CIRED Working Paper
N° 2020-80 - Février 2020

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Behrang Shirizadeh
Quentin Perrier
Philippe Quirion

Corresponding author: shirizadeh@centre-cired.fr

Centre international de recherche sur l'environnement et le développement
Unité mixte de recherche CNRS - Ecole des Ponts ParisTech - Cirad - EHESS - AgroParisTech
Site web: www.centre-cired.fr Twitter: @cired8568
Jardin Tropical de Paris -- 45bis, avenue de la Belle Gabrielle 94736 Nogent-sur-Marne Cedex

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Behrang Shirizadeh[1,2]*, Quentin Perrier[1] and Philippe Quirion[1]

0. EOLES_elecRES model

EOLES_elecRES is a dispatch and investment model that minimizes the annualized power generation and storage costs, including the cost of connection to the grid. It includes six power generation technologies: offshore and onshore wind power, solar photovoltaics (PV), run-of-river and lake-generated hydro-electricity, and biogas combined with open-cycle gas turbines. It also includes three energy storage technologies: pump-hydro storage (PHS), batteries and methanation combined with open-cycle gas turbines. These technologies are shown in Figure 1.

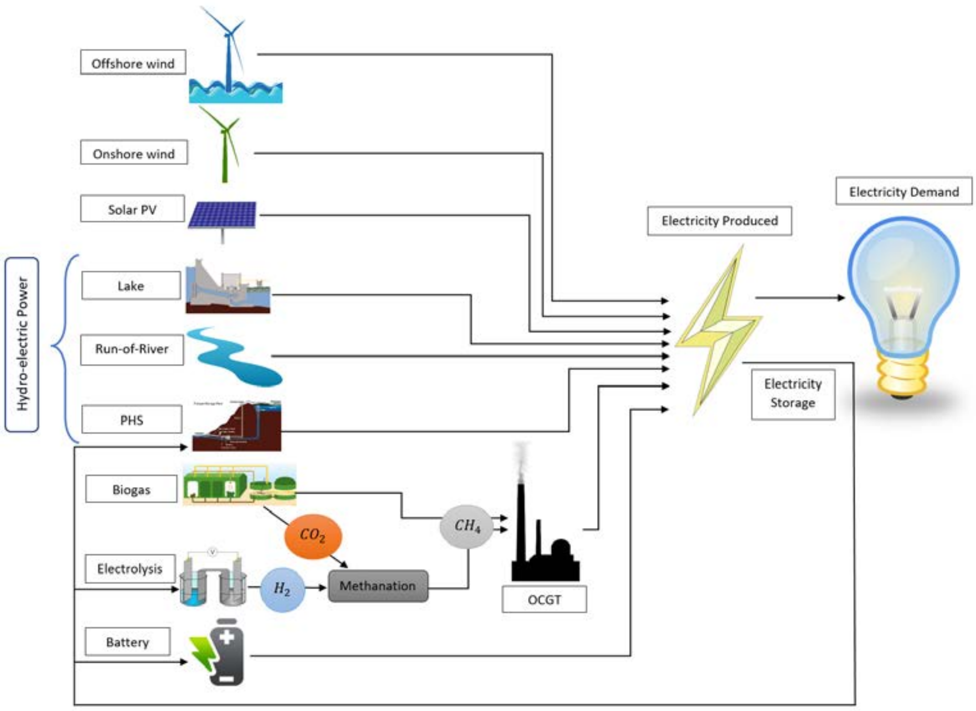

Figure 1 EOLES_elecRES model graphical representation

The model is written in GAMS and solved using the CPLEX solver. The code and data are available on Github.[3] Figure 2 provides an illustrative output of the model, i.e. the optimal dispatch for a week in winter and for a week in summer, for each hour of the week.

[1] CIRED-CNRS, 45 bis avenue de La Belle Gabrielle, 94736 Nogent sur Marne Cedex, France
[2] TOTAL, GRP, R&D department, 2 place Jean Millier, 92078 Paris la Défense Cedex, France.
* Corresponding author: shirizadeh@centre-cired.fr, +33 (0)1 43 94 74 78

[3] https://github.com/BehrangShirizadeh/EOLES_elecRES

The main simplification assumptions in the EOLES_elecRES model are as follows; it considers continental France as a single node, demand is inelastic, and the optimization is based on full information about the weather and electricity demand. 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.

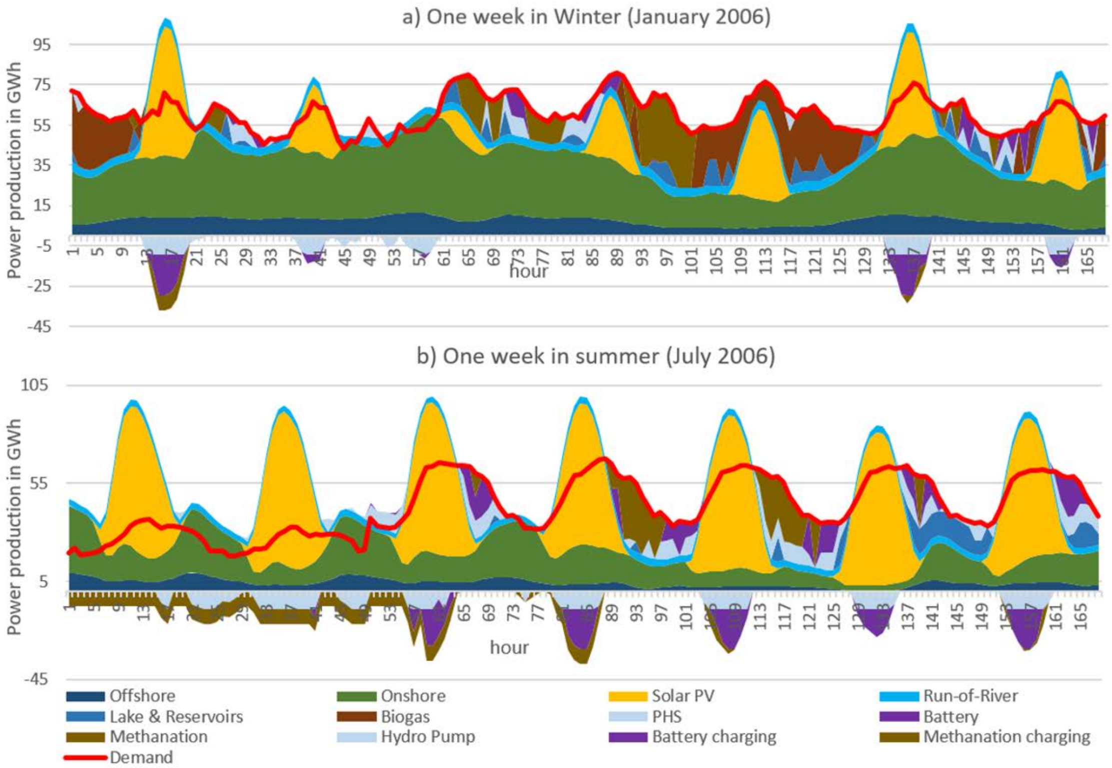

Figure 2 Hourly power generation, electricity demand, storage charge and discharge profiles for (a) the third week of January (Winter) and (b) the third week of July (Summer) 2006

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_elecRES model respectively. The 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_elecRES model and table 2 the parameters. Throughout the paper, every energy unit (e.g. MWh) or power unit (e.g. MW) is expressed in electricity-equivalent. For instance, some energy is stored in the form of methane, to be transformed later into electricity using open-cycle natural gas plants with 45% efficiency. In this case, when we indicate that 45 MWh_e is stored in the natural gas network, it means that 100 MWh of methane is stored, which will allow 45 MWh_e of electricity to be generated.

Table 1 Sets and indices of the EOLES_elecRES model

Index	Set	Description
h	∈ H	**Hour:** the number of hours in a year, from 0 to 7659
m	∈ M	**Month:** the twelve months, from January to December
tec	∈ TEC	**Technologies:** The set of all electricity generation and energy storage technologies (offshore, onshore, PV, river, lake, biogas, gas, PHS, battery, methanation)
gen	∈ GEN ⊆ TEC	**Generation:** Electricity generation technologies (offshore, onshore, PV, river, lake, biogas, gas)
vre	∈ VRE ⊆ TEC	**VRE:** Variable renewable electricity generation technologies (offshore, onshore, PV)
str	∈ STR ⊆ TEC	**Storage:** Energy storage technologies (PHS, battery, methanation)
$ncomb$	∈ NCOMB ⊆ TEC	**Non-combustible** generation technologies (offshore, onshore, PV, river, lake, PHS, battery)
$comb$	∈ COMB ⊆ TEC	**Combustible** generation technologies (biogas, methanation)
frr	∈ FRR ⊆ TEC	**Frequency restauration reserves:** Technologies contributing to secondary reserves requirements (lake, PHS, battery, gas)

Table 2 Parameters of the EOLES_elecRES model

Parameter[4]	Unit	Description
$month_h$	[-]	A parameter to show which month each hour is in
$cf_{vre,h}$	[-]	Hourly production profiles of variable renewable energies
$demand_h$	$[GW_e]$	Hourly electricity demand profile
$lake_m$	$[GWh_e]$	Monthly extractable energy from lakes
$river_h$	[-]	Hourly run-of-river capacity factor profile
ε_{vre}	[-]	Frequency restoration requirement because of forecast errors on the production of each

[4] The suggested values for France are available in GitHub page presented above.

		variable renewable energy
q_{tec}^{ex}	$[GW_e]$	Existing capacity by technology
$annuity_{tec}$	[M€/GW_e/year]	Annualized capital cost of each technology
$annuity_{str}^{en}$	[M€/GWh/year]	Annualized capital cost of energy volume for storage technologies
$capex_{str}^{ch}$	[M€/GW /year]	Annualized capital cost of storage technology charging power
$fO\&M_{str}^{ch}$	[M€/GW /year]	Fixed operation and maintenance cost of storage technology charging power
$fO\&M_{tec}$	[M€/GW_e /year]	Annualized fixed operation and maintenance cost
$vO\&M_{tec}$	[M€/GWh_e]	Variable operation and maintenance cost of each technology
η_{str}^{in}	[-]	Charging efficiency of storage technologies
η_{str}^{out}	[-]	Discharging efficiency of storage technologies
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
e_{biogas}^{max}	$[TWh_e]$	Maximum yearly energy that can be generated from biogas
$\delta_{uncertainty}^{load}$	[-]	Uncertainty coefficient for hourly electricity demand
$\delta_{variation}^{load}$	[-]	Load variation factor

2. Variables

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

Table 3 Variables of EOLES_elecRES 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

In EOLES, dispatch and investment are determined simultaneously by linear optimization. CAPEX (capital expenditure) and OPEX (operational expenditure) are optimized simultaneously.

The objective function, shown in Equation (1), is the sum of all costs over the chosen period, including fixed investment costs, fixed O&M costs (which are both annualized) and variable costs. For some storage options, in addition to the CAPEX related to charging capacity per kW_e, another type of CAPEX is introduced: a capex related to energy capacity, per kWh_e.

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

where Q_{tec} represents the installed capacities of production, $VOLUME_{str}$ is the volume of energy storage in GWh, S_{str} is the capacity of storage in GW, $annuity$ is the annualized investment cost, $fO\&M$ and $vO\&M$ respectively represents fixed and variable operation and maintenance costs and $G_{tec,h}$ is the hourly generation of each technology.

3.2. Adequacy equation

Electricity demand must be met for each hour. If power production exceeds electricity demand, the excess electricity can be either sent to storage units or curtailed (equation 2).

$$\sum_{tec} G_{tec,h} \geq demand_h + \sum_{str} STORAGE_{str,h} \qquad (2)$$

Where $G_{tec,h}$ is the power produced by technology *tec* at hour *h* and $STORAGE_{str,h}$ is the energy entering the storage technology *str* at hour *h*.

3.3. Renewable power production

For each variable renewable energy (VRE) technology, the hourly power production is given by the hourly capacity factor profile multiplied by the installed capacity available for each hour (equation 3).

$$G_{vre,h} = Q_{vre} \times cf_{vre,h} \quad (3)$$

Where $G_{vre,h}$ is the electricity 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 (equation 4):

$$STORED_{str,h+1} = STORED_{str,h} + (STORAGE_{str,h} \times \eta_{str}^{in}) - (\frac{G_{str,h}}{\eta_{str}^{out}}) \qquad (4)$$

Where $STORED_{str,h}$ is the energy in storage option *str* at hour *h*, while η_{str}^{in} and η_{str}^{out} are the charging and discharging efficiencies.

3.5. Secondary reserve requirements

Three types of operating reserves are defined by ENTSO-E (2013), according to 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 impacted by VRE integration. 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 (5). 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:

$$\sum_{frr} RSV_{frr,h} = \sum_{vre}(\varepsilon_{vre} \times Q_{vre}) + demand_h \times (1 + \delta^{load}_{variation}) \times \delta^{load}_{uncertainty} \qquad (5)$$

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. The method for calculating these various coefficients according to ENSTO-E guidelines is detailed by Van Stiphout et al. (2017).

3.6. Power production constraints

The relationship between hourly-generated electricity and installed capacity can be calculated using equation (6). 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.

$$G_{tec,h} \leq Q_{tec} \qquad (6)$$

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 (7).

$$Q_{frr} \geq G_{frr,h} + RSV_{frr,h} \qquad (7)$$

Monthly available energy for the hydroelectricity generated by lakes and reservoirs is defined using monthly lake inflows (equation 8). 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).

$$lake_m \geq \sum_{for\ h \in m} G_{lake,h} \qquad (8)$$

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

Run-of-river power plants represent another source of hydro-electricity power. River flow is also strongly dependent on meteorological conditions and it can be considered as a variable renewable energy resource. Hourly capacity factor profile of this energy source ($river_h$) should be used to produce hourly power production from this technology, presented in equation (9);

$$G_{river,h} = Q_{river} \times river_h \qquad (9)$$

As shown in Figure 1, two renewable gas technologies are considered; biogas and methanation. Both of them produce renewable methane, which can be used in gas power plants. In the model, the latter is considered to be an open cycle gas turbine (OCGT) due to its high operational flexibility and equation (10) shows the relationship of the power production from these two methane resources;

$$G_{gas,h} = \sum_{comb} G_{comb,h} \, (10)$$

Where $G_{comb,h}$ is the power production from each renewable gas resource, and $G_{gas,h}$ is the power production from the OCGT power plant which uses these two resources as fuel.

3.7. Resource related constraints

The energy that can be produced by biogas is limited, since the main resources of this energy are methanization (anaerobic digestion) and pyro-gasification of solid biomass. Both processes are limited by several constraints which is presented in equation 11.

$$\sum_{h=0}^{8759} G_{biogas,h} \leq e_{biogas}^{max} \qquad (11)$$

Where e_{biogas}^{max} accounts for maximal annual biogas that can be used for electricity production, and $G_{biogas,h}$ is the hourly electricity that can be produced from biogas.

The maximum installed capacity of each technology depends on land-use-related constraints, social acceptance, the maximum available natural resources and other technical constraints; therefore, a technological constraint on maximum installed capacity is defined in equation (12) where q_{tec}^{max} is this capacity limit:

$$Q_{tec} \leq q_{tec}^{max} \qquad (12)$$

3.8. Storage related constraints

To prevent optimization leading to a very high amount of stored energy in the first hour ($STORED_{str,0}$) represented and a low one in the last hour ($STORED_{str,8759}$), we add a constraint to ensure the replacement of the consumed stored electricity in every storage option (equation 13):

$$STORED_{str,0} = STORED_{str,8759} + (STORAGE_{str,8759} \times \eta_{str}^{in}) - (\frac{G_{str,8759}}{\eta_{str}^{out}}) \, (13)$$

While equations (4) and (13) 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 ($VOLUME_{str}$) in equation 14:

$$STORED_{str,h} \leq VOLUME_{str} \qquad (14)$$

Equation (15) limits the energy entry to the storage units to the charging capacity of each storage unit (S_{str}), which means that the charging capacity cannot exceed the discharging capacity (Q_{str}).

$$STORED_{str,h} \leq S_{str} \leq Q_{str} \qquad (15)$$

4. Suggested input parameters

In this section we present the used input data in Shirizadeh et al. (2019), which considers France as a single node for the year 2050. All the input parameters and data series can be found on Github[5].

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[6], which provides the hourly capacity factor profiles of solar and wind power from 2000 to 2017 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 in-situ observations provided by the French transmission system operator (RTE).

To prepare hourly capacity factor profiles for offshore wind power, we first identified all the existing offshore projects around France using the "4C offshore" website[7], and using their locations, we extracted the hourly capacity factor profiles of both floating and grounded offshore wind farms. 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. The input data for each weather year from 2000 to 2018 can be found on GitHub.

4.2. Hourly electricity demand profiles

Hourly electricity demand is ADEME (2015)'s central demand scenario for 2050. This demand profile falls in the middle of the four proposed demand scenarios for 2050 in France by Arditi et al. (2013) during the national debates on the French energy transition (DNTE). It amounts to 422 TWh_e/year, 12% less than the average power consumption in the last 10 years. We include this demand profile rather than the one observed in recent years because by 2050, electricity demand will have been impacted by climate change, progress in energy efficiency and new uses of electricity.

[5] https://github.com/BehrangShirizadeh/EOLES_elecRES/tree/master/inputs
[6] https://www.renewables.ninja/
[7] https://www.4coffshore.com/

4.3. Economic parameters

The economic parameters for generation technologies are taken from JRC (2014, 2017) and summarized in Table 4. It is worth mentioning that the grid upgrading cost of €24.6/kW for new renewable power plants mandated by the transport system operator RTE and by the distribution system operator ENEDIS (RTE, 2018) has been added to the capital expenditure values of each VRE technology. The annuities (annualized CAPEX) are the results of these calculations.

Table 4 Economic parameters of power production technologies

Technology	**CAPEX (€/kW$_e$)**	**Lifetime (years)**	**Annuity (€/kW$_e$/year)**	**Fixed O&M (€/kW$_e$/year)**	**Variable O&M (€/MWh$_e$)**	**Source**
*Offshore wind farm**	2330	30	144.3677	47.0318	0	JRC (2017)
*Onshore wind farm**	1130	25	77.6621	34.5477	0	JRC (2017)
*Solar PV**	425	25	30.0052	9.2262	0	JRC (2017)
Hydroelectricity – lake and reservoir	2275	60	110.2334	11.375	0	JRC (2017)
Hydroelectricity – run-of-river	2970	60	143.9091	14.85	0	JRC (2017)
Biogas (Anaerobic digestion)	2510	25	135.5066	83.9	3.1	JRC (2017)
OCGT	550	30	33.7653	16.5	0**	JRC (2014)

*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.
**Equal to fuel price; here the biogas and biomethane price which are endogenous.

For the storage technologies, the "Commercialization of Energy Storage in Europe" report prepared by FCH-JU (2015) and a recent article by Schmidt et al. (2019) about long-term cost projections of storage technologies have been used respectively for pumped hydro storage and Li-Ion battery storage options. "The potential of Power-to-Gas" study by ENEA consulting (2016) has been used for methanation storage. Using these three studies the 2050 cost projection of storage technologies are presented in

Table 5. The cost of methanation is made up of the cost of electrolysis units and the Sabatier reaction[8].

Table 5 Economic parameters of storage technologies

Technology	***Overnight costs (€/kW$_e$)***	***CAPEX (€/kWh$_e$)***	***Lifetime (years)***	***Annuity (€/kW$_e$/year)***	***Fixed O&M (€/kW$_e$/year)***	***Variable O&M (€/MWh$_e$)***	***Storage annuity (€/kWh$_e$/year)***	***Efficiency (input / output)***	***Source***
Pumped hydro storage (PHS)	500	5	55	25.8050	7.5	0	0.2469	95%/90%	FCH-JU (2015)
Battery storage (Li-Ion)	140	100	12.5	15.2225	1.96	0	10.6340	90%/95%	Schmidt (2019)
Methanation	1150	0	20/25*	87.9481	59.25	5.44	0	59%/45%	ENEA (2016)

*The lifetime of electrolysis units is 20 years, while the lifetime of methanation units is 25 years.

The carbon dioxide required for methanation is assumed to come from capturing and transporting the excess carbon dioxide resulting from the methanization process (to produce biogas). About 30% of the product of bio-methane production from methanization by anaerobic digestion is gas phase carbon dioxide (Ericsson, 2017). According to ZEP (2011), the cost of transporting carbon dioxide along a 200km onshore pipeline is $€4/tCO_2$.

Considering a 100km long onshore pipeline (considering maximum 100km of distance between the methanation units and the biogas production units), the CO_2 transport cost for the methanation storage is €1/MWh (See appendix 5), to be added to the gas storage cost which is €2/MWh (according to the French energy regulation commission (CRE, 2018), the variable cost of the methanation storage is $€3/MWh_e$.

4.4. Choice of the discount rate

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

$$annuity_{tec} = \frac{DR \times CAPEX_{tec}}{1-(1+DR)^{-lt}} \qquad (16)$$

Where *DR* is the discount rate.

[8] The reaction that produces methane from hydrogen and carbon dioxide is called the Sabatier reaction.

4.5. Country-specific resource-limiting parameters

As mentioned in sectioned 3.7 several resource related limiting constraints exist. Equations (11) and (12) introduce two main resource related parameters; maximum installable capacity and maximal annual power that can be produced from biogas. We use ADEME's electricity mix trajectories for 2020-2060 study (ADEME, 2018) for maximal installable capacity of renewable technologies, and $15TWh_e$ for maximal annual electricity production from biogas (ADEME, 2013). Table 6 summarizes maximal installable renewable electricity capacity;

Table 6 Limiting parameters suggested for France for year 2050

Technology	**Lake & reservoir**	**Run-of-river**	**PHS**	**Offshore wind**	**Onshore wind**	**Solar PV**
Maximal capacity (GW)	13	10.5	9.3/180*	20	120	218

*9.3 accounts for the charging and discharging power in GW_e and 180 accounts for the maximal storage volume in GWh_e.

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