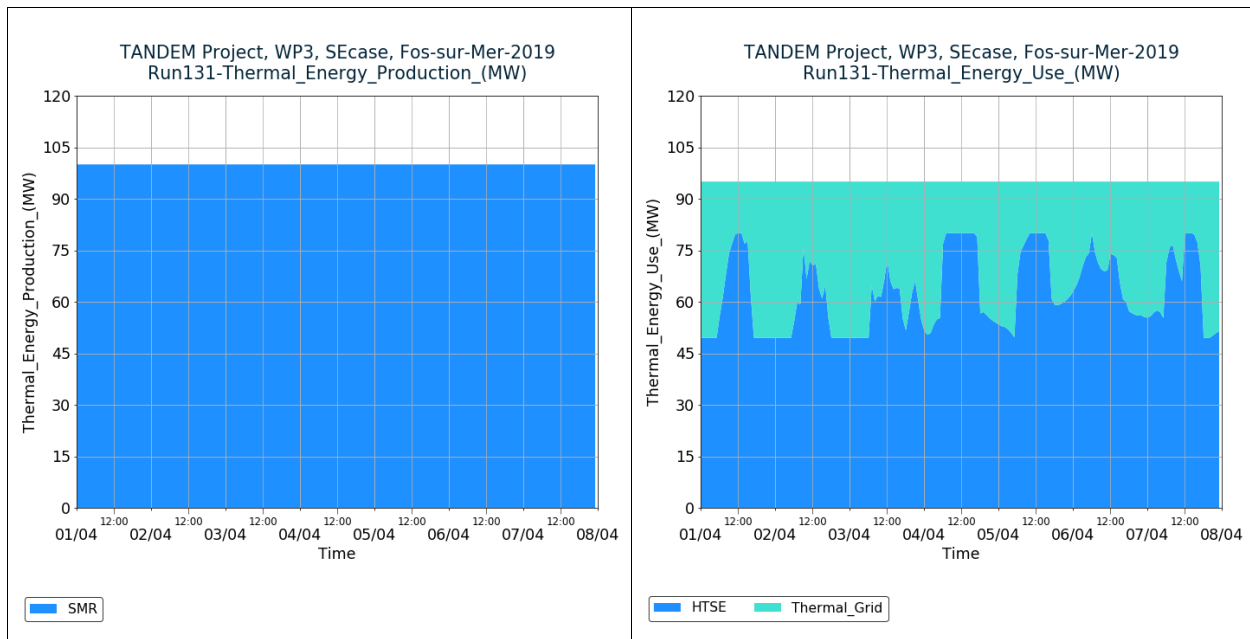
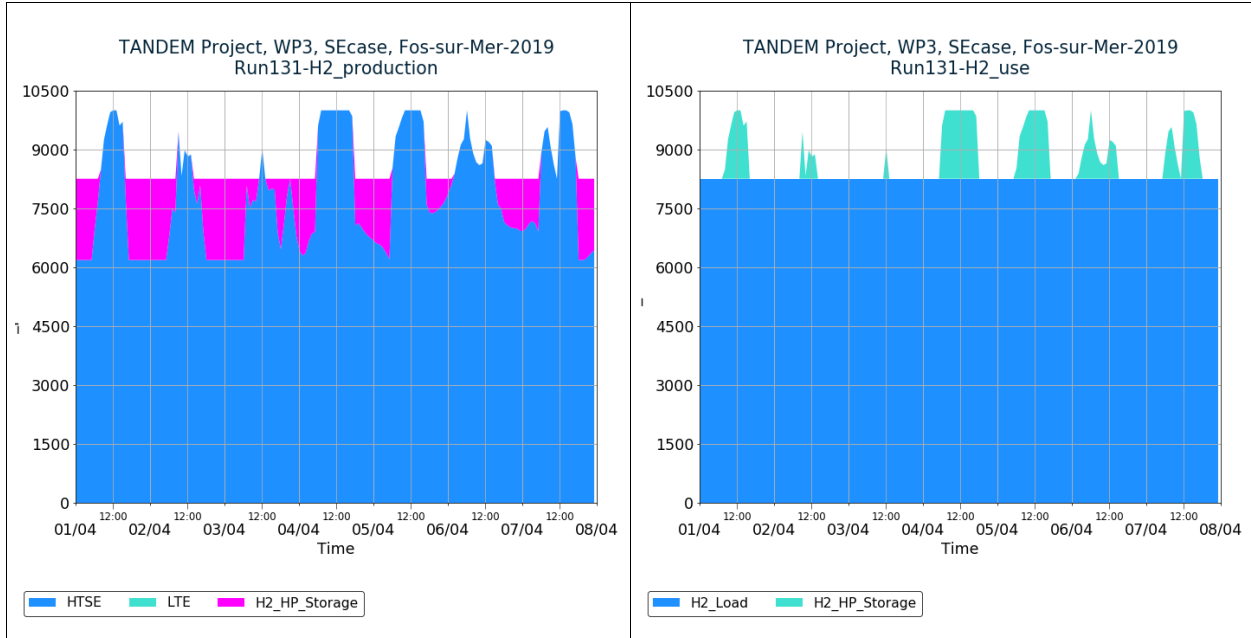
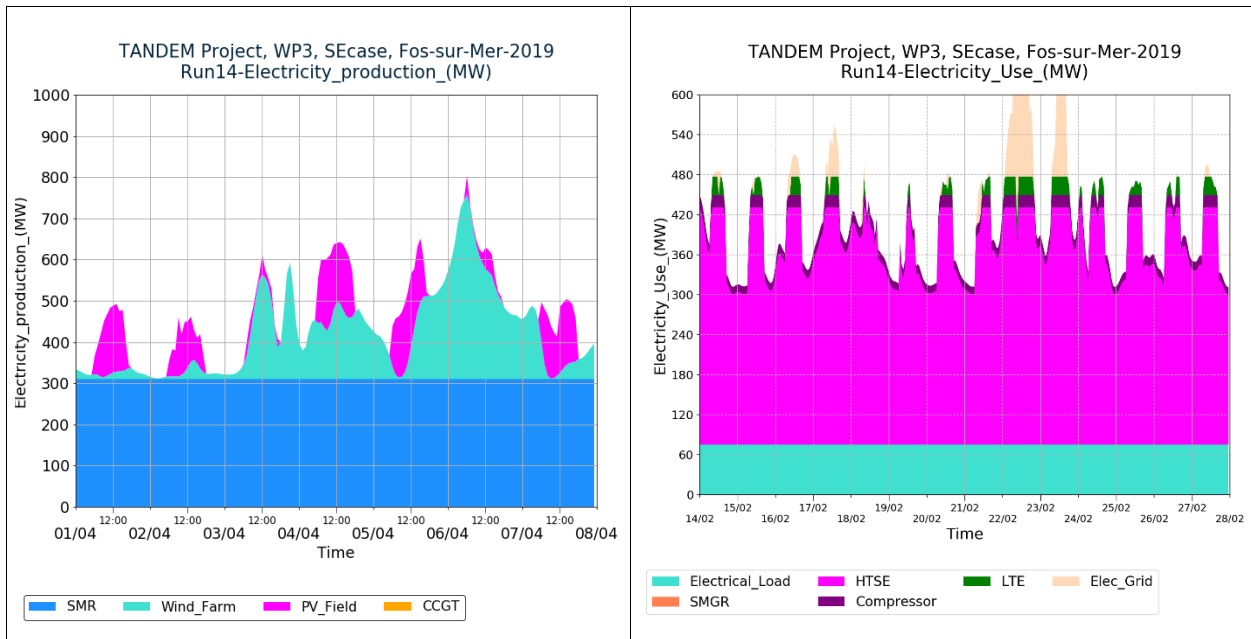


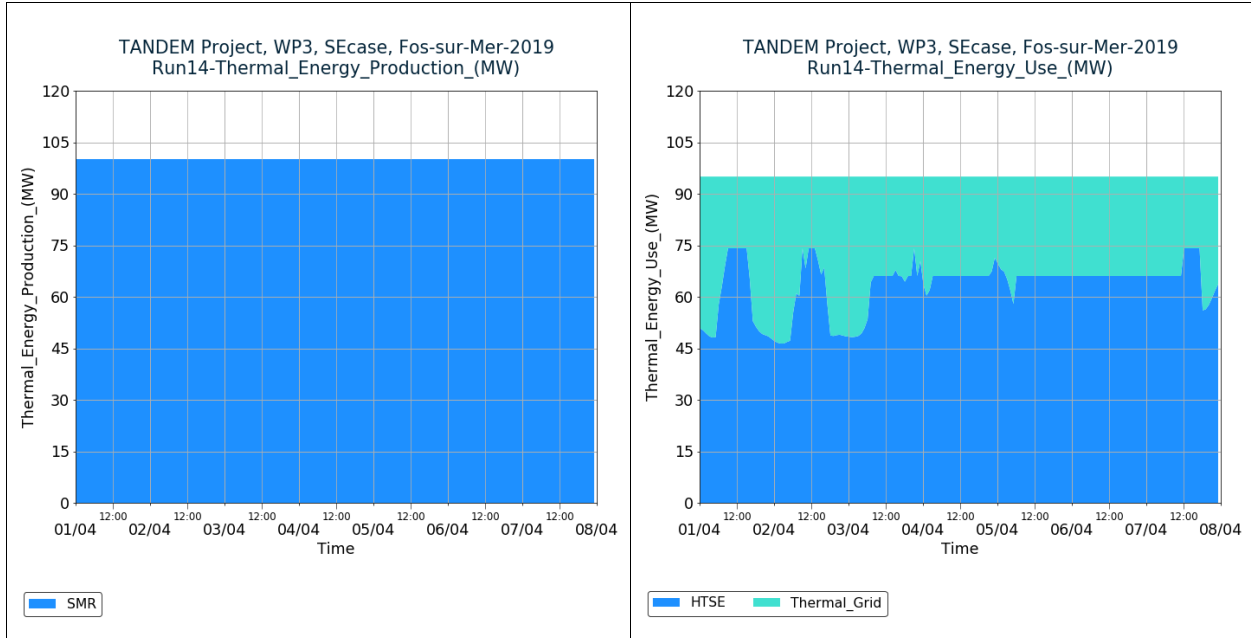
Figure 88: Fos-sur-Mer-2019, 2050 high SMR deployment scenario (run131), thermal production and consumption



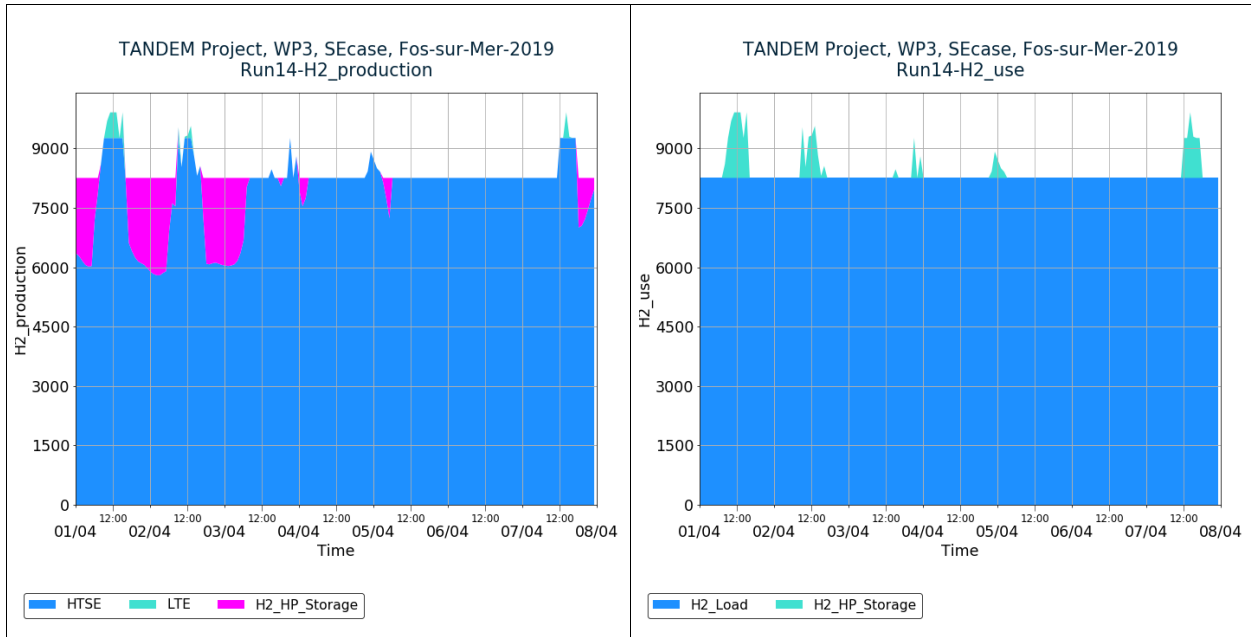
**Figure 89: Fos-sur-Mer-2019, 2050 high SMR deployment scenario (run131), hydrogen production and consumption**



**Figure 90: Fos-sur-Mer-2019, 2050 high SMR deployment scenario (run14), electricity production and consumption**



**Figure 91: Fos-sur-Mer-2019, 2050 high SMR deployment scenario (run14), thermal production and consumption**



**Figure 92: Fos-sur-Mer-2019, 2050 high SMR deployment scenario (run14), hydrogen production and consumption**