METIS 2

Technical Note T2

Energy system integration module

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1 Abbreviations and definitions

1.1 Abbreviations

Abbreviation	Definition
BECCS	Bioenergy plus CCS
CCGT	Combined Cycle Gas Turbine
CCS	Carbon capture and storage
DAC	Direct air capture
DSR	Demand Side Response
EEZ	Exclusive Economic Zone
EFLH	Equivalent full-load hours
LCOE	Levelized cost of electricity
LF	Load factor
NTC	Net transfer capacity
OCGT	Open Cycle Gas Turbine
PPA	Power Purchase Agreement
PV	Photovoltaic
RES	Renewable Energy Sources
vRES	Variable RES

1.2 METIS configuration

The configuration of the METIS model used to evaluate the impacts of the MDI policy measures is summarised in Table 1.

Table 1 - METIS Configuration

METIS Configuration	
Version	METIS v2.0 Beta (non-published)
Modules	Energy system integration module
Scenario	METIS 2050 scenario
Time resolution	Hourly (8760 consecutive time-steps per year)
Spatial granularity	Member State

2 INTRODUCTION

This Technical Note introduces the newly developed METIS features that extend the tool capabilities to represent multi-energy systems and facilitate the assessment of energy system integration strategies, namely, a joint-optimisation of the power, hydrogen and industrial heat systems. This allows for an enhanced quantification of synergies resulting from sector coupling. Such flexibility alleviates the constraints on the system. This brings down operation cost by reducing the need for peak-load technologies and may allow for a more limited dimensioning of infrastructure, thus lowering investment needs to meet the energy demand.

This Technical Note details the different developments brought to the latest version of the METIS model in the context of the METIS 2 project. They result in a more refined model of a climate-neutral 2050 energy system – or of the pathway to reach such a system. Four main developments were carried out.

First, the model includes newly developed **cost-potential curves for renewable generation**. These cost curves allow for a more precise capacity expansion model, as they provide information about RES potentials clustered by costs considering the location-specific variation in load factors across a country (instead of a single technology-specific cost value for an entire country). In case of RES-E capacity optimisation, investments materialise in the most favourable locations, in terms of load factors and capacity costs, allowing for a more detailed and realistic representation of RES-E deployment.

Second, the model extends its usual gas-electricity perimeter to cover the **Power-to-X** chain, with a focus on **hydrogen and industrial heat supply**. To complete the P2X chain, hydrogen can be further converted into synthetic gas (also referred to as e-gas). To better reflect techno economic constraints from the industry, the heat supply is distinguished by three distinct temperature levels. The capacity and dispatch optimisation ensures that the supply and demand equilibrium is met at each temperature level. Along with the industrial heat supply, residential heat supply is considered, too, especially when it provides flexibility to the power system thanks to hybrid heat pumps.

Third, an emphasis has been made on the scarcity of **bioresource availability** (biomass and biogas). As it provides both potential negative emissions and flexible generation, bioresources are key in a carbon-neutral system. Hence the model has been extended to account for their limited availability, and ensure a cost-efficient use of this resource.

Eventually, the flexibility portfolio has been extended. An **upgrade of the hydro power model** has been performed, to better reflect water management in reservoirs under uncertainty. As one of the potential future key technologies to meet climate neutrality, **CCS** has been included in the model, too.

Figure 2-1 describes the complete perimeter of the optimisation and modelling scope of the METIS 2 energy system integration module. Along with the P2X chains and the limited bioresources potential, one can observe the CCS option considered for selected power/heat generation technologies and the distinction between the three temperature levels of industrial demand plus the related heat supply technology portfolio available for capacity optimisation.

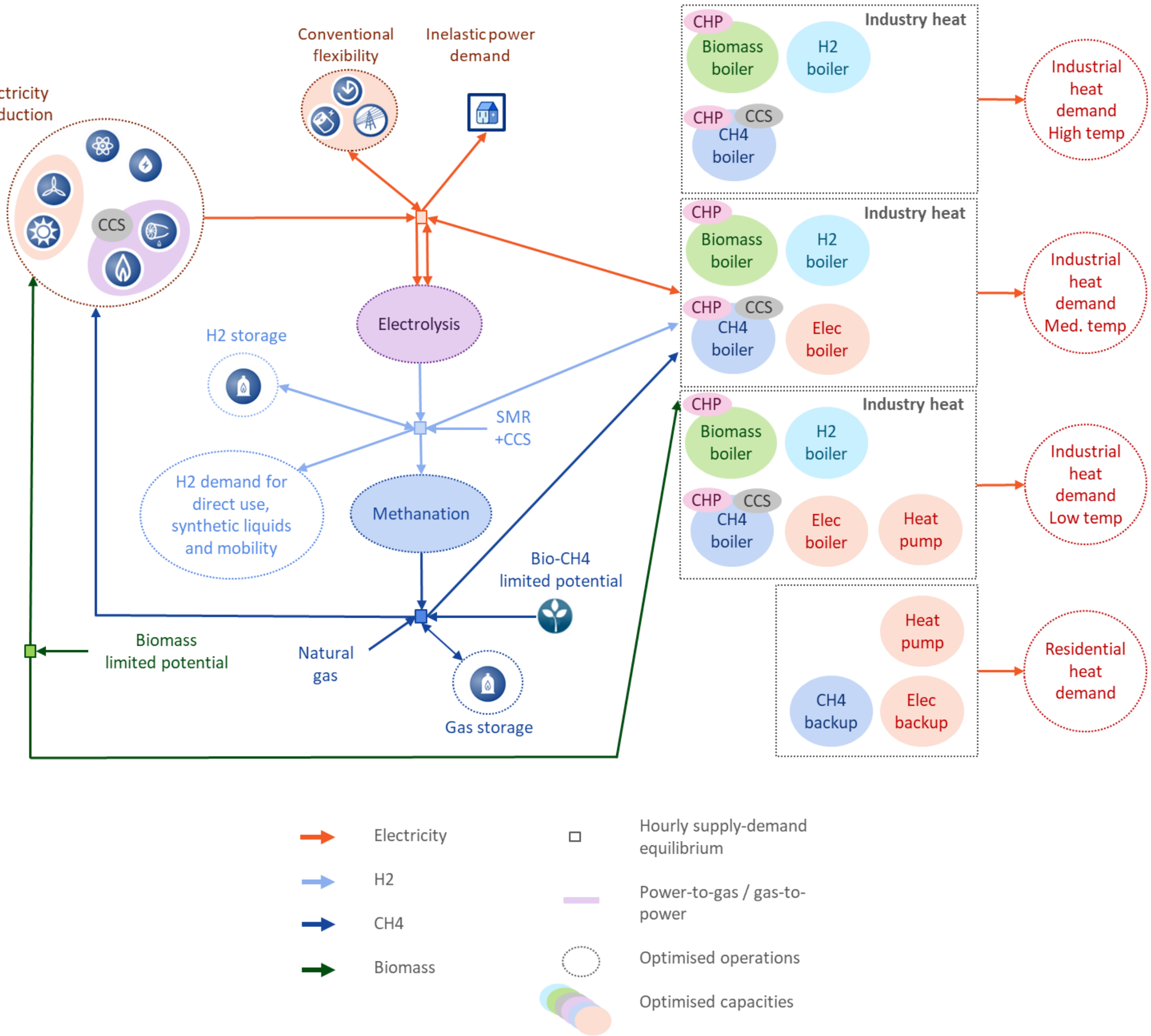

Figure 2-1: METIS optimisation scope in the energy system integration module

Three different **METIS studies** made use of this upgraded METIS version, namely studies S3, S4 and S6. They respectively focus on the role of hydropower in a decarbonised system, on 2050 no-regret options and technology lock-ins, and on the cost-optimal balance between direct electrification and the use of decarbonised gases[1].

The remainder of this technical note is structured as follows. Section 3 introduces the use of supply cost curves in the capacity optimisation of variable renewable energy sources. Section 4 presents the power-to-X chain, i.e., how METIS modelling features have been upgraded to cover power-to-gas (including hydrogen) and power-to-heat (for residential and industrial end-use heat demand) conversion. Section 5 details how limited availability for bioresources is considered in the modelling, and Section 6 focuses on the refinements in the hydro power and thermal generation flexibility provision. Section 7 lists the METIS scenarios making use of the energy system integration module. A detailed review of the annual hydro generation dataset can be found in the Annex.

[1] (Engie Impact, Artelys, 2022), (Comillas, Artelys, 2021), (Artelys, 2022)

3 Capacity optimisation of variable renewable energy sources

3.1 Optimising renewable capacities

Renewable electricity plays a key role in a 2050 climate-neutral energy system. Direct electrification (e.g., via electric vehicles in transport or heat pumps in buildings) allows to replace technologies running on carbon-intensive fuels. Indirect electrification (through power-based generation of carbon-neutral energy carriers such as hydrogen or synthetic fuels) facilitates the decarbonisation of hard-to-abate sectors. Yet, this implies that demand for decarbonised, renewable power will increase significantly. The EU's Long-Term Strategy[2] (LTS) projects power demand to double by mid-century compared to 2015. Accelerated renewables deployment needs to keep pace with this evolution. In 2050, the LTS's 1.5TECH scenario foresees 760 GW of onshore wind, 450 GW on offshore wind and 1030 GW of PV in the EU27+UK as key enablers to deliver climate neutrality.

Renewable generation is mainly characterised by its diversity, either in terms of technology, investment cost, potential or production pattern. Solar generation can consist in utility-scale facilities, large group of solar panels on commercial building roofs, or decentralised installations on residential buildings. Wind generation can be onshore or offshore, the latter typically being divided between bottom-fixed or floating turbines. Installations can be further distinguished based on their investment costs (depending on the technology) and their load factor, which depends largely on local conditions. Each of the previously-defined technology groups features a limited potential, meaning that installing renewable facilities can only be done in places with the most favourable conditions up to a given capacity, after which further installation could only be done at the expense of a higher cost or lower renewable generation.

In a cost-efficient energy system, the levelized cost of renewable electricity necessarily increases as the system integrates more renewables, making places with favourable conditions scarcer. A cost-potential curve translates the relationship between the two variables. In order to accurately model capacity optimisation of variable renewable energy sources, cost-potential curves are constructed and included in the METIS energy system integration module.

Each LCOE range can only be exploited up to a given potential. The joint capacity and operation optimisation performed in METIS commissions the respective potentials in a cost-efficient order. As the optimisation is performed at hourly resolution, generation profiles also affect the category of investments that should be made. Categories featuring a profile which is more aligned with the power demand requires lower contributions from flexible technologies, therefore reducing the system integration costs. E.g., offshore wind technologies have higher investment costs but offer a more balanced generation profile that may prove useful in reducing flexibility needs.

Additional constraints can be set to force a minimum bound on a technology's total capacity in a given zone, disregarding the shape of the cost-potential curve. This constraint accounts for a minimum deployment due to already existing capacities or planned increases.

[2] (European Commission, 2018)

3.2 CONSTRUCTION OF COST-POTENTIAL CURVES AND INTEGRATION INTO METIS

Cost-potential curves are built at the country-level. In a nutshell, they capture:

- limited potential due to available space or social acceptance,
- related costs, such as investment and installation costs depending on installation site, and
- renewable generation patterns (i.e., load factors depending on installation site) and their impact on variable costs.

For each technology, steps of the cost-potential curves based on different LCOE ranges are defined, under the following assumptions:

- Onshore wind installations mainly differ based on their exposure to wind flows and consequently may have large variations in their load factors from one installation to another, while the investment cost remains relatively stable.
- The rather uniform off-shore wind distribution enables to consider a similar load factor across offshore wind plants of a given country, yet the installation costs differ a lot between bottom-fixed and floating technologies and increase with the distance to the shore.
- Solar panels may be installed either on residential, commercial buildings or ground-mounted, typically referred to as utility scale, and investments benefit from economies of scale when commissioned on larger surfaces. Load factors vary depending on the panel orientation and localisation in the country.

Potentials and load factors are derived from the ENSPRESO database[3], and costs from the ASSET Study[4]. The matching process between the ENSPRESO database and METIS vRES cost-potential curves is performed applying the following methodology:

- For onshore wind, ENSPRESO's "reference" scenario provides the distribution of load factors and potentials. Five categories are extracted from the load factor distribution: load factors between 15% and 20%, load factors between 20% and 25%, and three additional categories for load factors above 25% – the 10% best, between 10% and 50%, and the remainder (50% to 100%). For each category, the average load factor and its respective potential are computed. All five categories are supposed to share the same investment cost.
- For offshore wind, the "low restrictions beyond 12 nm" scenario is considered. This scenario facilitates large development levels as foreseen in the LTS. The database distinguishes different water depths: 0 to 30m, 30 to 60m (bottom-fixed), 60 to 100m (floating) and beyond 100m (floating). Each water depth is associated to a potential. Capacity costs are assigned depending on the technology and the water depth. Only one average load factor per Exclusive Economic Zone is considered, which is the same across the four categories.
- The ENSPRESO PV database provides for each surface type (utility scale, residential or commercial rooftops) surfaces and irradiation from which are derived load factors and potentials. These potentials are then aggregated into three groups (10% best,

[3] (P. Ruiz, 2019)

[4] (E3Modelling, Ecofys, Tractebel, 2018)

between 10% and 50%, and the remainder – similarly as for onshore wind). A specific capacity cost is assigned to each surface type, resulting in a total of nine LCOE categories for PV.

Figure 3-1 to Figure 3-3 display the outcome of the clustering process per technology per country. Figure 3-4 and Figure 3-5 display the aggregated cost-potential curves for Germany and Italy. One should note that the least-cost categories are not necessarily the first ones commissioned, as the generation profile is determinant in the hourly optimisation.

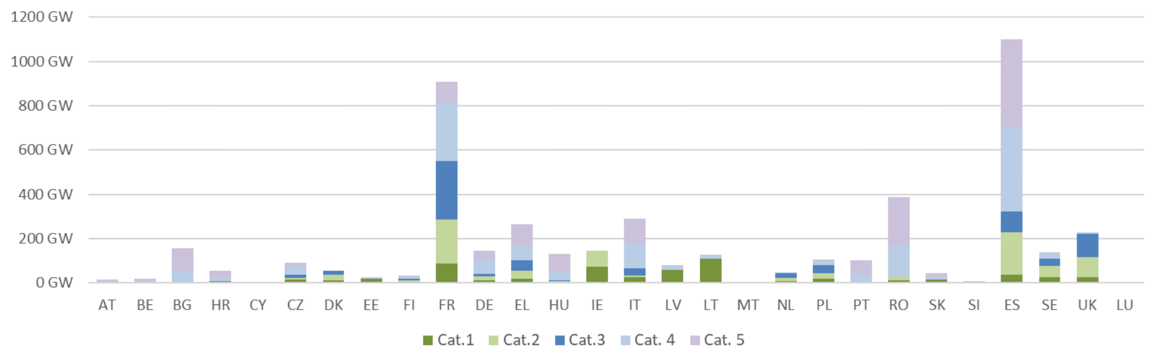

Figure 3-1: Onshore wind capacity potential (GW) by category.
For load factor (LF) above 25%, cat.1: 10% best, cat.2: 10% to 50%, cat.3: remainder
Cat.5: LF between 15% and 20%, cat.4: LF between 20% and 25%

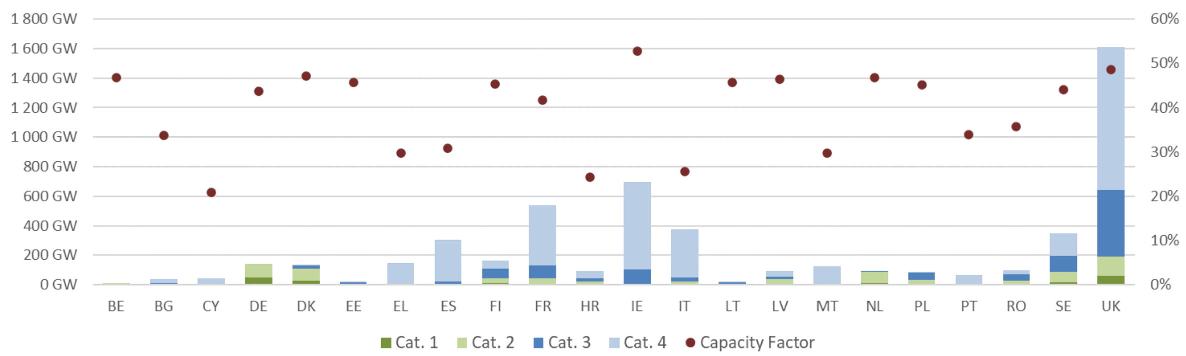

Figure 3-2: Offshore wind capacity potential (GW) by category and respective capacity factors[5].
Cat.1: 0-30m, cat.2: 30-60m, cat.3: 60-100m, cat.4: 100-1000m water depth

[5] As discussed above, the same capacity factor is used for all offshore wind turbine categories in a given country.

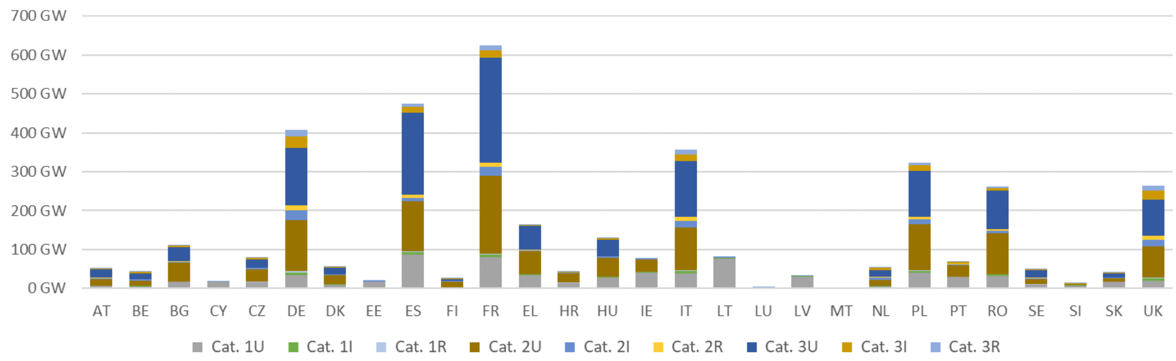

Figure 3-3: PV capacity potential (GW) by category.
Cat.U: utility scale, cat.I: commercial buildings, cat.R: residential buildings
Cat.1: 10% best, cat.2: 10% to 50%, cat.3: remainder

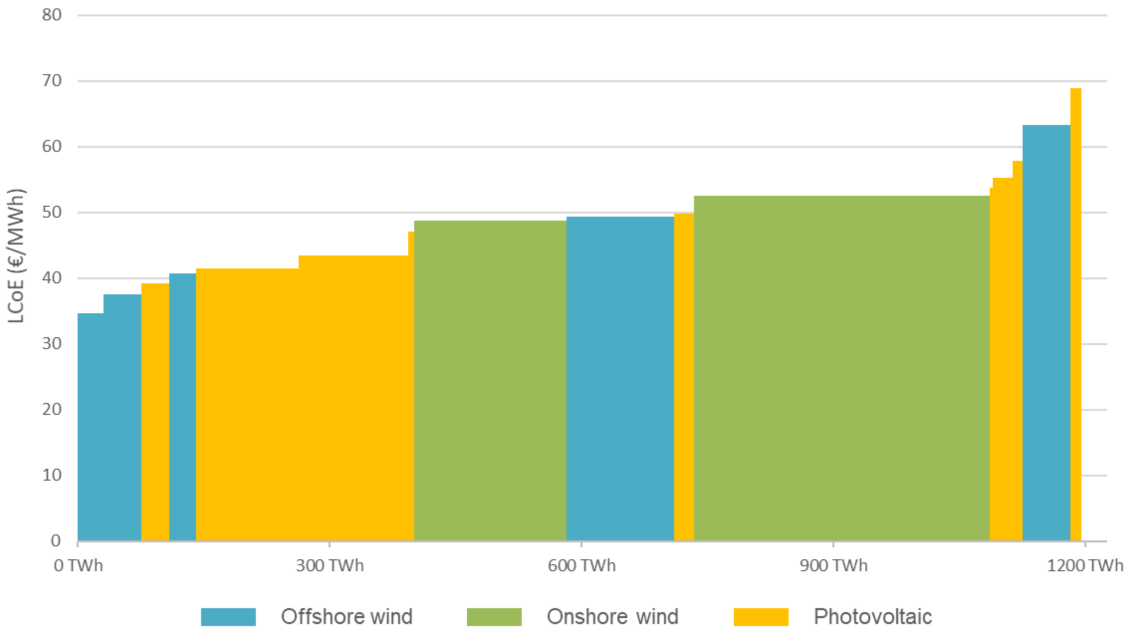

Figure 3-4: vRES cost-potential curve in Germany – derived from ENSPRESO

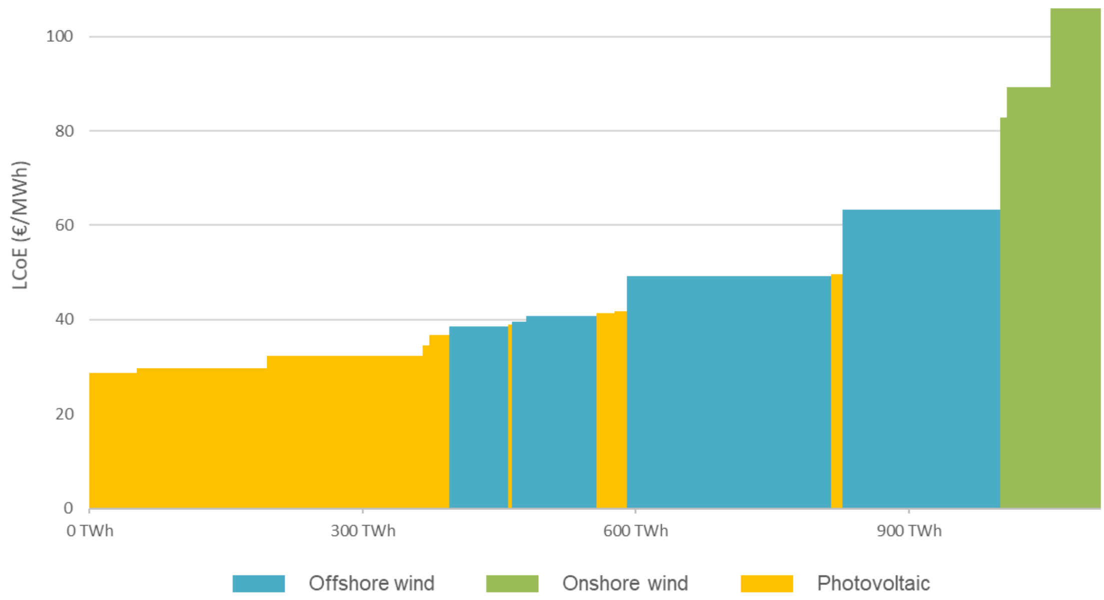

Figure 3-5: vRES cost-potential curve in Italy – derived from ENSPRESO

As the ENSPRESO database perimeter is limited to the EU27 and UK countries, proxies are used to build cost-potential curves for CH, NO and the Balkans, which are respectively derived from AT, SE or UK, and HR. The following parameters are considered for the proxy:

- For onshore wind: the country surface,
- For offshore wind: the coastal perimeter and the EEZ surface,
- For utility-scale PV: the country surface,
- For rooftop PV (either residential or commercial buildings): the country population.

The cost-potential curves are then integrated in METIS by creating one asset per category. Each asset is parametrised with the average load factor of the category, the average investment cost of the category, and the capacity potential of the category. If necessary, generation profiles are adapted to match the expected load factor.

METIS co-optimises the investments in each category, accounting for each of the previously mentioned parameters.

4 The Power-to-X chain

A 2050 climate-neutral European energy system relies on a strong coupling between energy vectors, and in particular electricity and gaseous fuels. Electricity can be converted in hydrogen and its derivatives (e-gas and e-liquids) while gaseous fuels can provide flexibility to the power system when needed, either on the supply side for peak generation or on the demand side as substitutes to electricity consumption for some end-uses, and in particular heat supply.

A climate-neutral energy system can only be designed accounting for the interlinkages between electricity and the other energy vectors. To this end, METIS has been upgraded towards an integrated energy system model. In particular, the multi-energy approach accounts for the coupling of the power system with the gas, hydrogen and heat systems by performing joint investment and dispatch optimizations over the four vectors.

This section describes the power-to-X conversion chain, which includes a hydrogen and an e-fuel layer, along with a residential and an industrial heat layer.

4.1 System integration: Power-to-Gas

In order to integrate the power-to-gas chain into METIS, hydrogen has been included as an additional energy carrier, with dedicated assets for hydrogen production and consumption ends (electrolysis and methanation). Figure 4-1 displays the hydrogen and e-gas layers of the energy system integration module.

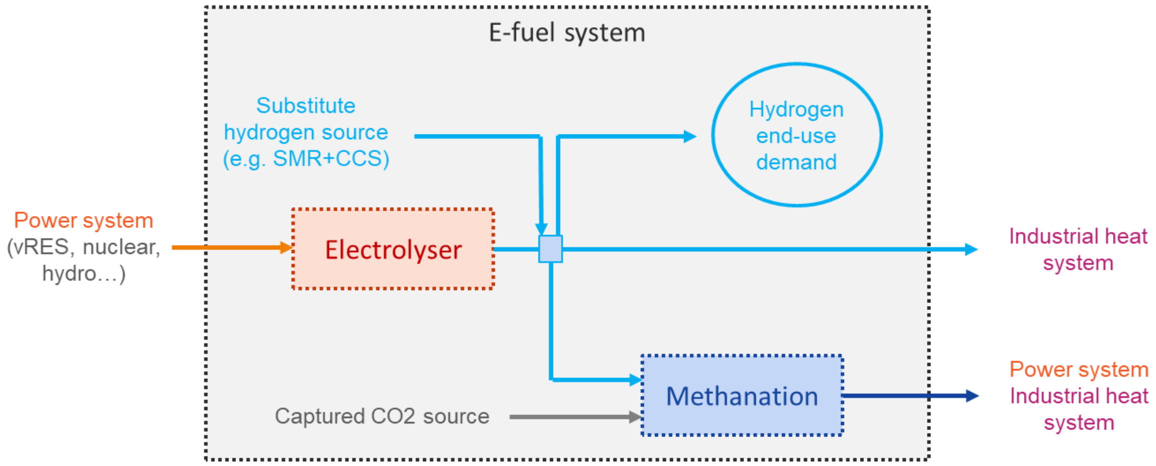

Figure 4-1: Hydrogen and e-gas systems

4.1.1 Hydrogen layer

Hydrogen is intricately linked to electricity in a 2050 energy system: it can be produced cost-efficiently based on renewable surpluses, then stored over long time-periods and later consumed when power demand significantly exceeds supply.

The hydrogen layer of the modelling includes hydrogen production technologies, hydrogen storage plus transmission infrastructure, and hydrogen end-use demands (e.g., ammonia production, refineries, mobility…).

Hydrogen generation

Hydrogen generation is endogenously integrated in the model:

- Either with **electrolysers** that consume electricity and deliver hydrogen with respect to the assumed technology efficiency,
- Or with a **hydrogen supply** that represents a substitute hydrogen source such as steam methane reforming combined with CCS (SMR+CCS) or hydrogen imports.

Electrolysers are modelled as electricity consumers and hydrogen producers, and are characterized with the following set of parameters: a generation capacity, an availability timeseries, variable operation and maintenance costs, and an efficiency that links proportionally electricity consumption and hydrogen generation. When the optimisation includes the optimal sizing of investments, the capacity parameter is transformed into lower and upper capacity bounds along with associated capacity costs (yearly CAPEX and yearly fixed operation costs). In such a case, both the electrolyser sizing and operation are optimized jointly.

Several electrolyser technologies would be available by 2050, namely alkaline cells, proton exchange membrane cells (PEM) or solid oxide electrolyser cells (SOEC). The three technologies have different capacity costs and efficiencies, SOEC featuring the highest efficiency along with the highest capacity costs[6]. In METIS, one can either integrate the three technologies in the system and determine the optimal electrolyser mix, or limit the model complexity on the basis of a calibration run with framework assumption to determine the most appropriate technology. Under LTS 1.5TECH assumptions, the alkaline technology proves to be the most cost-efficient one, with its lower capacity cost and a relatively higher efficiency.

	Investment cost (€/kW)	Fixed O&M costs (% CAPEX)	Efficiency	Lifetime
Alkaline	180	5%	85%	20
PEM	200	5%	85%	20
SOEC	600	7%	96%	20

Table 2: Technical parameters for electrolyser technologies[7]

In METIS, electrolyser operation is assumed to be perfectly flexible at no additional costs. As such, electrolysers can follow the residual load evolution over time[8], helping to harness the full potential of variable generation (solar, wind), and are one of the main flexibility contributors to the power system flexibility needs in the METIS 1.5TECH scenario.[9]

Beyond hydrogen generation via power-to-hydrogen, alternative hydrogen generation sources can be modelled as a hydrogen supply contract, whose variable cost is derived from SMR+CCS technoeconomic parameters, i.e., from gas and CO2 prices combined with process efficiency. Depending on the assumptions, the hydrogen supply can also represent imports from outside the EU, if associated to another cost.

Hydrogen demand

[6] (E3Modelling, Ecofys, Tractebel, 2018)

[7] Derived from the ASSET study (E3Modelling, Ecofys, Tractebel, 2018)

[8] As a reminder, the simulation is performed at the hourly resolution

[9] (Artelys, 2022)

As for the gas layer[10], an inelastic hydrogen demand has been included in the model. It accounts for all the exogenous end-uses of hydrogen, either in the industry, transport or buildings sector. This hydrogen demand does not include the end-uses which are explicitly represented and optimized in the model, such as industrial heat supply.

Hydrogen infrastructure

The hydrogen infrastructure is integrated into the METIS model based on a similar approach than for the gas infrastructure[11]. Namely, hydrogen storage assets and hydrogen interconnection pipes complete the existing model and provide temporal and spatial flexibility.[12]

Coupling between the gas and hydrogen transport infrastructure in the form of allowing the model to repurpose existing gas pipelines into hydrogen pipelines is not covered by the energy system integration module. Study S4 implicitly covers the potential for repurposed gas pipelines, by defining a maximum capacity of hydrogen pipelines that could materialise at a lower cost (repurposing cost) than investments in new hydrogen pipelines. The reduction in gas transport capacities is not captured by the model. Yet, it has limited implications as Study S4 does not explicitly model the gas system (hence the gas infrastructure).

The hydrogen infrastructure can be parametrised to better reflect assumptions on hydrogen demand flexibility. In Study S6, hydrogen demand is represented as flexible via an inelastic demand coupled to a storage whose capacity can be parameterised to represent either weekly, monthly or annual hydrogen demand-side flexibility[13].

4.1.2 E-FUEL LAYER

Hydrogen can either be consumed as such or converted further along the P2X chain in its derivatives, namely e-gas and e-liquids. E-gas is understood as CH4 produced from methanation and e-liquids as carbonated chains produced from the Fischer-Tropsch process. For complexity purposes, e-liquids and e-gas end-use demands are factored in the hydrogen end-use demand, factoring in the conversion efficiency of methanation and Fischer-Tropsch.

Yet, the model also accounts for an endogenous production of e-gas, which can be injected in the gas network, stored, and consumed in the power and heat systems. It represents one of the CH4 sources in the energy system, along with natural gas and biogas.

Methanation is modelled as a hydrogen consumer and a methane producer. It also consumes CO2 as a carbon source for the process. It features the following parameters: a generation capacity, an availability timeseries, variable consumption costs, and two coefficients that link proportionally methane generation with hydrogen and CO2 consumptions. When the simulation includes the optimal sizing of investments, the capacity parameter is transformed into lower and upper capacity bounds along with associated capacity costs (yearly CAPEX and fixed operation costs). In such a case, both the methanation sizing and operation are optimized.

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[10] (Artelys, 2018)

[11] (Artelys, 2018)

[12] It should be noted that Study S6 does not consider cross-border exchanges of hydrogen, and therefore does not integrate hydrogen pipelines in the study model.

[13] See Study S6 sensitivity analysis for an assessment of hydrogen demand-side flexibility.

It should be noted that as both inputs and outputs of the technology are storable gaseous fuels, the capacity factor resulting from the operation optimization is often close to maximum availability (yet depending on the size of gas and hydrogen storages).

CO2 consumed for methane production could come from different sources: carbon capture and storage (CCS) on power generation (either fossil fuels or bioenergy), CCS on industries, or Direct Air Capture (DAC). A model for captured CO2 is needed to account for flows from CCS-equipped plants to the methanation asset. In the absence of a holistic model for CO2 capture which would require an extensive dataset of cost-potential curves and other parameters from various sections of the economy which are not represented yet in METIS, an assumption on CO2 source is made. For instance, Study S6 considers CO2 from Direct Air Capture, both providing an estimation of capture cost and a guarantee of renewable origin for CO2 consumption in e-gas generation[14]. CO2 production cost on the DAC-route is estimated at 200 €/t.[15]

	Investment cost (€/kW)	Fixed O&M costs (% CAPEX)	Efficiency	Lifetime
Methanation	263	3,5%	79%	25

Table 3: Technical parameters for methanation[16]

4.2 System integration: Power-to-Heat

4.2.1 Heat sector coupling: Residential heat

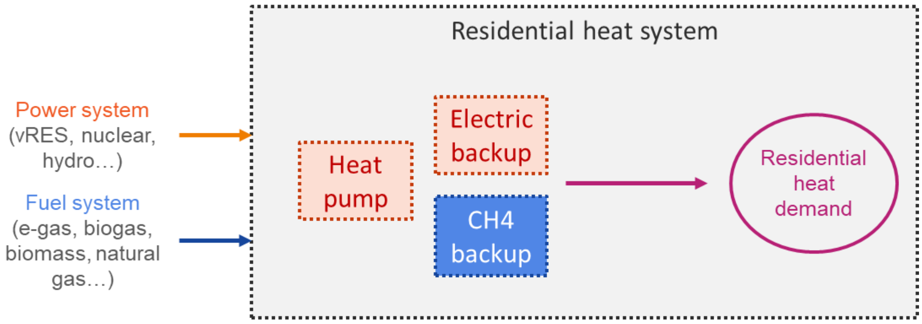

Figure 4-2: Residential heat system

An extension of the existing residential heat pump model is developed in the energy system integration module. As a reminder[17], the functioning of the heat pumps is simulated by optimising the hourly operation of the nationally aggregated heat pumps and heat back-up capacities in order to meet the hourly heat demand at lowest costs, taking into account that heat demand, heat pump coefficient of performance (COP) and heat pump output capacity vary in function of the ambient temperature. The operation of the heat pump

[14] CO2 captured from industries running on fossil fuels would have a higher carbon footprint and would not provide guarantee on the renewable origin of e-gas. An enhanced model of captured CO2 would consider a mix of CO2 sources with variable costs and carbon footprints.

[15] (European Commission, 2018)

[16] Derived from the ASSET study (E3Modelling, Ecofys, Tractebel, 2018)

[17] See (Artelys, 2018) for detailed explanations on the existing model

systems is jointly co-optimised with the hourly dispatch of all European power generation, transmission and storage assets.

The energy system integration module extends the existing model by allowing two heat backups instead of one, and jointly optimises their respective capacities and operation instead of assuming an exogenous sizing of the backup.

The sizing of the heat pump system is a trade-off between the CAPEX and the OPEX of the two technologies. A heat pump is a rather expensive system, but due to its very high efficiency it ensures heat production at a reasonable price. On the other hand, an electric or gas boiler has lower investment costs but much more important variable costs (in particular fuel costs).

Given the previous considerations, heat pumps are often designed to cover a share of the useful heat demand, the remainder being covered by the backups. Generally, it is assumed that the heat pump covers 95% of the useful heat demand while the backups supply the remaining 5%[18].

Yet, even if the price ratio between gas and electricity may be rather stable in current energy systems, enabling an informed choice between gas or electric backups, decarbonised energy systems may see large variations in electricity prices given the variability of renewable production. In an effort to better integrate renewables in the electricity system and reduce the system costs, an electric backup would increase electricity consumption in times of renewable surpluses whereas the gas backup would decrease tension on the power system if renewable generation was to shrink.

In addition, the joint capacity optimisation of both boilers enables a cost-efficient design of heat pump systems. Each country would have its own arbitrage between investing in gas or power backup heaters, based on endogenous gas and power prices, and on capital costs. Backup heaters' technoeconomic parameters are displayed Table 4.

	Investment cost (€/kWth)	**Fixed O&M costs (% CAPEX)**	**Efficiency (HHV)**	**Lifetime**
Gas back-up	220	-	86%	25
Electric back-up	140	-	100%	25

Table 4: Techno-economic parameters for backup heaters[19]

Figure 4-3 displays the typical operation of a heat pump equipped with two backup heaters. In addition to the operation of the heat storage, the backups supply peak heat demand, either fuelled with electricity or gas depending on the endogenous electricity and gas prices. Their capacities are optimised with respect to the electricity and gas price variations over the year.

[18] (Artelys, 2018) and (Artelys, 2018)

[19] Derived from the ASSET study (E3Modelling, Ecofys, Tractebel, 2018)

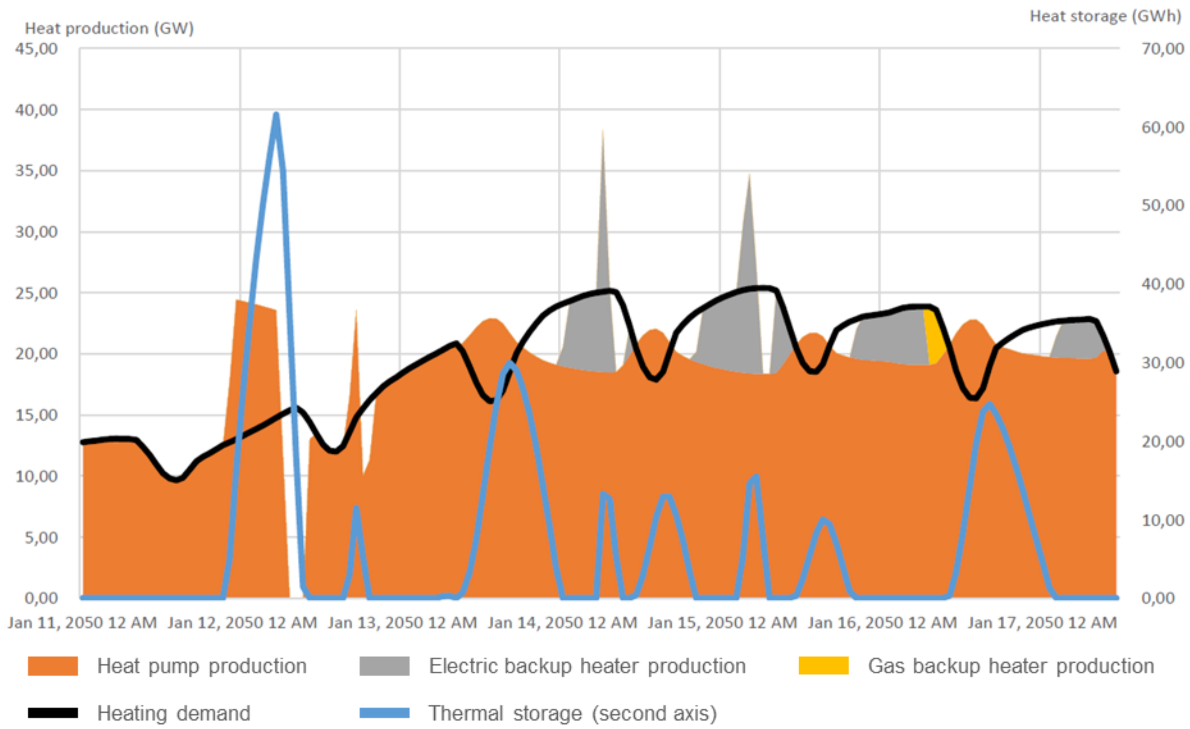

Figure 4-3: Typical heat-pump operation in winter

4.2.2 HEAT SECTOR COUPLING: INDUSTRIAL HEAT

As a large share of industrial heat demand can be met by different heat supply technologies (no specific constraint on the input fuel or corresponding technology), the latter falls into the scope of the integration module of METIS. Therefore, a joint optimization of the power sector and the industrial heat sector can be performed, reaching a more cost-effective balance with respect to gas and electricity supply.

Industrial heat generation

A literature review has been performed to identify the technologies able to provide industrial heat[20]. It highlights the need to separate heat supply technologies per temperature level, as most technologies can only deliver heat for a specific temperature range. The ranges are defined as follows:

- Low temperature level: below 150°C
- Medium temperature level: between 150°C and 500°C
- High temperature level: above 500°C

The different heat supply options considered for the three temperature levels are schematically listed in Figure 4-4 to Figure 4-6.

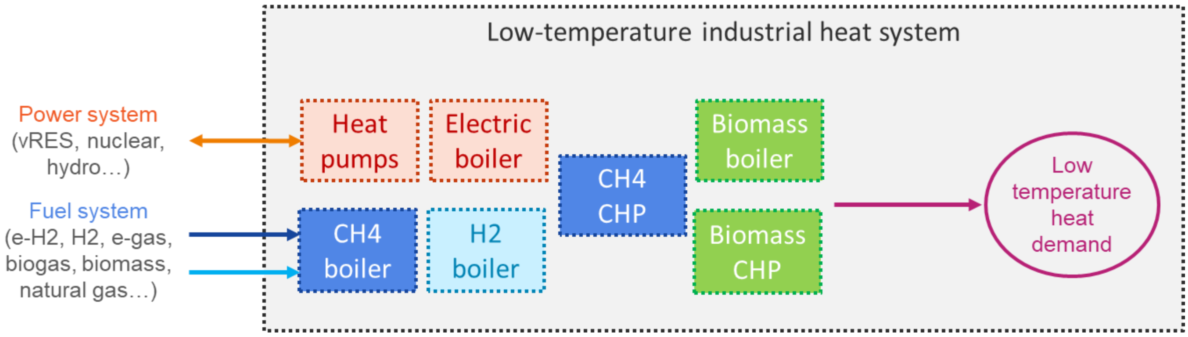

Figure 4-4: Industrial heat system – low temperature heat

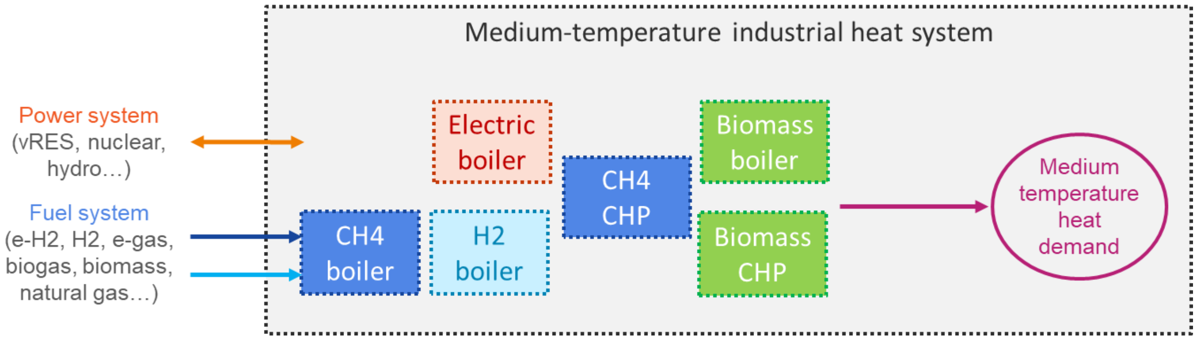

Figure 4-5: Industrial heat system - medium temperature heat

[20] (Eurelectric, 2018), (Navigant, 2019), (Poyry, 2018), (McKinsey, 2017), (Material Economics, 2019), (Energy Transition Commission, 2018), (Fraunhofer ISI, 2019), (Fraunhofer ISI, 2019), (Industrial Value Chain, 2018), (International Energy Agency, 2017)

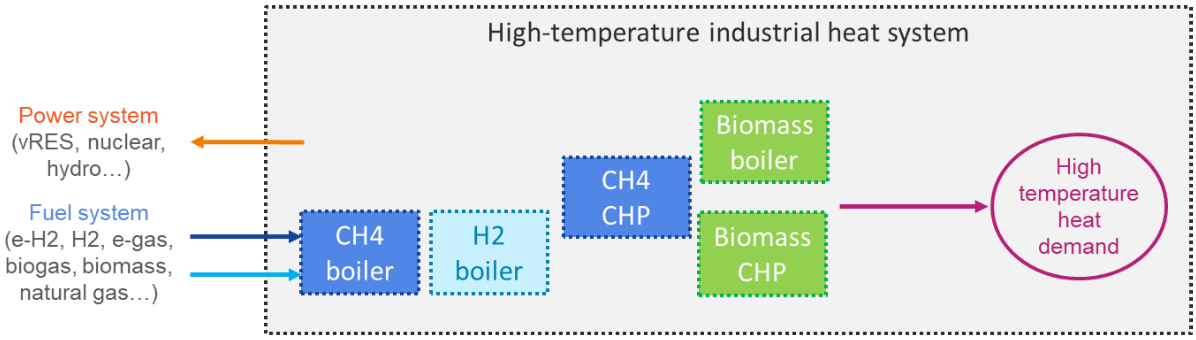

Figure 4-6: Industrial heat system - high temperature heat

Among the available technology options, literature review has found that industrial heat pumps were eligible for low temperature heat only, whereas electric boilers can provide both low and medium temperature heat. At high temperature levels, furnace heat is provided by gas or biofuel burners.

In order to thoroughly model the industrial heat coupling with the power sector, relevant technologies can either be represented as heat-only boilers or CHP technologies. Cogeneration has a role in a limited-resources scenario as it brings in energy savings through their higher efficiencies.

In line with generic assumptions of climate-neutral scenarios, thermal-based heat production technologies can be equipped with CCS. In this case, these units have higher capital costs and slightly reduced efficiencies.

The set of technologies included in the modelling scope is described in Table 5 and Table 6, along with their main technoeconomic parameters.

They feature the following parameters: a heat generation capacity, an availability timeseries, variable consumption costs, and a conversion efficiency that links proportionally fuel consumption (either electricity, gas, hydrogen or biomass) with heat generation. The fuel CO2 content is accounted for when relevant. CHP technologies feature an additional conversion efficiency linking fuel consumption and electricity generation. In addition, a minimum load timeseries and gradients (up and down) can be defined. When the simulation includes the optimal sizing of investments, the capacity parameter is transformed into lower and upper capacity bounds along with associated capacity costs (CAPEX and Fixed Operation Costs). In such a case, both the boiler (or CHP) sizing and operation are optimized.

Technoeconomic parameters are derived from (E3Modelling, Ecofys, Tractebel, 2018) and (JRC, 2017). If the cost of CCS-equipped technologies is not available in these sources, it is estimated considering a capacity cost increase and an efficiency decrease induced by CCS installation, and calibrated on technologies for which data was available both for the regular version and its CCS-equipped counterpart.

	Overnight investment cost (€/kWth)	Yearly fixed O&M costs (in % of overnight CAPEX)	Efficiency (HHV)	Lifetime
Heat pumps	540	0.5%	410%	25
Electric boiler	333	1.5%	100%	25
Biomass boiler	807	0.5%	90%	25
Gas boiler	124	1%	98%	25
Gas boiler with CCS	480	2%	76%	25
Hydrogen boiler	149	1%	98%	25

Table 5: Techno-economic parameters for heat supply technologies (excluding CHPs)[21]

	Overnight investment cost (€/kWe)	Yearly fixed O&M costs (in % of overnight CAPEX)	Thermal efficiency	Electric efficiency	Lifetime
Gas CHP	810	1%	52%	33%	35
Gas CHP + CCS	1640	2%	33%	33%	35
Biomass CHP	3000	1%	66%	27%	30

Table 6: Techno-economic parameters for CHP technologies[22]

Industrial heat demand

In addition to the considerations on temperature levels, the literature review has shown that all industrial heat uses cannot be substituted with other fuels, either for operational, chemical, or technical reasons:

- In some industries, heat delivery is strongly linked to the consecutive operations of several processes within a single plant. For instance, flue gases from an upstream process may be used to provide heat downstream. In such a case, substituting the energy carrier of the upstream process may remove or change the physical characteristics of the flue gases and consequently the heat supply of the downstream process.

- Industrial processes can chemically rely on the energy vector. In blast furnaces for instance, coke is both used to supply heat and reduce the iron oxides, preventing a switch to another fuel.

- Eventually, some processes rely on very specific technologies, hampering the use of another fuel that would be incompatible. That is the case for secondary iron, which is mostly melted in electric arc furnaces that run exclusively on electricity.

Building on the literature review, the scope of the substitutable heat mix is determined for each scenario according to the following methodology, displayed in Figure 4-7:

[21] Technoeconomic parameters are derived from (E3Modelling, Ecofys, Tractebel, 2018) and (JRC, 2017)

[22] Technoeconomic parameters are derived from (E3Modelling, Ecofys, Tractebel, 2018) and (JRC, 2017)

1. Industrial processes are classified as substitutable or non-substitutable heat demand

2. A temperature level is assigned to each substitutable process

3. The scenario-specific industrial heat demand volumes, provided at the process level[23], are then distinguished between substitutable and non-substitutable end-uses and assigned a temperature level, which leads to one annual, substitutable heat demand per temperature level and Member State.

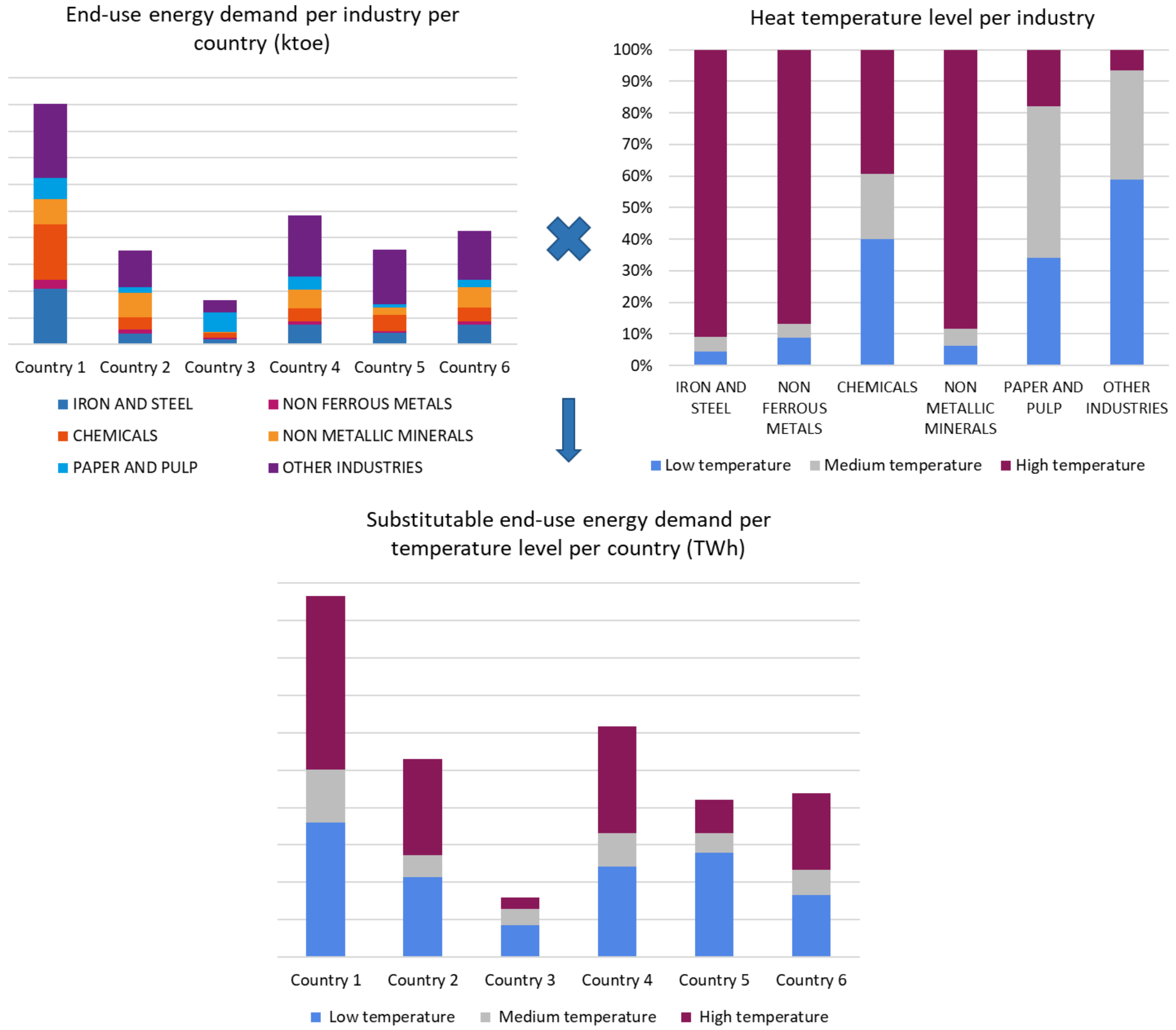

Figure 4-7: Methodology for the integration of industrial heat demand in the METIS model

This process, once applied to the European industry, results in annual heat demands per Member State per temperature level. Hourly industrial heat demand profiles, inspired by the 2015 electricity demand profile of the French industry sector[24], are then rescaled to match annual demands.

Figure 4-8 illustrates a typical result generated by the heat supply mix optimisation. The graph provides a year-long overview of the hourly dispatch of the individual heat

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[23] Data derived from the LTS 1.5TECH scenario.

[24] As published by the French TSO RTE (RTE, 2018)

generation assets (stacked chart) to meet the hourly heat demand (red line). The zoom of Figure 4-8 highlights the use of the optimised peak generation capacities (in the given case gas and hydrogen boilers).

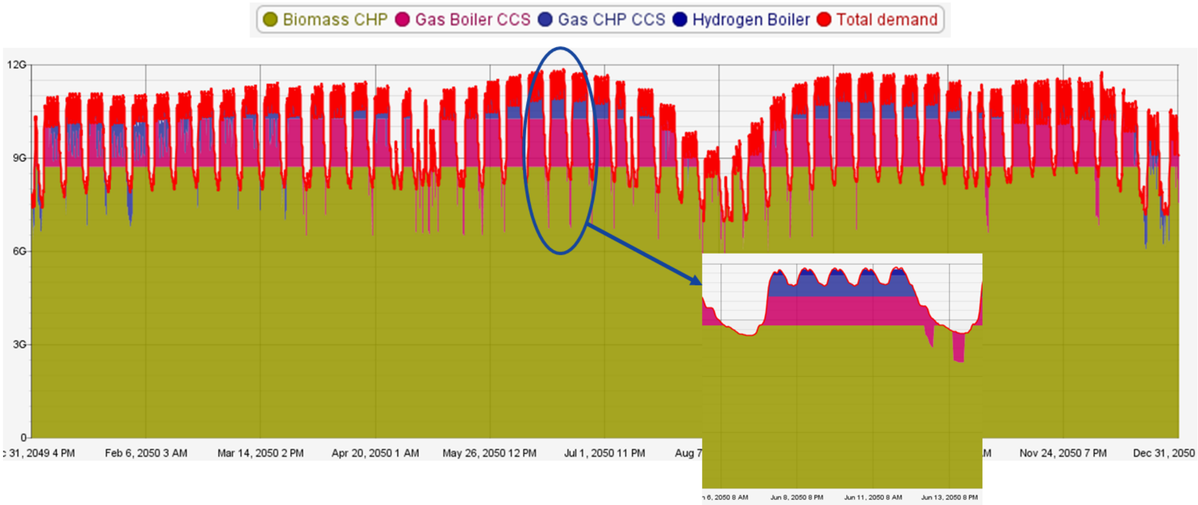

Figure 4-8: High-temperature heat demand and supply profiles

5 REPRESENTATION OF CONSTRAINED BIOGENIC RESOURCES

A climate neutral energy system may make use of biogenic resources (biomass, biogas, biomethane) for dispatchable power plants to balance variable renewable electricity and align with demand patterns, but also to generate heat. As storable commodities, bioresources can supply energy when flexibility is needed or where electrification is too expensive or infeasible. Yet, bioresources are subject to limited potentials.

The METIS energy system integration module considers two types of bioresources, namely (solid) biomass, dedicated to electricity or heat production, and biogas/biomethane, which can be used on-site or upgraded and injected in the gas network. In order to fully account for the constraints on the energy system, each bioresource supply features a limited annual potential, which must not be exceeded.

This constraint can either be set at the system level or at the country level[25]. In Study S6, the following set of constraints was defined:

- As a local resource, biomass potential is defined at the country level. It assumes that there is no trade of biomass resources between countries.

- Given the extended European gas network, the biogas potential is defined at the system level. A single constraint is set, over the sum of biomethane supplies in all the countries. This model enables to consider cross-border exchange of biomethane without explicitly representing the gas network in the METIS tool, hence reducing the numerical complexity of the simulation.

The model considers the physical lifecycle emissions of the resources. Therefore, each unit of biogas used on-site or injected in the gas network implies a "CO2 consumption", representing the carbon captured over the growing phase of the vegetable. On the opposite, the combustion of gas – whatever its origin, hence including biomethane – emits CO2 in the atmosphere. Therefore, biogas lifecycle emissions are actually net-zero overall. If combustion is combined with a CCS process (see Section 6.2), only a share of the CO2 captured during the growing phase is released in the atmosphere, and the process contributes to negative emissions (typically referred to as BECCS, bioenergy plus CCS).

[25] Biogas/biomethane imports from outside the EU were not considered.

6 POWER SYSTEM FLEXIBILITY PROVISION

Significant work on the modelling of flexibility provision has been done in the framework of the first METIS project (interconnectors, demand-side response, voluntary load curtailment, etc.). In order to better reflect operating constraints and flexibility needs in 2050, METIS 2 carries additional work on the modelling of hydro reservoirs and thermal power plants featuring carbon capture and storage.

6.1 HYDRO POWER AND INTER-SEASONAL RESERVOIR MANAGEMENT

In, the METIS power system module, hydro power generation is divided into three categories of assets that are modelled separately:

- **Run-of-river power plants** are represented as uncontrollable (non-dispatchable) generation assets, which means that their generation at all times is determined by an hourly load factor time series.

- **Hydro-reservoir** represents hydraulic dams which have a storage capacity, a natural inflow and extra constraints due to long-term storage management, and an optional pumping capacity

- **Pure pumped hydro storage** can be modelled as storage asset, with an overall efficiency of 81%[26].

In particular, hydro reservoir assets have a limited energy volume that can be injected in the network which depends on the total water inflow over the year. Indeed, hydro reservoir assets cannot constantly generate power at full capacity and have to store part of the inflow in the reservoir to produce electricity during the most demanding periods.

Such a prospective operational management, applied to hydro reservoir assets at different time scales – from weekly to inter-seasonal - is enforced in METIS by means of a rolling optimization horizon[27]. In the METIS power system module, a guide curve defines, on a weekly basis, the minimal allowed storage level, preventing the reservoirs to fully empty themselves at each step of the rolling optimization. Yet, even if this solution is a first step in accounting both for mid-term water management (by satisfying the weekly guide curve) and short-term management (through the hourly optimization), it can lead to some unrealistic behaviour of hydro reservoir assets.

Indeed, enforcing a minimum storage level every week does not leave enough flexibility for the system to adapt to specific situations. For instance, extreme weather conditions on some climatic years could reduce water inflows for several weeks in a row, preventing the storage levels to follow the designed guide curve. On the power system side, a high winter demand resulting from particularly cold weeks would benefit from additional hydro generation, and on the contrary exceptionally high storage levels should be allowed in case of high vRES generation, leading to potential surpluses.

For that purpose, the hydro-reservoir model has been upgraded, and used in METIS 2 Study S3[28].

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[26] (Artelys, 2017)

[27] (Artelys, 2017)

[28] (Engie Impact, Artelys, 2022)

6.1.1 INTER-SEASONAL STORAGE MODEL

The management of inter-seasonal storage based solely on a weekly minimum storage level constraint is not necessarily cost-efficient. In order to further minimize the system costs, yet still accounting for the realistic lack of visibility over more than a few weeks in hydro management, the hard constraint on storage levels has been transformed into a soft constraint, which allows the storage levels to deviate from the guide curve with penalty payments for reaching levels below the guide curve and gains when going above.

These penalties and gains are calculated at the end of the tactical horizon only (see Figure 6-1), allowing an unconstrained hourly water management over the simulation but integrating exogenously a measure of water value at the end of the horizon. In case of extreme weather[29] leading to high power demand or high vRES surpluses, the storage levels may deviate from the guide curve at the end of the horizon, depending on the balance between benefits brought to the system and the estimated value of water deficit/surplus in comparison to the guide curve.

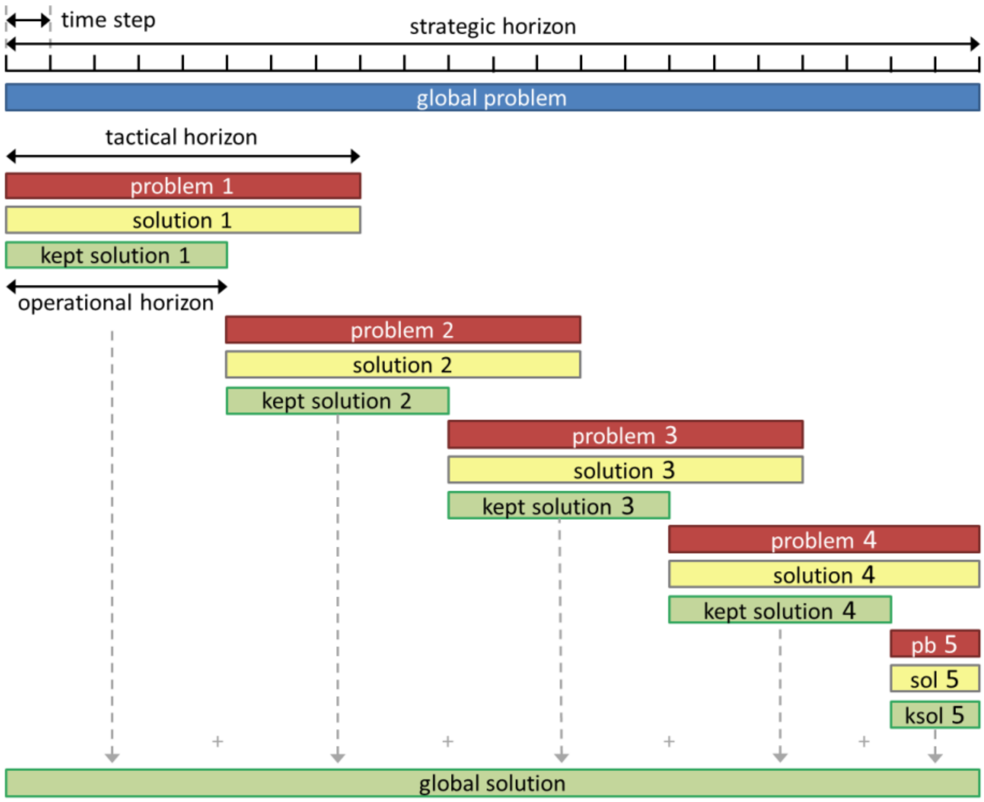

Figure 6-1: Optimisation process used to simulate METIS models. Source: (Artelys, 2017)[30]

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[29] Reflected by test case-specific inflow timeseries, representing weather fluctuations

[30] The simulation typically optimises the production plan with a yearly horizon and an hourly resolution. The simulation of the full year at once (frontal simulation) can require important computation resources and time, especially when the spatial granularity increases. Alternatively, the user can decide to solve the optimisation problem with a **rolling horizon** approach. The solution for the full horizon is obtained by solving smaller problems. Three horizons are defined:

- The strategic horizon corresponding to the duration of the full problem

The following parameters are considered:

- A storage capacity S_{max} which represents the maximum energy volume that can be stored,
- A guide curve time series $guideCurve_t$, which represents the expected storage level evolution over the year, relatively to the storage capacity,
- C^+ and C^-, which are respectively the gain and penalty for deviating from the guide curve (≥ 0)

The following variables are considered:

- A storage level time series $storageLevel_t$, which represents the total stored volume at each timestep,
- Slack variables:
  - δ_t^+, the positive part of the difference between the storage level and the guide curve (≥ 0),
  - δ_t^-, the positive part of the difference between the guide curve and the storage level (≥ 0)

At each iteration over the rolling horizon, a simulation is performed between t_1 and $t_2 = t_1 + tacticalHorizon$ (if no greater than the strategic horizon). The following cost is added to the objective:

$$storageCosts = C^- \cdot \delta_{t_2}^- - C^+ \cdot \delta_{t_2}^+$$

And the following constraint is added to the model in order to define the slack variables:

$$\delta_t^+ - \delta_t^- = storageLevel_t - guideCurve_t$$

The $storageCosts$ are added to the objective function to ensure that actual storage levels do not deviate from the guide curve (at the end of the horizon) unless it brings enough benefits to the system. However, they do not represent actual physical costs, therefore they are not counted as such in the economic KPIs. Only the final rolling horizon iteration captures the actual difference between total annual inflows and total water spilled over the year[31]: this cost is integrated in the KPIs.

- The tactical horizon corresponding to the sub-problem horizon
- The operational horizon corresponding to the interval for which solutions are final

The procedure consists in solving successively simulations with a defined tactical horizon. The horizon of the solutions kept after each problem solved is defined by the operational horizon. At each iteration, the assets' initial state is inherited from their final state at the end of the previous operational horizon

[31] As the guide curve has the same start and end points, the difference between the final storage level and the guide curve captures the difference between initial and final storage levels, i.e. annual inflows and total generation.

The guide curves are either constructed as the average of historical storage levels over the 2015-2019 period[32], or designed to ensure efficient water management in a high-RES scenario[33].

6.1.2 Penalty calibration and model validation

Penalties and gains should be calibrated to ensure an efficient measure of social costs incurred by breaking the soft constraint and deviating from the guide curve. Overall, the hydro reservoir asset should:

- Allow higher storage levels when renewables are marginal on electricity markets (and even pump water if a pumping capacity is available)

- Allow lower storage levels when peak generation capacities represent the marginal power generation unit on electricity markets

To this end, the gain value should be slightly higher than renewable electricity marginal cost, and the penalty should be set between CCGTs and OCGTs marginal costs. In a 2030 system, a gain around 2 €/MWh could be associated with a penalty around 90 €/MWh, while a 2050 energy system featuring high carbon price would rather see a penalty around 200 €/MWh. Such calibration enables to capture renewable surpluses and avoid expensive electricity generation a few dozen hours over the year.

Figure 6-2 shows that water management features more flexibility when modelled with a soft constraint rather than with a hard constraint, along with an overall evolution that still follows the guide curve over the year.

When the optimisation is performed over an entire year (i.e. all the horizons are equal to the strategic horizon, i.e. 1 year), perfect foresight would enable water management to anticipate events in the long-term future. Therefore, in addition to the final storage level penalty (as for the rolling horizon methodology), a weekly storage level soft constraint is considered. Each week, storage level should be higher than the guide curve, otherwise storage would pay a penalty proportional to the violation of the guide curve. This additional soft constraint, also based on the guide curve, constrains the storage evolution over the year and limits the perfect foresight.

[32] ENTSO-E Transparency Platform

[33] (Engie Impact, Artelys, 2022)

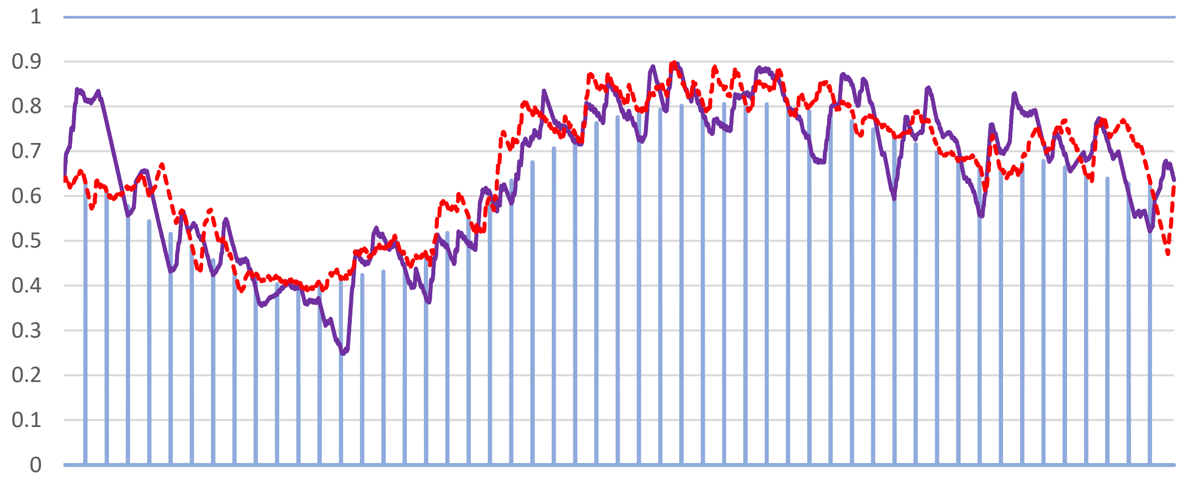

Figure 6-2: Illustrative inter-seasonal storage management replicated in METIS -
Dashed red: management under minimum storage constraint -
Purple: management under soft constraint, associated (penalty, gain)=(100, 2)
Blue: Guide curve
Storage capacity normalised to 1

6.2 THERMAL GENERATION FEATURING CARBON CAPTURE AND STORAGE

In order to better account for the possibility to alleviate CO2 emissions over the combustion process, the METIS energy system integration module includes CCS-equipped thermal electricity generation plants. The model is able to commission either gas-fired power plants or their CCS-equipped counterparts.

Technoeconomic parameters of gas-fired plants are displayed Table 7. They are derived from the ASSET Study[34]. CCS-equipped plants feature a 90% CO2-emissions reduction[35] rate compared to their regular counterpart.

	Overnight investment cost (€/kW)	Yearly fixed O&M costs (in % of overnight CAPEX)	Efficiency	Lifetime (years)
OCGT	600	3%	40%	25
CCGT	750	2%	63%	30
CCGT with CCS	1500	2%	49%	30

Table 7: Technoeconomic parameters of gas-fired power plants

[34] (E3Modelling, Ecofys, Tractebel, 2018)

[35] Based on (Brandl, Bui, Hallett, & Dowell, 2021)

7 SCENARIOS USED IN THE METIS MODEL UPDATE

The following scenarios have been integrated into METIS using the level of detail and the modelling features of the METIS energy system integration module:

- The EU Long Term Strategy Baseline scenario
- The EU Long Term Strategy P2X scenario
- The EU Long Term Strategy 1.5TECH scenario

The METIS scenarios contain the information for all EU Member States, plus Switzerland, Bosnia-Herzegovina, Serbia, North Macedonia, Montenegro, Norway and United-Kingdom. The general integration of the EC LTS scenario data into METIS is described in the METIS 2 Technical Note T1.[36]

[36] (Artelys, 2021)

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