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EOLES_mv model description

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0. EOLES_mv model

The EOLES family of models performs simultaneous optimization of the investment and operation of the energy system in order to minimize the total cost while satisfying energy demand. The "mv" in EOLES_mv stands for multi-vector and this model minimizes the annualized energy generation, conversion and storage costs, including the cost of connection to the grid. EOLES_mv considers all the major energy sectors (residential and tertiary buildings, industry, transport and agriculture) in an integrated manner, enabling sector-coupling.

The EOLES_mv model includes seven power generation technologies: floating and monopile offshore wind power, onshore wind power, photovoltaic solar power (PV), run-of-river and lake-generated hydro-electricity and nuclear power (EPR, i.e. third generation European Pressurized Water Reactors) and three gas production technologies: natural gas, methanization from anaerobic digestion and pyro-gasification of solid biomass. Sector-coupling is enabled by vector-change (energy conversion) technologies: open-cycle gas turbines (OCGT), combined-cycle gas turbines (CCGT) and CCGTs equipped with post-combustion carbon capture and storage (CCS) technologies are used to convert gas to electricity. Vector-change from electricity to gas is enabled by electrolysis (power to hydrogen to inject into the gas network with a volume share limit) and methanation (hydrogen production from electrolysis of water and use of the Sabatier reaction between the hydrogen thus produced and green CO_2 to produce synthetic methane) as power-to-gas options. Similarly, centralized and decentralized boilers are used to produce heat from gas and centralized and individual heat pumps and resistive heat production technologies are used to produce heat from electricity. The model includes two electricity storage technologies (Li-Ion batteries and pumped hydro storage), the existing gas network as the gas storage option and two heat storage technologies (centralized and decentralized hot water tanks). This model also allows demand for transport to be met with an endogenous choice between electric vehicles and internal combustion engine vehicles, for four main transport categories: light vehicles, heavy vehicles, buses and trains. The interaction of different energy end-use demands, supply side, storage and energy carriers are presented in Figure 5.1.

The EOLES_mv model is based on representative technologies chosen from groups of technologies with similar technical and economic behavior. For instance, only two engine types are considered in the transport sector: gas-fueled internal combustion engine (ICE) vehicles and battery electric vehicles (BEV). Other transport options include liquid-fueled ICE vehicles and hydrogen-fueled fuel cell electric vehicles but since they have similar

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economic and technical behavior to gas-fueled ICE vehicles and BEVs respectively, they have been excluded in order to maintain computational tractability.

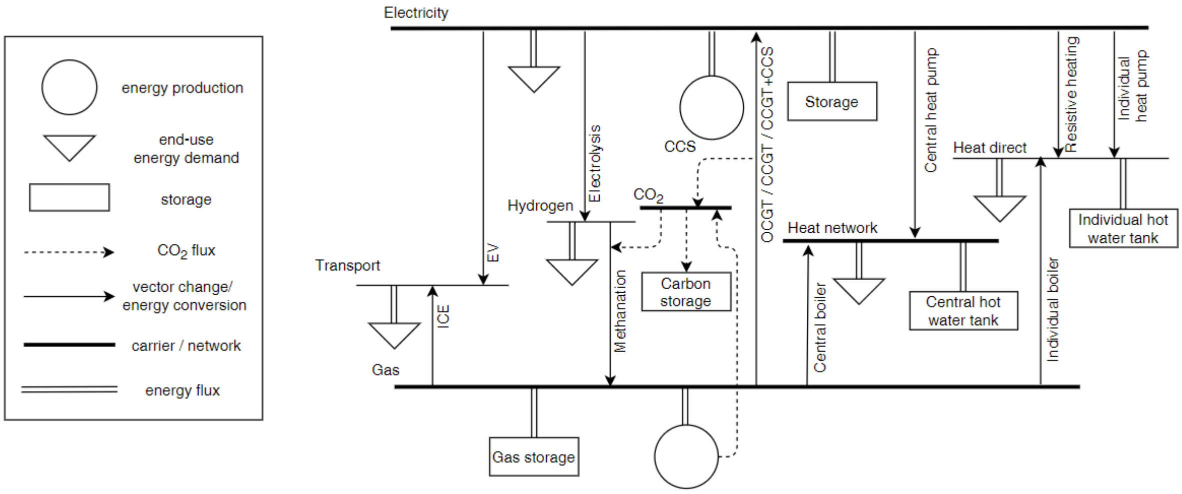

Figure 1 Schematic diagram of the EOLES_mv model; the figure on the right shows the interactions between energy supply, demand, storage and carriers by energy flux and CO2 exchanges. The box on the left provides the key to the shapes. The two energy supply technologies are electricity and gas production, each connected to its own network.

EOLES_mv is one of the EOLES models, therefore all the simplifying assumptions for previous EOLES models (EOLES_elecRES and EOLES_elec) hold for EOLES_mv as well: greenfield optimization with static end-point but not a dynamic trajectory and considering a country as a single node with aggregated weather data. This model considers a wholesale single-buyer market with perfect competition and full information assumptions, and the energy demand in EOLES_mv is inelastic.

This model uses only linear optimization: non-linear constraints might improve accuracy, especially when studying unit commitment, however they entail significant increase in computation time. Palmintier (2014) has shown that linear programming provides an interesting trade-off, with little impact on cost, CO_2 emissions and investment estimations, but speeds up processing by up to 1,500 times. Similarly, according to Cebulla et al (2017), in modelling thermal power plants, mixed-integer linear programming can capture the techno-economic characteristics more precisely compared to linear programming (LP), while LP has a superior computational performance. Linear programming merit order dispatch underestimates the storage demand compared to mixed-integer linear programming (MILP)[3], but this divergence is less visible for high renewable share in power system.

The model is written in GAMS and solved using the CPLEX solver. The GAMS scripts and the input data are available on Github.[4]

The remainder of this document presents the used input parameters and resulting variables, main equations of the model and suggested values for France for 2050. Sections 1 and 2 represent sets, parameters and variables of EOLES_mv model respectively. The

[3] It can be considered as mixed-integer unit-commitment with economic dispatch.
[4] https://github.com/BehrangShirizadeh/EOLES_mv

equations are presented in Section 3, and the suggested input parameters are presented in Section 4.

1. Sets and parameters

Table 1 presents the sets and indices of the EOLES_mv model and Table 2 the parameters. Throughout the paper, every energy unit (e.g. MWh) or capacity unit (e.g. MW) is expressed in useful form. For instance, some energy is converted from gas to electricity by OCGT. The input energy in MWh is in the gas carrier, therefore the unit is MWh_{th} and conversion efficiency by OCGT is 45%. The output energy is in MWh_e equivalent to the value in MWh_{th} multiplied by 0.45.

Table 1 Sets and indices of the EOLES_mv model

Index	Set	Description
h	∈ H	**Hour:** the number of hours in a year, from 0 to 8759
d	∈ D	**Day:** The number of days in a year, from 1 to 365
w	∈ W	**Week:** The number of weeks in a year, from 1 to 52 (the 52^{nd} week accounts for 10 days)
m	∈ M	**Month:** the twelve months, from January to December
tec	∈ TEC	**Technologies:** The set of all energy supply, conversion, storage and non-existing carrier technologies (floating offshore, monopile offshore, onshore, PV, river, lake, nuclear, natural gas, methanization, pyro-gasification, OCGT, CCGT, CCGT with CCS, electrolysis, methanation, heat network, resistive heating, electric heat pump, gas heat pump, central boiler, decentralized boiler, heavy EV, light EV, EV bus, train, heavy ICE, light ICE, ICE bus, PHS, battery, gas storage, individual thermal energy storage -ITES- and central thermal energy storage -CTES)
gen	∈ GEN ⊆ TEC	**Generation:** Energy supply technologies (floating offshore, monopile offshore, onshore, PV, river, lake, nuclear, natural gas, methanization and pyro-gasification)
$elec$	∈ ELEC ⊆ TEC	**Electricity:** The technologies providing electricity by supply, conversion or storage (floating offshore, monopile offshore, onshore, PV, river, lake, nuclear, OCGT, CCGT, CCGT with CCS, PHS and battery)
gas	∈ GAS ⊆ TEC	**Gas:** The technologies providing gas by supply, conversion or storage (natural gas, methanization, pyro-gasification, electrolysis, methanation and gas storage)
$heat$	∈ HEAT ⊆ TEC	**Heat:** The technologies providing heat by conversion and storage (heat network, resistive heating, electric heat pump, gas heat pump, central boiler, decentralized boiler, individual thermal energy storage and central thermal energy storage)
$transport$	∈ TRANSPORT ⊆ TEC	**Transport:** The technologies that meet different types of transport demand (heavy EV, light EV, EV bus, train, heavy ICE, light ICE and ICE bus)
gen_{elec}	∈ ELECGEN ⊆ ELEC	**Electricity supply:** The technologies generating electricity (floating offshore, monopile offshore, onshore, PV, river, lake and nuclear)
gen_{gas}	∈ GASGEN ⊆ GAS	**Gas supply:** Technologies supplying gas (natural gas, methanization and pyro-gasification)

$biogas_{gas}$	∈ BIOGAS ⊆ GAS	**Renewable gas:** biogas supply technologies (methanization and pyro-gasification)
vre	∈ VRE ⊆ ELEC	**VRE:** variable renewable electricity generation technologies (offshore, onshore, PV and run-of-river)
str	∈ STR ⊆ TEC	**Storage:** energy storage technologies (PHS, battery, gas storage, individual thermal energy storage and central thermal energy storage)
str_{elec}	∈ STRELEC ⊆ ELEC	**Electric storage:** technologies providing storage for electricity (battery and PHS)
str_{gas}	∈ STRGAS ⊆ GAS	**Gas storage:** technologies providing storage for gas (gas storage)
str_{heat}	∈ STRHEAT ⊆ HEAT	**Heat storage:** technologies providing storage for heat (ITES and CTES)
$conv$	∈ CONV ⊆ TEC	**Conversion:** energy vector-change technologies (OCGT, CCGT, CCGT with CCS, electrolysis, methanation, resistive heating, electric heat pump, gas heat pump, central boiler and decentralized boiler)
$conv_{elec}$	∈ CONVELEC ⊆ TEC	**Conversion from electricity:** energy vector-change technologies from electricity to other vectors (electrolysis, methanation, resistive heating and electric heat pump)
$conv_{gas}$	∈ CONGAS ⊆ TEC	**Conversion from gas:** energy vector-change technologies from gas to other vectors (OCGT, CCGT, CCGT with CCS, gas heat pump, centralized boiler and decentralized boiler)
$central$	∈ CENTRAL ⊆ HEAT	**Central heating:** heating technologies needing heat network (electric heat pump, gas heat pump and centralized boilers)
$vector_t$	∈ TVECTOR	**Transport vector:** two different engine types for transport sector (EV and ICE)
cat_t	∈ TCAT	**Transport category:** four categories of transport demand (heavy, light, bus and train)
$ev_{transport}$	∈ EV ⊆ TRANSPORT	**Electric transport:** the electric transport technologies (heavy EV, light EV, EV bus and train)
$ice_{transport}$	∈ ICE ⊆ TRANSPORT	**Gas transport:** the ICE transport technologies using gas as fuel (heavy ICE, light ICE and ICE bus)
frr	∈ FRR ⊆ TEC	**Frequency restauration reserves:** Technologies contributing to secondary reserves requirements (lake, PHS, battery, OCGT, CCGT, CCGT with CCS and nuclear)
co_2	∈ CO2	**Social cost of carbon scenario:** The scenarios are 1, 2, 3, 4, 5 and 6

Table 2 Parameters of the EOLES_mv model

Parameter	Unit	Description
day_h	[-]	A parameter to show which day each hour is in
$week_h$	[-]	A parameter to show which week each hour is in
$month_h$	[-]	A parameter to show which month each hour is in
$cf_{vre,h}$	[-]	Hourly production profiles of variable renewable energies
$profile_h^{transport}$	[-]	Hourly charging profile of each transport technology
$demand_{heat,h}$	$[GW_{th}]$	Hourly heat demand profile
$demand_{hydrogen,h}$	$[GW_{th}]$	Hourly hydrogen demand profile (for industry)
$demand_{elec,h}$	$[GW_e]$	Hourly electricity demand profile

$demand_h^{heavy}$	$[Gkm.vehicle]$	Hourly transport demand for heavy vehicles
$demand_h^{light}$	$[Gkm.vehicle]$	Hourly transport demand for light vehicles
$demand_h^{bus}$	$[Gkm.vehicle]$	Hourly transport demand for buses
$demand_h^{train}$	$[GWh_e]$	Hourly transport demand for trains (flat)
$lake_m$	$[GWh_e]$	Monthly extractable energy from lakes
ε_{vre}	[-]	Frequency restoration requirement because of forecast errors on the production of each variable renewable energy
q_{tec}^{ex}	$[GW_e]$	Existing installed capacity by each hydroelectric technology
$annuity_{tec}$	[M€/GW/year]	Annualized capital cost of each technology
$annuity_{str}^{en}$	[M€/GWh/year]	Annualized capital cost of energy volume for storage technologies
$annuity_{transport}^{vol}$	[M€/GWh/year]	Annualized capital cost of energy reservoir volume of transport technology
$fO\&M_{tec}$	[M€/GW /year]	Annualized fixed operation and maintenance cost
$vO\&M_{tec}$	[M€/GWh]	Variable operation and maintenance cost of each technology
η_{str}^{in}	[-]	Charging efficiency of storage technologies
η_{str}^{out}	[-]	Discharging efficiency of storage technologies
η_{conv}	[-]	Conversion efficiency for vector change technologies
$\eta_{cat_t}^{vector_t}$	$[Gkm.vehicle$ $/kWh]$	Transport efficiency of each transport technology
q^{pump}	$[GW_e]$	Pumping capacity for Pumped hydro storage
e_{PHS}^{max}	$[GWh_e]$	Maximum energy volume that can be stored in PHS reservoirs
g_{biogas}^{max}	$[TWh_{th}]$	Maximum yearly energy that can be generated from renewable gas supply technologies
$\delta_{uncertainty}^{load}$	[-]	Uncertainty coefficient for hourly electricity demand
$\delta_{variation}^{load}$	[-]	Load variation factor
r_{nuc}^{up}	[-]	Maximal ramping up rate of nuclear power
r_{nuc}^{down}	[-]	Maximal ramping down rate of nuclear power
cf_{nuc}	[-]	The maximal annual capacity factor for nuclear power
cf_{ocgt}	[-]	The maximal annuity capacity factor for OCGT plant
cf_{ccgt}	[-]	The maximal annual capacity factor for CCGT plant

$cf_{ccgt-ccs}$	[-]	The maximal annual capacity factor for CCGT with CCS plants
e_{tec}	$[tCO_2/GWh]$	Emission rate of each technology
scc_{co_2}	$[€/tCO_2]$	Social cost of carbon for each SCC scenario
$\varphi_{CO_2}^{max}$	$[MtCO_2/year]$	The maximal carbon dioxide that can be stored annually
$\gamma_{methanization}^{CO_2}$	[-]	The green CO_2 available as a byproduct of methanization for methanation
$\tau^{hydrogen}$	[-]	The maximal penetration rate of hydrogen in the gas network

2. Variables

The variables resulting from the optimization are presented in Table 3.

Table 3 Variables of EOLES_mv model

Variable	***Unit***	***Description***
$G_{tec,h}$	GWh_e	Hourly electricity generation by technology
Q_{tec}	GW_e	Installed capacity by technology
$STORAGE_{str,h}$	GWh_e	Hourly electricity entering each storage technology (inflow)
$STORED_{str,h}$	GWh_e	Hourly energy stored in each technology (stock)
S_{str}	GW_e	Installed charging capacity by storage technology
$VOLUME_{str}$	GWh_e	Energy capacity by storage technology
$RSV_{frr,h}$	GW_e	Hourly upward frequency restoration requirement to manage the variability of renewable energies and demand uncertainties
$COST$	b€	Total power system cost annualized (minus the fixed cost of already installed capacities). This is the objective function to be minimized.

3. Equations

3.1. Objective function

The objective function is similar to the one in chapter three where the social cost of carbon is included (Equation 1):

$$COST = \left(\sum_{tec}[(Q_{tec} - q_{tec}^{ex}) \times annuity_{tec}] + \sum_{str}(VOLUME_{str} \times annuity_{str}^{en}) + \sum_{tec}(Q_{tec} \times fO\&M_{tec}) + \sum_{tec}\sum_{h}(G_{tec,h} \times (vO\&M_{tec} + e_{tec}SCC_{CO_2}))\right)/1000 \quad (1)$$

where Q_{tec} represents the production capacities, q_{tec}^{ex} represents the existing capacity (notably for hydro-electricity technologies with long lifetime), $VOLUME_{str}$ is the energy storage capacity in GWh, S_{str} is the storage capacity in GW, $annuity$ is the annualized investment cost, $fO\&M$ and $vO\&M$ respectively represents fixed and variable operation and maintenance costs, $G_{tec,h}$ is the hourly generation of each technology, e_{tec} is the specific emission of each technology in tCO_2/GWh of power production and SCC_{CO_2} is the social cost of carbon in €/tCO_2.

3.2. Adequacy equations

Energy demand must be met for each hour. If energy production exceeds energy demand, the excess energy can be either sent to storage units or curtailed (Equations 2, 3, 4, 5a-d and 6).

$$\sum_{elec} G_{elec,h} \geq demand_{elec,h} + \sum_{str_{elec}} STORAGE_{str_{elec},h} + \sum_{conv_{elec}} CONVERT_{conv_{elec},h} + \sum_{ev} CHARGE_{ev,h} \quad (2)$$

$$\sum_{gas} G_{gas,h} \geq \sum_{str_{gas}} STORAGE_{str_{gas},h} + \sum_{conv_{gas}} CONVERT_{conv_{gas},h} + \sum_{ice} CHARGE_{ice,h} + demand_{hydrogen,h} \quad (3)$$

$$\sum_{heat} G_{heat,h} \geq demand_{heat,h} + \sum_{str_{heat}} STORAGE_{str_{heat},h} \quad (4)$$

$$G_{heavy_t,h} \times \eta_{heavy_t}^{vector_t} = demand_{transport,h}^{heavy_t} \quad (5a)$$

$$G_{light_t,h} \times \eta_{light_t}^{vector_t} = demand_{transport,h}^{light_t} \quad (5b)$$

$$G_{bus,h} \times \eta_{bus_t}^{vector_t} = demand_{transport,h}^{bus_t} \quad (5c)$$

$$G_{train_t,h} \times \eta_{train_t}^{ev_t} = demand_{transport,h}^{train_t} \quad (5d)$$

$$G_{electrolysis,h} \geq demand_{hydrogen,h} \quad (6)$$

Where $G_{elec,h}$, $G_{gas,h}$, $G_{heat,h}$ is the energy produced by electricity, gas and heat technologies at hour *h* and $STORAGE_{str_{elec},h}$, $STORAGE_{str_{gas},h}$, $STORAGE_{str_{heat},h}$ is the energy entering storage electricity, gas and heat storage technologies at hour *h*. $CONVERT_{conv_{elec},h}$ is the energy conversion from electricity to other vectors and $CONVERT_{conv_{gas},h}$ is the energy conversion from gas to other vectors at hour *h* and $CHARGE_{ice,h}$ is the charging of internal combustion engine vehicles and $CHARGE_{ev,h}$ is the charging of electric vehicles at hour *h*. For each transport category the energy demand in vehicle.km should be satisfied either by *ev* or *ice* as transport energy vector options ($vector_t$), and the conversion from the energy in the gas or electricity form to the demand by transport category ($demand_{transport,h}^{heavy_t}$, $demand_{transport,h}^{light_t}$ and $demand_{transport,h}^{bus_t}$) in vehicle.km is done by the vehicle efficiency changing by both the energy vector and the transport category; $\eta_{cat_t}^{vector_t}$. We only consider the electricity to satisfy the trains' demand.

According to Vogl et al. (2018), the coal demand for steel industry can be replaced by hydrogen. Therefore, we define an hourly hydrogen demand for steel industry ($demand_{hydrogen,h}$) which should be satisfied (Equation 6) beside other adequacy equations.

3.3. Variable renewable power production

For each variable renewable energy (VRE) technology, for each hour, the hourly power production is given by the hourly capacity factor profile multiplied by the installed capacity available (Equation 7).

$$G_{vre,h} = Q_{vre} \times cf_{vre,h} \tag{7}$$

Where $G_{vre,h}$ is the energy produced by each VRE resource at hour *h*, Q_{vre} is the installed capacity and $cf_{vre,h}$ is the hourly capacity factor.

3.4. Energy storage

Energy stored by storage option *str* at hour *h+1* is equal to the energy stored at hour *h* plus the difference between the energy entering and leaving the storage option at hour *h*, accounting for charging and discharging efficiencies.

$$SOC_{str,h+1} = SOC_{str,h} + (STORAGE_{str,h} \times \eta_{str}^{in}) - (\frac{G_{str,h}}{\eta_{str}^{out}}) \tag{8}$$

Where $SOC_{str,h}$ is the state of charge of the storage option *str* at hour *h*, while $\eta_{str}^{in} \in [0,1]$ and $\eta_{str}^{out} \in [0,1]$ are the charging and discharging efficiencies.

3.5. Secondary reserve requirements

Three types of operating reserves are defined by ENTSO-E (2013), depending on their activation speed. The fastest reserves are Frequency Containment Reserves (FCRs), which must be able to be on-line within 30 seconds. The second group is made up of Frequency Restoration Reserves (FRRs), in turn divided into two categories: a fast, automatic component (aFRRs), also called 'secondary reserves', with an activation time of no more than 7.5 min; and a slow manual component (mFRRs), or 'tertiary reserves', with an activation time of no more than 15 min. Finally, reserves with a startup-time beyond 15 minutes are classified as Replacement Reserves (RRs).

Each category meets specific system needs. The fast FCRs are useful in the event of a sudden break, like a line fall, to avoid system collapse. FRRs are useful for variations over several minutes, such as a decrease in wind or PV output. Finally, the slow RRs act as a back-up, slowly replacing FCRs or FRRs when the system imbalance lasts more than 15 minutes.

In the model we only consider FRRs, since they are the most heavily impacted by the inclusion of VRE. FRRs can be defined either upwards or downwards, but since the electricity output of VREs can be curtailed, we consider only upward reserves.

The quantity of FRRs required to meet ENTSO-E's guidelines is given by Equation (9). These FRR requirements vary with the variation observed in the production of renewable energies. They also depend on the observed variability in demand and on forecast errors:

$$\sum_{frr} RSV_{frr,h} = \sum_{vre}(\varepsilon_{vre} \times Q_{vre}) + demand_h \times (1 + \delta^{load}_{variation}) \times \delta^{load}_{uncertainty} \quad (9)$$

Where $RSV_{frr,h}$ is the required hourly reserve capacity from each of the reserve-providing technologies (dispatchable technologies) indicated by the subscript *frr;* ε_{vre} is the additional FRR requirement for VRE because of forecast errors, $\delta^{load}_{variation}$ is the load variation factor and $\delta^{load}_{uncertainty}$ is the uncertainty factor in the load because of hourly demand forecast errors.

3.6. Energy-generation-related constraints

The relationship between hourly-generated electricity and installed capacity can be calculated using Equation (10). Since the chosen time slice for the optimization is one hour, the capacity enters the equation directly instead of being multiplied by the time slice value.

$$G_{tec,h} \leq Q_{tec} \quad (10)$$

The installed capacity of all the dispatchable technologies should be more than the electricity generation required of those technologies to meet demand; it should also satisfy the secondary reserve requirements. Installed capacity for dispatchable technologies can therefore be expressed by Equation (11).

$$Q_{frr} \geq G_{frr,h} + RSV_{frr,h} \quad (11)$$

Monthly available energy for the hydroelectricity generated by lakes and reservoirs is defined using monthly lake inflows (Equation 12). This means that energy stored can be used within the month but not across months. This is a parsimonious way of representing the non-energy operating constraints faced by dam operators, as in Perrier (2018).

$$lake_m \geq \sum_{h \in m} G_{lake,h} \quad (12)$$

Where $G_{lake,h}$ is the hourly power production by lakes and reservoirs, and $lake_m$ is the maximum electricity that can be produced from this energy resource in one month.

3.7. Energy conversion

Energy generated by any energy conversion technology should include the conversion efficiency of the conversion technology. Equation (13) relates the energy generation and generation by each conversion technology.

$$G_{conv,h} = \eta^{conv} \times CONVERT_{conv,h} \quad (13)$$

Where η^{conv} is the conversion efficiency of the energy conversion technology $conv$, and $CONVERT_{conv,h}$ is the converted energy by the same conversion technology at hour *h*.

3.8. Charging of transport technologies

Electric vehicles and internal combustion engine vehicles have different charging profiles. Equation (14) applies these charging profiles;

$$CHARGE_{transport,h} = profile_h^{transport} \times Q_{transport} \tag{14}$$

Where $CHARGE_{transport,h}$ is the hourly charging of each transport technology (both EVs and ICEs four all four transport categories), $profile_h^{transport}$ is the predefined hourly charging profile of each of the transport technologies and $Q_{transport}$ is the charging capacity of transport technology $transport$.

EOLES_mv considers an average of one charge per week for each transport technology, and since the energy can be stored in the vehicle during the whole one week, the transport demand that should be satisfied is considered to have a weekly adequacy. The hourly demand of transport in vehicle.km should be satisfied from Equations (5a-d) and the charging profiles should be applied to account for the charging behavior of different transport technologies from Equation (14). Equation (15) is defined to keep both charging and demand constraints above and to let the vehicles choose the day of charging during the week;

$$\sum_{h\in w} CHARGE_{transport,h} = \sum_{h\in w} G_{transport,h} \tag{15}$$

The storage volume of each transport technology accounts for an upper limit for the weekly charge and weekly energy consumption of it. While this storage volume is free of charge for ICE vehicles, electric vehicles' main cost component is this battery storage volume. Therefore, the reservoir size (storage volume) for each transport technology is defined (Equation 16).

$$\sum_{h\in w} CHARGE_{transport,h} \leq RESERVOIR_{transport} \tag{16}$$

Where $RESERVOIR_{transport}$ accounts for the reservoir size of each transport technology (kWh_e for electric vehicles and kWh_{th} for ICE vehicles).

3.9. Inclusion of heat networks

Heat can be produced by two different technology classes: distributed technologies such as resistive heating technology, and centralized technologies such as central boilers. Decentralized heating technologies use electricity or gas from the network and provide heating for the local demand, therefore no heat network is needed. On the other hand, the centralized technologies produce heat in large quantities and distribute it to the points of the demand in different locations, which require a heat network. Equation (17) separates the central heating technologies and define a heat network capacity for the distribution of produced heat:

$$Q_{heat-net} \geq Q_{central} \tag{17}$$

Where $Q_{heat-net}$ is the heat network capacity and $Q_{central}$ is the installed capacity of each central heat production technology in kW_{th}.

Equation (17) allows the heat network to have lower capacity than all the central heating technologies combined, depending on the optimal dispatching of each of them. Another equation is needed to restrict the central heating technologies to pass through the heat network (Equation 18);

$$G_{heat-net,h} = \sum_{central} G_{central,h} \tag{18}$$

Where $G_{heat-net,h}$ is the heat generation passed through heat network and $G_{central,h}$ is the heat generation by each central heating technology at hour h.

3.10. Operational constraints of conversion technologies

For open-cycle and combined-cycle gas turbines, there are some safety- and maintenance-related breaks. Equations (19), (20) and (21) limit the annual power production for each of these plants to their maximum annual capacity factors:

$$\sum_h G_{ocgt,h} \leq Q_{ocgt} \times cf_{ocgt} \times 8760 \tag{19}$$

$$\sum_h G_{ccgt,h} \leq Q_{ccgt} \times cf_{ccgt} \times 8760 \tag{20}$$

$$\sum_h G_{ccgt-ccs,h} \leq Q_{ccgt-ccs} \times cf_{ccgt-ccs} \times 8760 \tag{21}$$

Where cf_{ocgt} and cf_{ccgt} are the capacity factors of OCGT and CCGT power plants.

The hydrogen produced from electrolysis (power-to-gas conversion) is either consumed directly in the industry (therefore we make the assumption of local electrolysis for industrials) or injected to the gas network. Because of different thermochemical properties of hydrogen, it cannot be injected in any rate to the gas network. Equations (22), (23) and (24) limit the hydrogen that can exist in the gas network as a proportion of the overall existing gas in this network both in the storage level and in the distribution/transmission level;

$$G_{electrolysis,h} \leq \tau^{hydrogen} \times SOC_{gastank,h} + demand_{hydrogen,h} \tag{22}$$

$$G_{electrolysis,h} \leq \tau^{hydrogen} \times \sum_{gas} G_{gas,h} + demand_{hydrogen,h} \tag{23}$$

$$\sum_h G_{electrolysis,h} \leq \tau^{hydrogen} \times \sum_{gas \neq gastank,h} G_{gas,h} + \sum_h demand_{hydrogen,h} \tag{24}$$

Where $G_{electrolysis,h}$ is the energy value of hydrogen injected to gas network from electrolysis at hour h, $\tau^{hydrogen}$ is the maximal relative energy share of hydrogen to the overall gas in the gas network which can be different for different countries depending on the capability of gas network in hosting hydrogen. $SOC_{gastank,h}$ is the state of charge of gas storage, which is the energy value of overall existing gas in the gas network and $\sum_{gas} G_{gas,h}$ is the overall gas production at hour h. Equation (22) limits the relative share of hydrogen to other gas options in the storage infrastructures and equation (23) limits the relative share of hydrogen in the gas network. Equation (24) makes sure that the overall hydrogen that is produced is not more than the capacity of the gas network.

3.11. Nuclear-power-related constraints

Addition of nuclear power plants to the model brings three main constraint type equations: ramping up and ramping down rates (because we allow these plants to be used in load-following mode, Loisel et al., 2018) and the annual maximal capacity factor.

Nuclear power plants have limited flexibility, so definitions of hourly ramp-up and ramp-down rates are essential to model them accurately. Equations (25) and (26) limit the power production of nuclear power plants with these ramping constraints:

$$G_{nuc,h+1} + RSV_{nuc,h+1} \leq G_{nuc,h} + r_{nuc}^{up} \times Q_{nuc} \tag{25}$$

$$G_{nuc,h+1} \geq G_{nuc,h}(1 - r_{nuc}^{down}) \tag{26}$$

Where $G_{nuc,h+1}$ is the nuclear power production at hour $h+1$, $G_{nuc,h}$ is the nuclear power production at hour h, $RSV_{nuc,h+1}$ is the reserve capacity provided by nuclear power plants at hour $h+1$ and r_{nuc}^{up} and r_{nuc}^{down} are the ramp-up and ramp-down rates for nuclear power production.

The nuclear power plants' capacity factor should also be limited by safety and maintenance constraints. Equation (27) quantifies this limitation:

$$\sum_h G_{nuc,h} \leq Q_{nuc} \times cf_{nuc} \times 8760 \tag{27}$$

Where cf_{nuc} is the maximum annual capacity factor of nuclear power plants.

3.12. Storage-related constraints

To prevent optimization leading to a very high quantity of stored energy in the first hour represented and a low quantity in the last hour, we add a ***cyclicity*** constraint to ensure the replacement of the consumed stored electricity in every storage option (Equation 28):

$$STORED_{str,0} = STORED_{str,8759} + (STORAGE_{str,8759} \times \eta_{str}^{in}) - (\frac{G_{str,8759}}{\eta_{str}^{out}}) \tag{28}$$

While Equations (8) and (28) define the storage mechanism and constraint in terms of power, we also limit the available volume of energy that can be stored by each storage option (Equation 29):

$$STORED_{str,h} \leq VOLUME_{str} \tag{29}$$

Equation (30) limits the entry of energy into the storage units to the charging capacity of each storage unit. Similarly, we consider a charging capacity lower than or equal to the discharging capacity (mainly to limit the charging capacity of batteries) which means that the charging capacity cannot exceed the discharging capacity.

$$STORED_{str,h} \leq S_{str} \leq Q_{str} \tag{30}$$

3.13. Resource availability related constraints

The maximum installed capacity of each technology is defined in equation (31) where q_{tec}^{max} is this capacity limit:

$$Q_{tec} \leq q_{tec}^{max} \tag{31}$$

Renewable gas production technologies are limited due to land-use and agricultural constraints. Equation (32) limits the annual renewable gas production from each of two renewable gas production technologies; methanization and pyro-gasification of biomass.

$$\sum_{h=0}^{8759} G_{biogas,h} \leq g_{biogas}^{max} \tag{32}$$

Where $G_{biogas,h}$ is the hourly biogas production from each of renewable gas production technologies and g_{biogas}^{max} is the maximal yearly biogas that can be produced from each of renewable gas production technologies, both in energy values.

Methanation consists of the Sabatier reaction of hydrogen produced from electrolysis of water and green CO_2 produced as a by-product of methanization process. Implication of this limit in the overall methane production from methanation process is presented in Equation (33):

$$\sum_{h=0}^{8759} CONVERT_{methanation,h} \leq \sum_{h=0}^{8759} G_{methanization,h} \times \gamma_{methanization}^{CO_2} \tag{33}$$

Where $CONVERT_{methanation,h}$ accounts for the hourly methane produced from power-to-methane (methanation) process, $G_{methanization,h}$ is the hourly biogas production from methanization process and $\gamma_{methanization}^{CO_2}$ is the relative share of carbon dioxide to biogas produced from methanization process.

The captured carbon dioxide can't be stored infinitely, and geographical and social constraints limit the exploitation of CCS technology. Equation (34) limits the captured CO_2 to the available offshore and onshore storage formations;

$$\varphi_{CO_2}^{max} \geq \sum_h G_{ccgt-ccs,h} \times \tau_{ccgt-ccs} \times e_{ccgt} \tag{34}$$

Where $\varphi_{CO_2}^{max}$ is the maximal CO_2 storage potential, $G_{ccgt-ccs,h}$ is hourly power production from CCGT power plants equipped with CCS units, $\tau_{ccgt-ccs}$ is the carbon capture rate of post combustion CCS units, and e_{ccgt} is the specific emission of CCGT power plant with natural gas (considered with no CCS input).

Heat network can't be extended in every area and it requires a specific density, and very distant rural areas with low population densities are better off without it. Equation 35 introduces a maximal limit of heat network coverage to meet the heat demand:

$$\sum_h G_{heat-net,h} \leq g_{heat-net}^{max} \times \sum_h demand_{heat,h} \tag{35}$$

Where $g_{heat-net}^{max}$ accounts for the maximal share of the heat demand that can be satisfied by heat network.

4. Suggested input parameters

In this section we present the used input data in Shirizadeh (2020), which considers continental France for the year 2050.

4.1. VRE profiles

Variable renewable energies' (offshore and onshore wind and solar PV) hourly capacity factors have been prepared using the renewables.ninja website[5], which provides the hourly capacity factor profiles of solar and wind power from 2000 to 2018 at the geographical scale of French counties (*départements*), following the methods elaborated by Pfenninger and Staffell (2016) and Staffell and Pfenninger (2016). These renewables.ninja factors reconstructed from weather data provide a good approximation of observed data: Moraes et al. (2018) finds a correlation of 0.98 for wind and 0.97 for solar power with the observed annual duration curves (in which the capacity factors are ranked in descending order of magnitude) provided by the French transmission system operator (RTE).

The hourly VRE profiles for each of the 95 counties of France from 2000 to 2018 are extracted. Then considering the near optimal assumption of proportional installation of new plants to the existing plants, these 95 counties are aggregated to one single node. Therefore, while the model is a single node model with no spatial optimization, the spatial distribution of VRE resources has been taken into account by the spatial aggregation.

To prepare hourly capacity factor profiles for offshore wind power, first all the existing offshore projects around France are identified using the "4C offshore" website[6], and using their locations, hourly capacity factor profiles of both floating and grounded offshore wind farms are extracted. The Siemens SWT 4.0 130 has been chosen as the offshore wind turbine technology because of recent increase in the market share of this model and its high performance. The hub height of this turbine is set to 120 meters.

In a previous work (Sirizadeh et al, 2022), we showed that 2006 can be chosen as the representative year for the period of 2000-2018 regarding the weather variability of VRE technologies; thus, the hourly VRE and hydro-electricity profiles for the year 2006 are used.

4.2. Energy demand

The energy demand is categorized for each end-use: electricity, heat, transport and hydrogen (as a substitution to coal in the industry) covering all the main energy sectors; Residential and tertiary buildings, industry and construction, agriculture and transport sectors. Unlikely to the existing literature», we «defined the end-uses and allow the model

[5] https://www.renewables.ninja/

[6] https://www.4coffshore.com/

to choose the most optimal option to satisfy the demand in different sectors for different end-uses. As an example, EOLES_mv model optimizes the needed transport energy carrier (EV or ICE) for three of the four main transport categories (light and heavy vehicles and buses), and trains are all considered with electricity since it is the actual case. Similarly, EOLES optimizes heat production to satisfy the heat demand using hourly heat demand profiles, and the choice of heat production is optimized over five energy conversion technologies from electricity or gas to heat. Therefore, the model choses the optimal heat production mix endogenously among different central/decentralized and power-to-heat/gas-to-heat options to satisfy the exogenous hourly heat demand.

The annual needed energy for each energy sector is taken from ADEME's actualization of 'Energy climate' scenario (ADEME, 2017) for 2050. While different end-uses for the residential sector is provided in detail, the tertiary, agriculture and industry sectors do not include these details. Another future annual demand projection for France is provided by the French national low carbon strategy (DGEC, 2019). The sectorial demands are very close in these two studies, but the latter presents more details about the energy end-use for transport and tertiary sectors. Therefore, taking the same values of ADEME (2017), we use the final energy demand repartition for tertiary sector from the second report. Transport demand is taken from ADEME's "energy climate scenario" (ADEME, 2017) in Gp.km and Gt.km units, and using the occupation rate of different passenger and freight transport demands presented in DGEC (2019), we calculated the annual transport demand for each transport category in vehicle-kilometers. The demand for agriculture and industry are separated by end use in négaWatt's 'scenario négaWatt 2017-2050' study (négaWatt, 2017). Therefore, using the same overall energy demand in industry and agriculture provided by ADEME (2017), we use the repartition of négaWatt's heat and electricity demands to find the end-use demand for each of these technologies. Table 1 summarizes the taken annual demand for each sector and its end-use, and the source where these annual values and hourly profiles are taken from.

Table 4 Taken sectorial demands for each end-use

<table>
<tr><th>Sector</th><th colspan="2">End-use</th><th>Annual Value (Mtoe)</th><th>source</th><th>Profiles from</th></tr>
<tr><td rowspan="2">Residential</td><td colspan="2">Electricity</td><td>6.2</td><td rowspan="2">ADEME (2017), DGEC (2019)</td><td>ADEME (2015)</td></tr>
<tr><td colspan="2">Heat</td><td>18.5</td><td>Doudard (2018)</td></tr>
<tr><td rowspan="2">Tertiary</td><td colspan="2">Electricity</td><td>7.2</td><td rowspan="2">ADEME (2017), DGEC (2019)</td><td>ADEME (2015)</td></tr>
<tr><td colspan="2">Heat</td><td>7.1</td><td>Doudard (2018)</td></tr>
<tr><td rowspan="2">Agriculture</td><td colspan="2">Electricity</td><td>1.4</td><td rowspan="2">ADEME (2017), négaWatt (2017)</td><td rowspan="2">ADEME (2015)</td></tr>
<tr><td colspan="2">Heat</td><td>1.6</td></tr>
<tr><td rowspan="3">Industry</td><td colspan="2">Electricity</td><td>6.7</td><td rowspan="2">ADEME (2017), négaWatt (2017)</td><td>ADEME (2015)</td></tr>
<tr><td colspan="2">Heat</td><td>12.7</td><td>Flat</td></tr>
<tr><td colspan="2">Hydrogen</td><td>3.5</td><td>ADEME (2017)</td><td>Flat</td></tr>
<tr><td rowspan="5">transport</td><td rowspan="3">Passengers (in Gp.km)</td><td>Light</td><td>554</td><td rowspan="5">ADEME (2017)</td><td rowspan="2">Doudard (2018)</td></tr>
<tr><td>public</td><td>51</td></tr>
<tr><td>Train</td><td>187</td><td>Flat</td></tr>
<tr><td rowspan="2">Freight (in Gt.km)</td><td>Heavy</td><td>347</td><td>Doudard (2018)</td></tr>
<tr><td>Train</td><td>127</td><td>Flat</td></tr>
</table>

The preparation of each end-use demand profile is presented in the following.

4.2.1. Heat demand profile

The heat demand profiles for residential and tertiary sector for different usages (heating, hot water and cooking) are prepared using hourly, daily and monthly demand profiles presented in Doudard (2018). Hourly profiles for each weekday and weekend day are expanded using the daily profiles to the whole week, later using the monthly demand profiles we expanded these hourly demand profiles for one week to each month of the year, and with a final normalization process, we kept the annual heat demand for each usage in each of residential tertiary sector equal to the projected demand for 2050 by ADEME (2017) and DGEC (2019) scenarios.

According to Brown et al (2018) the population density should be high enough to have heat network viable. According to Persson and Werner (2011), 60% of the urban areas can be considered dense enough for a cost-effective development of district heating. Considering 87% of urban population share for France (projection for 2050 by Sénat[7]), only 52.2% of residential and tertiary sectors' heating can be provided by central heating (we assume that for agriculture and industry it is not possible to use central heating), therefore 13.36Mtoe of heating demand can be provided by central heating at maximum. On the other hand, ADEME predicts a 50% of heating from buildings sector can be satisfied by heat pumps by 2050 (ADEME, 2015). Therefore, we limit the central heating with 13.36Mtoe.

4.2.2. Transport demand profile

Like the previous section, hourly profiles for each day type (weekday or weekend) as well as a daily profile for a week, and a monthly profile for one year are available in Doudard (2018) for each passenger and freight transport category. The considered transport modes are light vehicles (particular or utility scale), buses/public transportation and trains as passenger modes and heavy vehicles, utility vehicles and trains as the freight transport modes. we excluded aerial and water transport options because of the lack of data, and the insignificance of these modes in comparison with the other transportation modes. Using the same method presented above, we prepared annual hourly demand profile for each of the transport modes and categorized them in four main categories of light vehicles, heavy vehicles, buses and trains[8]. Using daily, monthly and annual correction factors, we maintained the annual transport demand projected by ADEME (2017) and DGEC (2019) scenarios in vehicle-kilometers.

[7] https://www.senat.fr/rap/r10-594-1/r10-594-14.html

[8] Because of lack of data and continuity of the public transportation services, we considered a flat hourly demand profile for the transport demand by train.

4.2.3. *Electricity demand profile*

ADEME's (2015) central scenario hourly demand profile for 2050 is taken as the electricity demand profile for the model. This demand profile amounts to 422.3 TWh_e/year, 12% less than the average power consumption in the last 10 years. This takes into account foreseeable change in the demand profile up to 2050, including a reduced demand for lighting and heating and an increased demand for air conditioning and electric vehicles. This demand profile includes heating, cooking, hot water usage and electric vehicle charging demand, therefore they should be subtracted from this demand profile to reach to an only electricity demand. By subtracting the heat and transport demand profiles (normalized again since only a part of these demands is satisfied by electricity), we build an hourly specific electricity demand profile for 2050.

4.2.4. *Hydrogen demand profile*

The needed coal for the steel production is estimated to be 3.5Mtoe (ADEME, 2017 and DGEC, 2019). we consider the same amount of energy intensity, but coal is replaced hydrogen (thus a pessimist consideration). The annual hydrogen demand is divided by 8760 (number of time-slices in in year) to produce a flat demand profile for hydrogen.

4.2.5. *Industry demand profiles*

The energy demand for industry is the same value as ADEME (2017), but since no repartition between the usages are provided, we use the heat-electricity usage repartition provided by négaWatt's "scenario négaWatt 2017-2050" (négaWatt, 2017). Because of lack of data and high flexibility of industrials' energy demand with respect to the energy price, we consider a flat electricity and heat profile for industry, and we add them to the heat and electricity profiles constructed in previous sections.

4.3. Limiting capacity and energy production constraints

The maximal potentials used in this study are maximal capacities of VRE technologies from ADEME's 'electric system trajectories 2020-2060' study (ADEME, 2018a), the maximal and existing hydro-electricity capacities from ADEME (2015), and the hourly run-of-river and lake-generated hydro-electricity profiles from national open data forum of France, provided by RTE (French transmission network operator) for each year from 2000 to 2018. By summing the hourly lake-generated hydro-electricity profiles over each month, we calculated monthly maximal electricity that can be produced from this technology for each month from 2000 to 2018. Similarly, the maximal biogas production from renewable gas[9] production technologies (methanization and pyro-gasification) are taken from the

[9] Renewable gas, also known as bio-methane is a biogas which has an upgraded quality similar to fossil natural gas or methanation as a power-to-gas option (hydrogen production from water electrolysis and methanation by Sabatier reaction of hydrogen and green CO2) that can be injected directly to the gas network. In its biogas form, it is

upper limits of ADEME's '100% renewable gas mix' study (ADEME, 2018b). According to the same study, the production of biogas from methanization leads to 60% of methane and 30% of carbon dioxide, which is used as the green CO_2 for the methanation process.

4.4. Economic parameters

Table 2 summarizes the economic parameters (and their sources) of energy supply technologies used as input data in EOLES model. Since four energy carriers are considered (electricity, gas, hydrogen and heat), depending on the considered carrier, the values are either in kW_e and MWh_e (for electricity) or in kW_{th} and MWh_{th} (for gas and heat). Since we study the French optimal energy sector for 2050, the used economic parameters are all the projections for 2050.

Table 5. Economic parameters of energy production technologies

Technology	**Overnight costs (€/kW)**	**Lifetime (years)**	**Annuity (€/kW/year)**	**Fixed O&M (€/kW/year)**	**Variable O&M (€/MWh)**	**Construction time (years)**	**Source**
Offshore wind farm - floating	3,660	30	236.2	73.2	0	1	JRC (2017)
*Offshore wind farm - monopile**	2,330	30	150.9	47	0	1	JRC (2017)
*Onshore wind farm**	1,130	25	81.2	34.5	0	1	JRC (2017)
*Solar PV**	423	25	30.7	9.2	0	0.5	JRC (2017)
Hydroelectricity – lake and reservoir	2,275	60	115.2	11.4	0	1	JRC (2017)
Hydroelectricity – run-of-river	2,970	60	150.4	14.9	0	1	JRC (2017)
Nuclear power	3,750	60	262.6	97.5	9.5**	10	JRC (2014)
Natural gas	-	-	-	-	23.5***	-	IEA (2019)
Methanization	370****	20	29.7	37	50	1	ADEME (2018b)
Pyro-gasification	2500	20	200.8	225	32*****	1	ADEME (2018b)

*For offshore wind power on monopiles at 30km to 60km from the shore, for onshore wind power, turbines with medium specific capacity (0.3kW/m^2) and medium hub height (100m) and for solar power, an average of the costs of utility scale, commercial scale and residential scale systems without tracking are taken into account. In this cost allocation, we consider solar power as a simple average of ground-mounted, rooftop residential and rooftop commercial technologies. For lake and reservoir hydro we take the mean value of low-cost and high-cost power plants.
**This variable cost accounts for €2.5/MWh-e of fuel cost and €7/MWh of other variable costs, excluding waste management and insurance costs.
*** The price projected for Europe in 2040 in the sustainable development scenario, standing for 7.5$/MBtu.
****The overnight cost for methanization is the investment cost of the purification plants for syngas.

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produced from biochemical processes on the organic waste (methanization) and gasification of energy wood and biomass.

*****The overnight cost only accounts for the gasification plants, while the energy wood used is accounted for in variable costs.

Construction time is the period between the date of the first expenditure on public works and the last day of construction and tests, when the plant starts operation; local authority permit processes and the preliminary business studies are, therefore, not included in this period.

It should be noted that the annuity includes the interest during construction (IDC) relating to the construction time, and the decommissioning cost for nuclear power plants. The construction time for nuclear power plants can be as little as seven years, while the three projects of Olkiluoto in Finland, Hinkley Point C in the UK and Flamanville 3 in France show much longer construction times. According to NEA (2018), an average construction time of 10 years is a good estimation for new nuclear power plants. The same report provides a labor-during-construction profile: the annual construction expenditure has been calculated assuming expenditure to be proportional to labor each year. Using the formula provided by the GEN IV international forum (2007), the interest during construction can be calculated using equation (1):

$$IDC = \sum_{j=1}^{ct} C_j[(1+r)^{t_{op}-j} - 1] \quad (36)$$

Where IDC is the interest during construction, C_j is the money spent during year j of construction, ct is the construction time and t_{op} is the year the power plant starts operating. Solving this equation leads to IDC=€1,078/kW. According to the same GEN IV study, decommissioning of a nuclear power plant accounts for 10% of the overnight costs. Including these interest-during-construction and decommissioning costs, the final investment cost is found to be €5,311/kW, which is the value used to calculate the annuity.

Table 3 shows the economic parameters of energy conversion technologies.

Table 6. Economic parameters of conversion technologies

Technology	Overnight costs (€/kW)	Lifetime (years)	Annuity (€/kW/year)	Fixed O&M (€/kW/year)	Variable O&M (€/MWh)	Construction time (years)	Conversion efficiency	Source
OCGT	550	30	35.28	16.5	0	1	0.45	JRC (2014)
CCGT	850	30	54.53	21.25	0	1	0.63	JRC (2014)
CCGT-CCS	1280	30	82.12	32	5.76*	1	0.55	JRC (2017)
Electrolysis (Power-to-H2)	450	25	31.03	6.75	0	0.5	0.8	ENEA (2017)
Methanation (Power-to-CH4)**	450/700	25/20	86.05	59.25	5***	0.5	0.8/0.79	ENEA (2017)
Resistive	100	20	7.86	2	0	0.5	0.9	Brown et al. (2018)
Individual heat pump	1050	20	82.54	36.75	0	0.5	3.5	Henning and Palzer (2014)
Central heat pump	700	20	55.02	24.5	0	0.5	2	Henning and

								Palzer (2014)
Central gas boiler	63	20	4.95	0.945	0	0.5	0.9	Brown et al. (2018)
Decentral gas boiler	175	20	13.76	3.5	0	0.5	0.9	Brown et al. (2018)

* This variable cost accounts for a 500km CO_2 transport pipeline and offshore storage costs estimated by Rubin et al. (2015).
**Methanation is the combination of hydrogen production from electrolysis and Sabatier reaction of green CO_2 as by-product from methanization with the produced hydrogen, therefore the economic parameters of each production is presented as electrolysis/Sabatier.
***As in Shirizadeh et al. (2022).

The conversion efficiency is in the output energy form over the input energy form. Therefore, for Gas-to-Power technologies (OCGT, CCGT and CCGT-CCS) it is kW_e/kW_{th}, for Power-to-Gas technologies (electrolysis and methanation) it is kW_{th}/kW_e, for Power-to-Heat technologies (resistive heating and electric heat pump) ins kW_{th}/kW_e and for Gas-to-Heat technologies (gas heat pump and central and decentral gas boilers) in kW_{th}/kW_{th}.

Table 4 shows the economic parameters of power storage technologies, and table 5 shows the economic parameters for transport technologies.

Table 7. Economic parameters of storage technologies

Technology	Overnight costs (€/kW)	CAPEX (€/kWh)	Lifetime (years)	Annuity (€/kW/year)	Fixed O&M (€/kW/year)	Variable O&M (€/MWh)	Storage annuity (€/kWh/year)	Construction time (years)	Efficiency (input / output)	Source
Pumped hydro storage (PHS)	500	5	55	25.8050	7.5	0	0.2469	1	95%/90%	FCH-JU (2015)
Battery storage (Li-Ion)	140	100	12.5	15.2225	1.96	0	10.6340	0.5	90%/95%	Schmidt (2019)
ITES	0	18.38	20	-	0	0	1.4127	0.5	90%/90%	Brown et al. (2018)
CTES	0	0.64	40	-	0	0	0.0348	1	90%/75%	Brown et al. (2018)
Gas storage*	0	0	80	0	0	2	0	-	100%/99%	CRE (2018)

*The French gas network is already operational for methane injection; therefore, no network development cost is considered. However, the network usage is fee of 2€/MWh_{th} for gas network is considered according to French energy regulation commission (CRE, 2018).

Table 8 Economic parameters for two transport engine types

Technology	Charging infrastructure (€/kW)	Reservoir (€/kWh)	Lifetime (years)	Charging annuity (€/kW/year)	Reservoir annuity (€/kWh/year)	Source
Electric vehicles	81.7*	100	10	11.08	12.64	CGDD (2017)
ICE vehicles	180**	0	15	17.14	0	Doudard (2018)

*We consider a charging point cost of 600€ for 7kW of charging power.
**According to Doudard (2018), a gas charging station costs 300,000€ which can serve 400 vehicles per day, considering nearly 100kWh$_{th}$ (384km of autonomy) of charging at each charge, we find this cost.

All the remaining technical, land-use related, and country-specific parametrization of the model is presented in appendix 4.

4.5. Choice of the discount rate

The discount rate recommended by the French government for use in public socio-economic analyses is 4.5% (Quinet, 2014). This discount rate is used to calculate the annuity in the objective function, using the following equation:

$$annuity_{tec} = \frac{DR \times CAPEX_{tec}((DR \times ct_{tec})+1)}{1-(1+DR)^{-lt_{tec}}} \quad (37)$$

Where *DR* is the discount rate, ct_{tec} is the construction time, lt_{tec} is the technical lifetime and $annuity_{tec}$ is the annualized investment of the technology tec.

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