Relative role of electricity and gas in a carbon-neutral future: insights from an energy system optimization model

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Abstract

An effective decision regarding the future energy mix must be based on multi-sectorial optimization that considers the key energy supply, carrier, conversion and storage options in an endogenous way, with high temporal resolution where positive and negative emissions are both internalized. The existing literature fails to meet all these conditions, leaving several open questions. To address the relative role of electricity and non-fossil gas in a cost-effective decarbonized energy system, we develop an integrated model including optimization of dispatch and investment for the whole energy sector, meeting all the necessary conditions. We apply this model to the French energy system for a wide range of social cost of carbon scenarios in 2050.

Unlike most energy scenarios, which are nearly fully electrified, we find that renewable gas provides at least 22% of the energy supply in a carbon neutral energy system, where this carbon-neutrality can be achieved with a social cost of carbon of €200/tCO_2. In such an energy system, renewables become the main component of the primary energy supply (up to 80%). A fully electrified heat sector and a highly gas-dependent transport sector fueled with renewable gas help to achieve carbon-neutrality at lowest cost.

Keywords: Energy systems modeling; large-scale renewable integration; sector-coupling; social cost of carbon; renewable gas; nuclear energy; variable renewables; negative emissions.

JEL classification: C61; H23; O21; Q21; Q41; Q47; Q48

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1. Introduction

In order to meet the 1.5°C global warming objective, the European commission's 'European Climate Law' proposal sets the target of achieving climate neutrality by 2050 (European Commission, 2019). Similarly, several European states have set ambitious greenhouse gas (GHG) emission reduction targets; for instance, the official target in the French 'energy-climate law' is to reach net zero GHG emissions by 2050 (DGEC, 2019). Energy scenarios aiming at carbon-neutrality by 2050 vary with respect to the role of different energy carriers, particularly gas and electricity. For instance, the French Environment and Energy Management Agency (ADEME)'s 'energy-climate scenario 2035-2050' and the French Ministry of Ecological Transition and Solidarity's 'national low-carbon strategy', predict highly electrified heating and transport sectors in France with up to 60% of the primary energy supply being electrified (ADEME, 2017 and SNBC, 2018). However, négaWatt's scenario suggests 35% of electrification for the primary energy supply (négaWatt, 2017), with the transport sector dominated by gas-fueled internal combustion engines.

These national scenarios are based on top-down allocation of energy sources and carriers and do not result from optimization. Considering the entire energy system as an integrated whole and optimizing it on a national scale is complicated and highly demanding in computational terms. However, a rigorous energy policy that fully considers the relative role of different energy sources, carriers and storage options must be based on optimal allocation of those options. This optimization must include endogenous choice of energy carriers and should include the main low-carbon options (renewable electricity, biogas, carbon capture and storage and nuclear power), since choice of technology and optimal allocation of energy carriers are interdependent. For instance, considering power-to-gas as a long-term storage option in the context of the electricity sector alone requires highly inefficient gas-to-power conversion technologies which may be difficult to render profitable (Van Leeuwen and Molder, 2018). To avoid overestimation of storage needs, the studies should focus on the entire energy system, not on a single sector (Blanco and Faai, 2018). Therefore, the endogenous technology choice must include a multi-sectorial approach to enable sector-coupling. Sector-coupling enables optimal allocation of different energy sources, carriers and storage options to satisfy the main end-use demands by allowing an endogenous choice of energy carrier and conversion options for different end-uses (Lund et al, 2017).

Correct dimensioning of short-term and long-term storage options requires high temporal resolution. A coarser-than-hourly temporal resolution lowers the model accuracy due to short-term variations in wind speed and solar radiation, leading to underestimation in the dimensioning of short-term storage options (Brown et al, 2018a). Similarly, long-term storage options (typically inter-seasonal storage) are among cost-optimal solutions due to annual cycles of wind, solar irradiation and temperature (Shirizadeh et al, 2019 and Schill and Zerrahn, 2018), and correct dimensioning of long-term storage options requires the modeling of a continuous, long period of time, rather than defining representative periods (Pfenninger, 2017). Therefore, modelling an optimal energy mix must consider at least one full year at an hourly resolution.

Achieving carbon-neutrality in the energy sector requires not only penalization of positive emissions as a carbon tax, but also promotion of negative emissions by remuneration. Introducing a tax on positive emissions and remuneration for negative emissions can incentivize investment in negative emission technologies and discourage the use of fossil sources (Shirizadeh and Quirion, 2020). To sum up, identification of the relative role of different energy carriers requires an integrated optimization that (1) includes the main energy sectors, (2) is based on endogenous energy carrier and technology choice, (3) includes the main low-carbon options, (4) has a high temporal resolution over at least a full year and (5) internalizes both positive and negative CO_2 emissions.

A very big proportion of the existing literature on energy system optimization is based on a single sector (Olauson et al, 2016, Schlachtberger et al, 2017, Schlachtberger et al, 2018, Zeyringer et al, 2018, Shirizadeh and Quirion, 2020, etc.). Although sector-coupling has gained significant attention recently, the existing energy system optimization studies that include sector-coupling either lack the required temporal precision (Doudard, 2018), or lack complete endogeneity in the interactions between energy carriers and end-use demands. They also suffer from limited representation of the main low-carbon options, especially negative emission technologies (Bloess et al, 2018, Brown et al, 2018b, Victoria et al, 2019, Zhu et al, 2019 and Zhu et al, 2020). Moreover, none of these studies include internalization of both negative and positive CO_2 emissions, which is a key element in studying the potential of different mitigation options. To include all the conditions mentioned above in an optimal decision-making process aiming at carbon-neutrality, we develop the EOLES_mv (Energy Optimization for Low Emission Systems, multi-vector) model, which meets all the conditions highlighted above. EOLES_mv simultaneously optimizes dispatch (providing an hourly supply-demand balance) and investment in production, storage, network and energy conversion capacities, in order to minimize the total cost of energy systems.

Applying this model to the French energy situation, we study the optimal energy system for different social cost of carbon[1] scenarios (from 0 to €500/tCO_2), and we study the relative role of the main energy carriers and the importance of the key low-carbon technologies in achieving carbon-neutrality in cost-optimal ways. Finally, accounting for the main uncertainties, we propose a robust social cost of carbon to ensure that the goal of deep decarbonization is achieved.

The remainder of this paper is organized as follows. Section 2 presents the methods: the EOLES_mv model and the input parameters. Section 3 presents the results, which are discussed in section 4. Section 5 highlights the main findings and concludes.

2. Methods

2.1. The 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. This model is a greenfield optimization model, which calculates a cost-optimal end point, taking into account the main technical and resource availability constraints. Therefore, this model does not produce a dynamic trajectory but a static optimal final state. In order to account for precise dispatch with correct dimensioning of storage technologies and the seasonal and intra-daily variability of demand and energy production from renewable resources, the selected optimization period is a full year with hourly time-steps.

This model considers a country as a single node using the copper-plate assumption: spatial optimization is, therefore, not considered in this model. Although including spatial optimization and therefore transmission costs can increase or decrease the overall system cost, in a previous article we

[1] Social cost of carbon (SCC) is the monetary value that society attributes to one ton of supplementary CO_2 emissions to internalize the damages caused by it.

showed that modeling France as a single node with a near-optimal assumption of installation of new plants in proportion to existing facilities (which is the case in this study – section 2.2.1 and Appendix 2), leads to much faster calculation (240 times) than considering France as four nodes, with negligible error in installed capacity of the key technologies and the overall cost of the system (Shirizadeh et al, 2019).

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

The main simplification assumptions in the EOLES family of models are as follows: demand is inelastic[1], 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. The model is written in GAMS and solved using the CPLEX solver. The GAMS scripts and the input data are available on Github.[2] The model's indices, parameters, variables and equations are presented in Appendix 1.

[1] The inelastic demand assumption cannot be realistic for low social cost of carbon values. This is discussed briefly in section 4.5.
[2] https://github.com/BehrangShirizadeh/EOLES

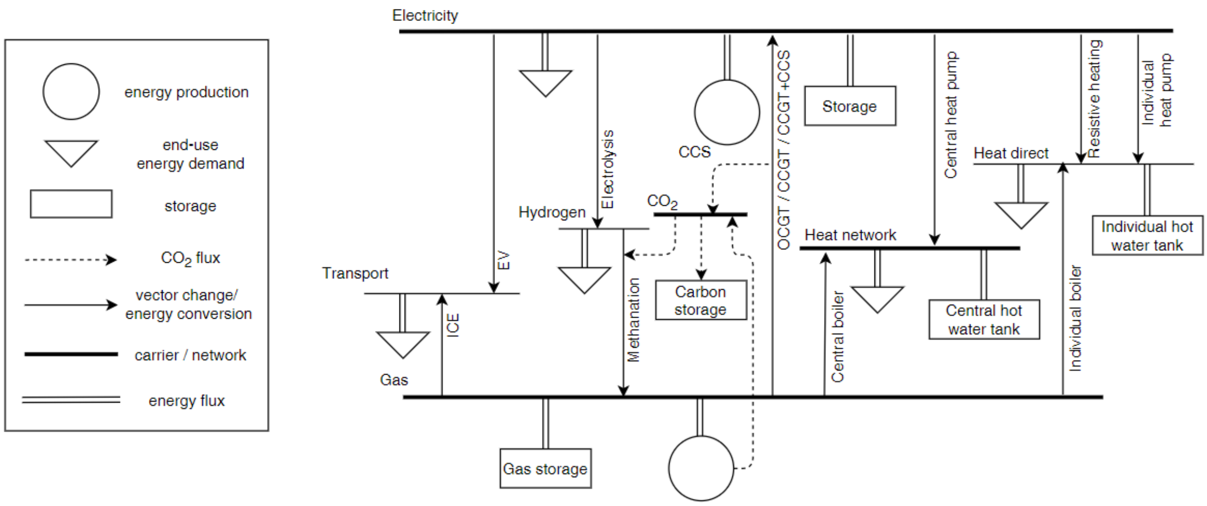

Figure 1. Schematic diagram of the EOLES_mv model; the figure on the right shows the interactions between energy supply, demand, storage and carriers by energy flux and CO_2 exchanges. The box on the left provides the key to the shapes. The two energy supply technologies are electricity and gas production, each connected to its own network.

2.2. Input parameters

2.2.1. VRE profiles

Variable renewable energy (offshore and onshore wind and solar PV) hourly capacity factors were prepared using the renewables.ninja website[1], 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) find 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 electricity transmission system operator (RTE).

In a previous article, we showed that 2006 can be chosen as the representative year for the 2000-2018 period regarding variability of VRE technologies in relation to weather; thus, we use the hourly VRE and hydro-electricity profiles for the year 2006 (Shirizadeh et al, 2019). Appendix 2 provides more information about the methodology used in the preparation of hourly capacity factor profiles of wind and solar power resources.

2.2.2. Energy demand

The energy demand is categorized for each end-use, i.e. electricity, heat, transport and hydrogen (as a substitute for coal in industry) covering all the main energy sectors: residential and tertiary buildings, industry and construction, agriculture and transport. Unlike the existing literature, we define the end-uses and allow the model to make the optimal choice to satisfy demand in different sectors for different end-uses. As an example, the EOLES_mv model optimizes the required transport energy carrier (EV or ICE) for three of the four main transport categories (light and heavy vehicles and buses), while trains are all considered to be electrically powered as they are today. Similarly, EOLES optimizes heat production to satisfy 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

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

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 energy requirement for each energy sector is taken from ADEME's update of the 'Energy climate' scenario for 2050 (ADEME, 2017). While different end-uses are provided in detail for the residential sector, this detail is not included for the tertiary, agriculture and industry sectors. Another future annual demand projection for France is provided by the French National Low Carbon Strategy (DGEC, 2019). The sectorial demands are very similar in these two studies, but the latter provides more detail about energy end-use for the transport and tertiary sectors. Therefore, taking the same values found in ADEME (2017), we use the final energy demand allocation for the 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 '2017-2050 scenario' study (négaWatt, 2017). Therefore, using the same overall energy demand in industry and agriculture provided by ADEME (2017), we use the allocation of heat and electricity demand provided by négaWatt to find the end-use demand for each of these technologies. The preparation of each end-use demand profile is presented in Appendix 3. Table 1 summarizes the assumed annual demand for each sector and its end-use, and the sources of these annual values and hourly profiles.

Table 1. Assumed 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>

2.2.3. Limiting capacity and energy production constraints

We use the 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 the French national open data forum, provided by RTE (French transmission network operator) for each year from 2000 to 2018. By summing the hourly lake-generated hydro-electricity profiles for each month, we calculated the maximum amount of electricity that can be produced from this technology for each month from 2000 to 2018. Similarly, the maximum biogas production from renewable gas[1] production technologies (methanization and pyro-gasification) are taken from the 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 70% of methane and 30% of carbon dioxide, which is used as the green CO_2 for the methanation process.

2.2.4. Economic parameters

Table 2 summarizes the economic parameters (and their sources) of energy supply technologies used as input data in the EOLES model. Since four energy carriers are considered (electricity, gas, hydrogen and heat), 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 are studying the optimal state of the French energy sector for 2050, the economic parameters used are all forecasts for 2050.

Table 2. 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.
*****The overnight cost only accounts for the gasification plants, while the wood used for energy 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 preliminary business studies are, therefore, not included in this period.

[1] 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 using the Sabatier reaction between hydrogen and green CO2) that can be injected directly into the gas network. In its biogas form, it is produced using biochemical processes from organic waste (methanization) and gasification of energy wood and biomass.

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 at 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):

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

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 3. 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 (2016)
Methanation (Power-to-CH4)**	450/700	25/20	86.05	59.25	5***	0.5	0.8/0.79	ENEA (2016)
Resistive	100	20	7.86	2	0	0.5	0.9	Brown et al. (2018b)
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. (2018b)
Decentral gas boiler	175	20	13.76	3.5	0	0.5	0.9	Brown et al. (2018b)

* 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 the Sabatier reaction of green CO_2 as a by-product from methanization with the hydrogen produced, therefore the economic parameters of each production are presented as electrolysis/Sabatier.
***As in Shirizadeh et al. (2020).

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) it is also kW_{th}/kW_e and for Gas-to-Heat technologies (gas heat pump and central and non-central gas boilers) it is 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 4. 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. (2018b)
CTES	0	0.64	40	-	0	0	0.0348	1	90%/75%	Brown et al. (2018b)
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 fee of 2€/MWh_{th} for the gas network is derived from the French energy regulation commission (CRE, 2018).

Table 5 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 which can serve 400 vehicles per day costs €300,000: assuming nearly 100kWh_{th} (384km of autonomy) of charging at each charge, we obtain this cost.

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

2.2.5. 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:

$$annuity_{tec} = \frac{DR \times CAPEX_{tec}((DR \times ct_{tec})+1)}{1-(1+DR)^{-lt_{tec}}} \qquad (2)$$

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.

2.3. The chosen SCC scenarios

The SCC values are based on the official 'value for climate action' social cost of carbon introduced by Quinet et al. (2019) for France for 2050, (between 600€/tCO_2 and 900€/tCO_2). However, the results presented are for a maximum €500/tCO_2 of SCC, since for higher values, we have not observed any significant change in the energy mix or emissions.

3. Results

3.1. Energy mix

Figure 2 shows primary energy production. With no SCC, about 75% of primary energy comes from natural gas. But from an SCC of €100/tCO_2 upwards, the proportion of natural gas in primary energy production more than halves and for an SCC of €200/tCO_2 it is completely abandoned and replaced by increased electrification and bio-methane from methanization. Although introducing an SCC value leads to an increase in the proportion of nuclear power in primary energy production, this never exceeds 25%.

The gas network provides 30% to 75% of primary energy production. Once natural gas is phased out, renewable gas from methanization alone provides 22% of the primary energy supply, and as SCC increases (for 400€/tCO_2 and 500€/tCO_2) pyro-gasification of biomass enters the optimal mix, and the proportion of renewable gas increases to 30% of primary energy production. Starting from an SCC value of 200€/tCO_2, methanization is fully exploited and the upper limit of annual renewable gas production from this technology (152TWh_{th}/year) is reached. Once pyro-gasification enters the optimal mix, it also reaches its upper limit of 77TWh_{th}/year. The only energy supply technologies that are fully exploited are renewable gas production technologies. Installed capacity and annual energy production by primary energy source are presented in Appendix 6.

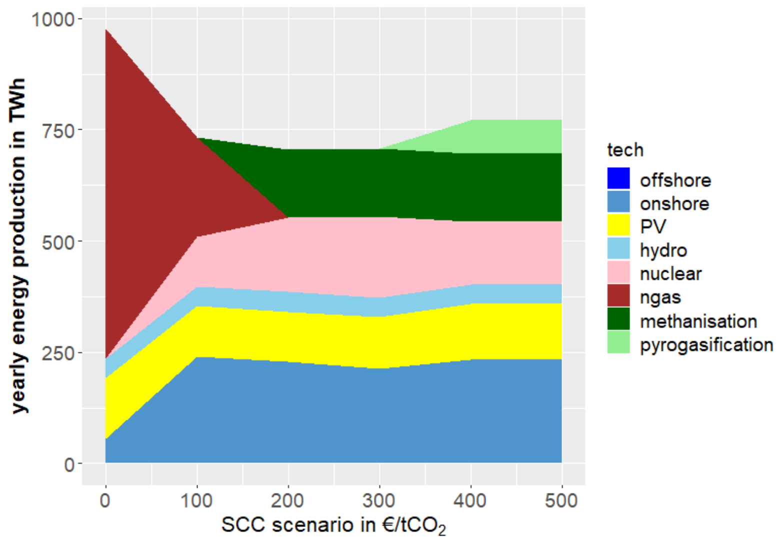

Figure 2. Primary energy production for each SCC scenario

With no SCC, nearly half of the electricity production comes from natural gas (Figure 3). When the SCC value increases, nuclear energy and variable renewables replace natural gas while combined cycled gas turbines (CCGT) without carbon capture units (CCS) are replaced by nuclear power and CCGT equipped with CCS. The proportion of electricity in the primary energy supply increases from 25% to up to 78% as SCC increases, thanks to electrification of the heat sector, replacement of natural gas in electricity production by nuclear power and an increased proportion of power-to-gas.

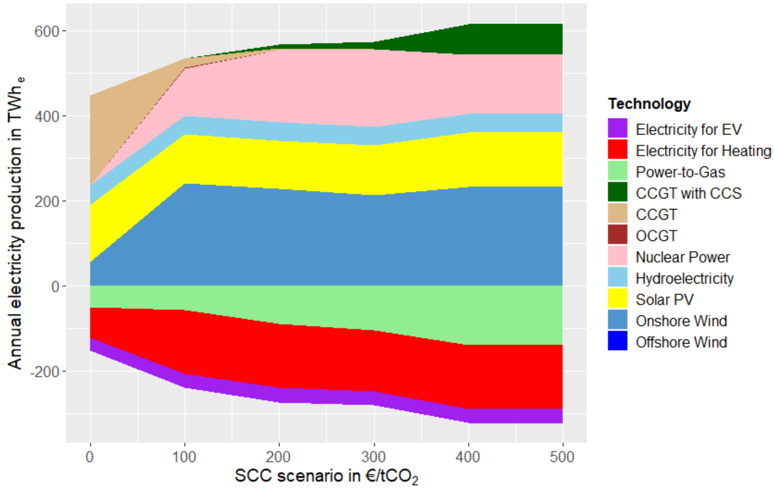

Figure 3. Electricity production (positive) and its conversion to other sectors (negative) in TWh_e/year as a function of SCC

For zero social cost of carbon, natural gas dominates the gas supply side, with a very small proportion of hydrogen for industry (Figure 4). Half of the natural gas is used for electricity production while the other half is used in the heat and transport sectors. As the social cost of carbon increases, gas for electricity production falls tenfold leading to a steep decrease in natural gas production from 740TWh_{th}/year to 220TWh_{th}/year, and for 200€/tCO_2 the gas supply becomes fully decarbonized and biogas from methanization replaces natural gas. While from this SCC value upwards, gas is mainly used for transport, by increasing the SCC value, gas production from pyro-gasification of biomass becomes cost-effective enough to be sent to CCGT power plants fitted with CCS to provide negative carbon-emitting electricity. Power-to-gas, including both methane from methanation and hydrogen from electrolysis, can provide up to 100TWh_{th}/year of synthetic gas. When the renewable gas supply is added, the gas network can account for 330TWh_{th}/year of energy.

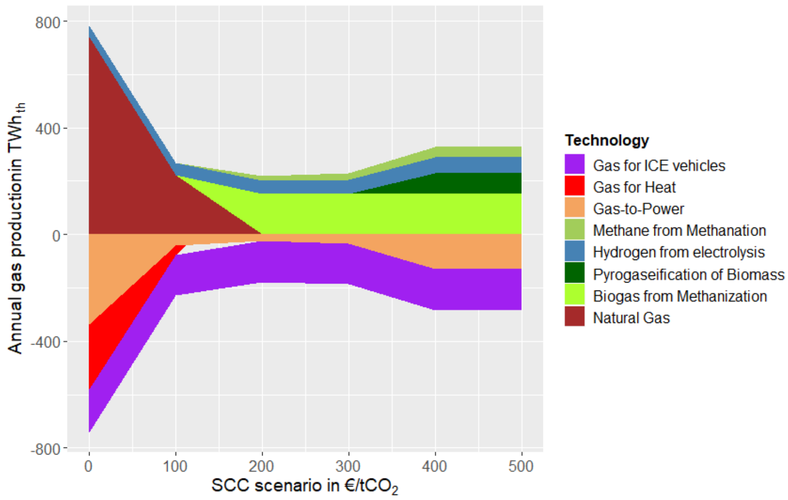

Figure 4. Gas production (positive) and its conversion to other sectors (negative) in TWh_{th}/year as a function of SCC

Figure 5 shows annual heat production as a function of SCC. For zero SCC half of the heat is produced from gas, by increasing the SCC value the proportion of electric heating (resistive and electric heat pumps) increases remarkably (to more than 90% for an SCC of €100/tCO_2), and from an SCC of €200/tCO_2 upwards, heating is fully electrified.

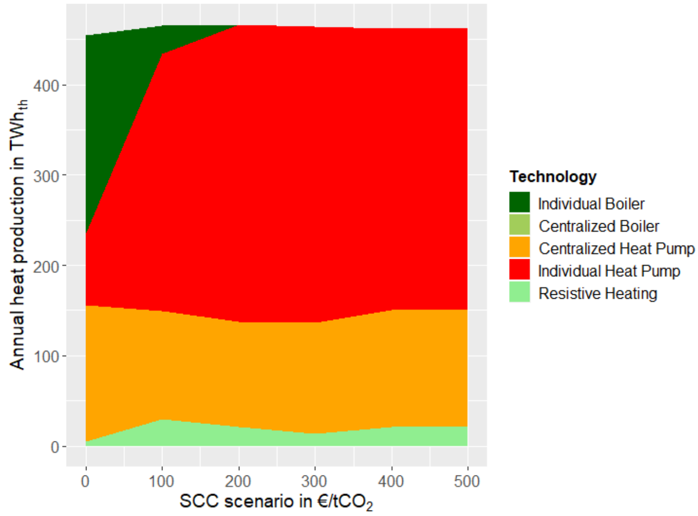

Figure 5. Annual heat production in TWh$_{th}$/year as a function of SCC

Although as the SCC value increases the heat sector becomes more and more electrified (heating, cooking and hot water), the transport sector remains highly dependent on internal combustion engines (ICE) using fossil fuels (for SCCs of 0 and €100/tCO_2) or renewable gas (for SCC of €200/tCO_2 and above) as the energy carrier (Figure 6). All heavy vehicles and buses (public transport except trains) are ICE vehicles, and light vehicles are also mainly fueled by gas (ICE) while the proportion of electric vehicles is very small in the transport sector[1].

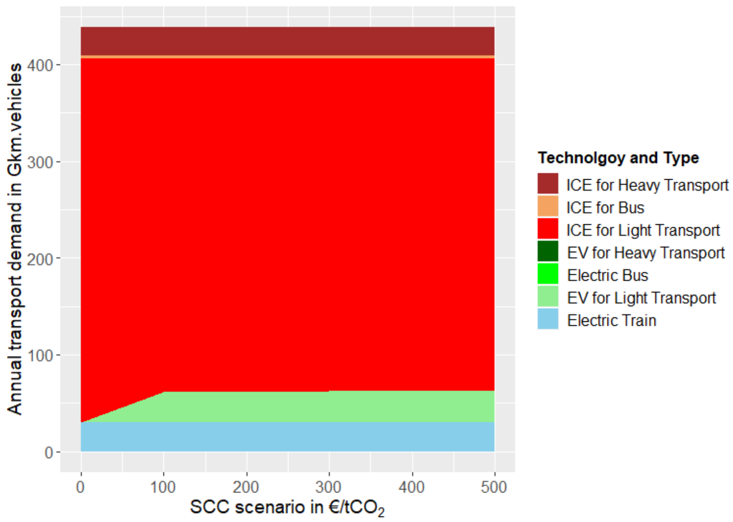

Figure 6. Transport supply by mobility type and vehicle technology type in Gkm.vehicles/year as function of SCC (the rail demand satisfied by electric trains is expressed in TWh$_e$/year

3.2. The economics

We define two different system costs: technical cost (eq. (A.1) in Appendix 1 excluding the last part) and social cost, i.e. the cost including the social cost of carbon (the whole of eq. (A.1)). In the EOLES_mv model, the social cost is optimized while the technical cost is calculated without

[1] A back-of-the-envelope calculation is presented in Appendix 9 to provide an intuitive assessment of the relative cost-optimality of electric vehicles and internal combustion engines.

optimization. In a decentralized equilibrium, the gap between these two costs would include the remuneration of negative CO_2-emitting plant operators and the tax paid by CO_2-emitting sources.

Positive and negative emissions are valued at the same price. Therefore, a carbon neutral system has equal technical and social costs while for a negative emission system the latter is lower. The intersection between the technical and social cost curves is at an SCC of nearly €200/tCO_2 while increasing the SCC value, leading to negative emissions, increases the gap between these two curves to €10.5bn/year (nearly 16% of the technical cost) for an SCC scenario of €500/tCO_2 (Figure 7).

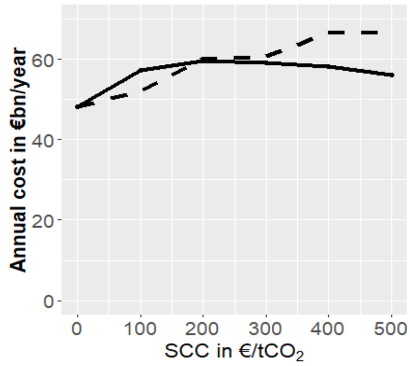

Figure 7. Annual social (including SCC) and technical costs for each SCC scenario; the dashed line represents the technical cost, and the solid line represents the optimized cost including the SCC value

Figure 8 shows the system-wide levelized cost of each energy carrier. With no SCC, the average LCOEs of gas and heat are very low thanks to cheap natural gas with no carbon tax. On increasing the SCC value, the price of gas increases because first the carbon tax equals the cost of fossil gas, and by increasing the SCC value, it is fully replaced by expensive biogas from methanization. Once the SCC is high enough, even more expensive renewable gas from pyro-gasification of biomass enters the optimal mix, increasing the system-wide LCOE of gas (from 400€/tCO_2 upwards). The price of electricity remains nearly stable since power production is mainly from renewable and nuclear sources (for an SCC of €100/tCO_2 and above), and none of these technologies' costs increase as SCC is increased since they are considered to be carbon-neutral. Thanks to the electrification of heat production, the price of heat also remains stable once it is fully electrified, i.e. from an SCC of €200/tCO_2 upwards.

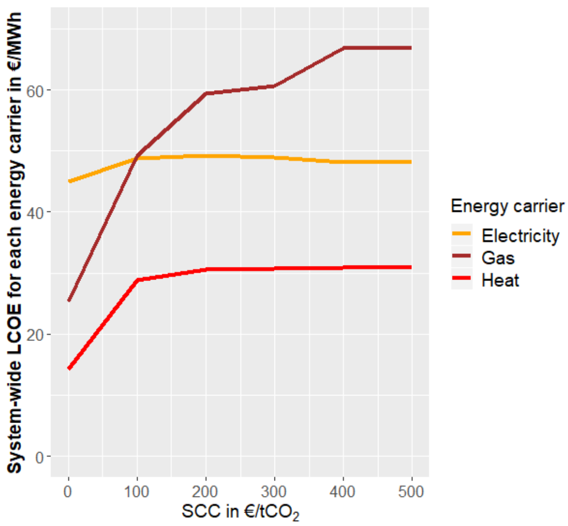

Figure 8. Average system-wide levelized cost of energy for each energy carrier in €/MWh$_e$ for electricity and €/MWh$_{th}$ for gas and heat

3.3. Availability of different low-carbon technologies

In order to study the importance of each energy production technology, four alternative availability scenarios are studied: without nuclear (noEPR), without CCS (noCCS), without renewable gas (noRG) and without variable renewable electricity (noVRE). The overall CO_2 emissions and the overall energy supply-side cost are compared to evaluate their relative importance (Figure 9).

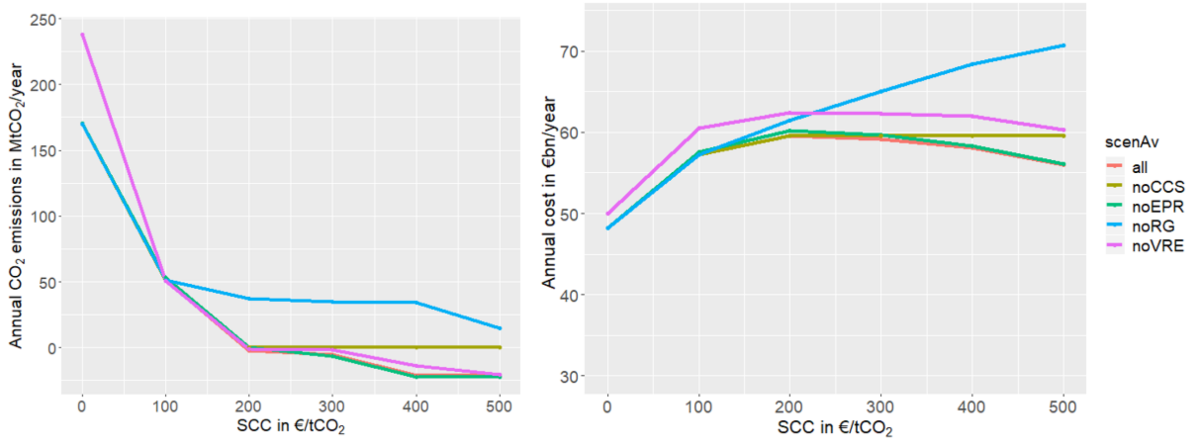

Figure 9. Annual CO2 emissions (left) and the annual social cost (right) of the energy system for different technology availability scenarios

When all the technologies are available the energy system emits 170MtCO_2/year for zero SCC[1]. The introduction of an SCC leads to an efficient emission reduction: 51.1MtCO_2/year of CO_2 emissions for an SCC value of €100/tCO_2, and -2.4MtCO_2/year for an SCC of €200/tCO_2. Increasing the SCC value results in negative emissions, up to 21MtCO_2/year of captured and stored CO_2 for an SCC of €500/tCO_2.

While having all options available is by definition the optimal case, for all the availability scenarios including renewable gas, the energy system reaches carbon neutrality for an SCC of €200/tCO_2. For zero SCC, VRE technologies can help reduce emissions, but as the SCC value increases, the annual CO_2 emissions of the scenario with no VRE technologies becomes nearly the same for the scenario with all the technologies available. Similarly, the scenario with no nuclear power leads to the same CO_2 emissions as the scenario where all the technologies are available.

Since the only negative emission technology considered is CCS combined with CCGT power plants, the scenarios excluding CCS do not reach negative emissions, and their emissions stay zero from €200/tCO_2 upwards. On the other hand, achieving carbon neutrality requires the replacement of fossil gas by renewable gas, and carbon neutrality cannot be achieved without renewable gas since fossil gas with CCS will still produce residual emissions. Therefore, for an efficient emission reduction target, renewable gas and CCS technologies are of greater importance than VRE and nuclear power technologies, which are substitutable with respect to their emission reduction potential. The primary energy production and the energy mix of each end-use demand are presented in Appendix 8.

The exclusion of both renewable gas and VRE technologies leads to the highest cost increases among different technology availability scenarios (Figure 9 – right). The scenario with no nuclear power has nearly the same cost as the scenario with all technologies available (a difference of less than 1% of the energy system cost for any SCC value), which means that the economic benefit of nuclear power is negligible. On the other hand, the availability of VRE technologies can reduce the social cost of the

[1] Current French CO_2 emissions are around 420MtCO_2/year. The reason for this big difference in the absence of a SCC value is explained in Appendix 6.

energy system by up to 6% and renewable gas can reduce it by up to 20%. While both CCS and renewable technologies are of key importance, nuclear energy does not play an important role, either in achieving low emissions, or in decreasing the system cost.

3.4. How high should the social cost of carbon be to ensure carbon-neutrality?

For all the availability scenarios including renewable gas, an SCC of €200/tCO_2 can be enough to completely decarbonize the energy sector (Figure 9 – left). The impact of some other uncertain hypotheses such as the cost of emerging technologies, the level of final energy demand and the development of the heat network should be studied in order to assess the robustness of the proposed SCC.

To study a possible wide variation in the future cost of key emerging technologies, we varied the cost of variable renewable electricity, renewable gas supply, nuclear power, Li-Ion batteries (for both stationary use and electric vehicles) and natural gas supply by +/-50% from the central cost scenario (presented in Tables 2, 3, 4 and 5). Figure 10 shows a) the annualized total cost and b) annual CO_2 emissions of the energy system for SCC values of €200/tCO_2 and €300/tCO_2.

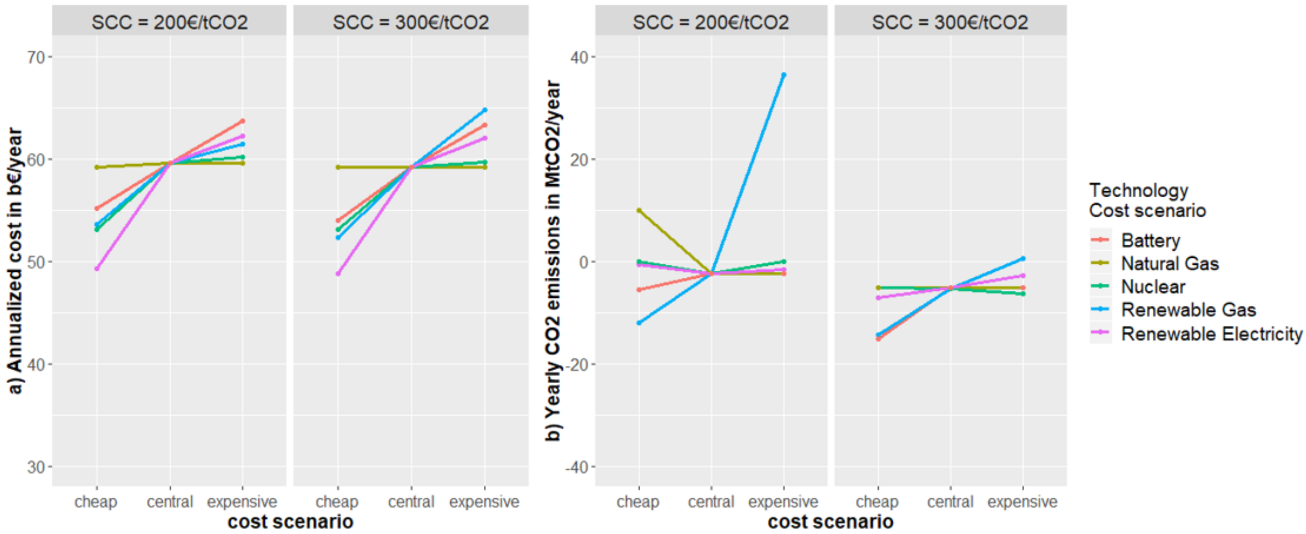

Figure 10. Sensitivity of (a) the yearly total cost and (b) the emissions of the energy system to a +/-50% cost variation in battery (for both stationary and electric vehicles), fossil gas, nuclear energy, renewable gas and variable renewable electricity technologies

While fossil gas has no impact on system cost, the cheap technology cost scenario for batteries, nuclear power and renewable gas and electricity can reduce the system cost by up to 11%. However, increasing the cost of key technologies has a smaller impact on overall cost. From the emissions point of view (Figure 10.b), while for an SCC value of €200/tCO_2 the energy system can be positively CO_2-emitting for both cheap fossil gas and expensive renewable gas scenarios, for an SCC of €300/tCO_2 whatever the cost scenario, the energy system is either carbon-neutral or provides negative emissions.

The central demand scenario in this study is ADEME's update of the energy climate scenario, with a final energy demand of 82Mtoe/year. To assess the impact of energy demand on decarbonization, we define a high demand scenario equal to the actual final energy demand (142Mtoe/year).

The system-wide levelized costs of energy carriers do not vary with, and remain nearly robust to, the energy demand level (Figure 11.a). For an SCC of 200€/tCO_2 energy system emissions vary from 2.4MtCO_2/year to 1.5MtCO_2/year which is a minor variation while for the high SCC of €300/tCO_2, even for the high energy demand scenario, the energy system provides negative emissions (Figure 11-b).

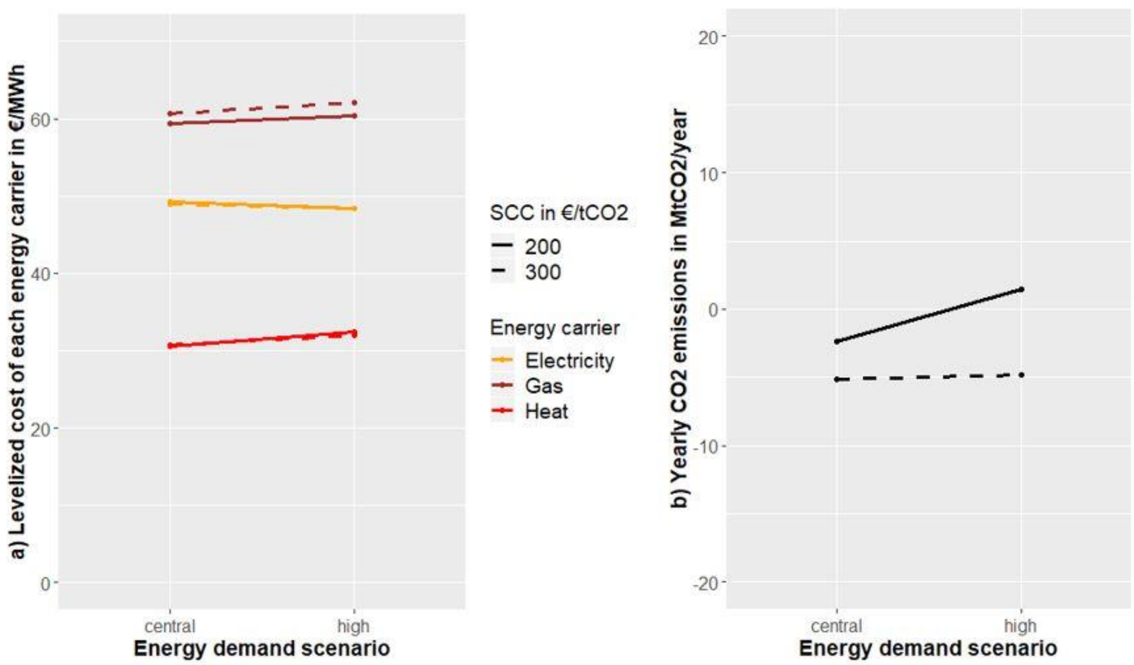

Figure 11. Sensitivity of (a) levelized cost of each energy carrier and (b) emissions of the energy system to the demand scenario as a function of two chosen social cost of carbon scenarios (the high scenario accounts for the current energy demand of France and the central scenario accounts for the future energy demand projection by the French Ministry of Ecological Transition and Solidarity)

To sum up, an SCC of 300€/tCO_2 will be enough to decarbonize the energy system considering different technology costs and uncertainties in energy demand and heat network coverage[1]. The Sankey flow diagrams for the central availability scenario and the scenario without nuclear energy for the proposed robust SCC of €300/tCO_2 are presented in Appendices 11 and 12.

4. Discussion

4.1. Comparison with existing scenarios

The second "French national low carbon strategy" (SNBC, 2018) proposes very high electrification of the transport and heating sectors. The high efficiency improvements in the residential and tertiary sectors and modal change strategies in the transport sector, as well as the elimination of coal from industry are the main enablers of the French energy transition in this scenario. Similarly, ADEME's update of the "energy-climate scenario 2035-2050" study (ADEME, 2017) shows an energy mix consisting of 49% to 69% renewable energies with the remainder from conventional energy resources. According to this scenario, 39% of final energy consumption is satisfied by the electricity network, 24% by the gas network, 8% by the heat network and 24% from direct use of renewable energies such as biomass.

According to the "négaWatt scenario" (négaWatt, 2017), 35% of final energy consumption is provided by the electricity network, 36% by the gas network and 7% by the heat network. The remaining 22% consists of solid and liquid fuel. In the final energy mix of this scenario no conventional energy production technology appears (oil, coal, fossil gas and nuclear energy). According to both SNBC and

[1] The importance of heat network coverage limitations has also been studied using an uncertainty range of 50%, and no change was observed in cost or emission levels. Appendix 10 shows the findings of the study of sensitivity to heat network coverage.

ADEME, the transport sector will be highly electrified, while négaWatt suggests a less electrified transport sector.

By making the choice of energy carrier endogenous for different end-uses we conclude that in optimal scenarios, the energy system will be highly electrified. More than 70% of a carbon neutral energy system's primary energy production comes from electricity. The transport sector is presented as a highly electrified sector in the ADEME and SNBC scenarios. Our findings show that even for very high SCC scenarios, the transport sector remains highly dependent to internal combustion engines, with an insignificant proportion of electric vehicles in the final transport demand. Only two to three million light vehicles are found to be electric, which contrasts strongly with both SNBC (2018) and ADEME (2017). This result is very close to négaWatt's scenario which suggests 15.7% of electrification in the transport sector.

Sector-coupling can accelerate the decarbonization of the energy sector and decrease the costs and load curtailment providing additional flexibility (Brown et al, 2018b, Victoria et al, 2019, BNEF 2020 and Pavičević et al, 2020). Our findings, which agree with this conclusion, highlight the importance of full endogeneity in energy carrier choice including the key representative technologies that make this choice possible. Brown et al. (2018b) show that with no commercial power exchange with neighboring countries, more than 80% of France's primary energy consumption is satisfied by VRE resources, and only about 5% of this primary energy is provided by fossil gas. This study excludes renewable gas as a possible energy supply option. While our findings for SCC values of €200/tCO_2 and above are very close to these results, fossil gas is abandoned at these SCC values. Our findings show that in an optimal case a significant proportion of future transport demand is met by gas-powered internal combustion engines, and a very small proportion by electric vehicles. In a scenario where electric vehicles alone satisfy transport demand, and fossil gas alone is available as a gas production option, the proportion of gas in the final energy demand would be less.

4.2. The cost of carbon-neutrality

A nearly carbon-neutral energy system requires an SCC of 200€/tCO_2 and accounting for uncertainties related to energy demand and technology cost development, it requires an SCC of 300€/tCO_2. The technical costs of the optimal energy system for these SCC values are €60.04bn/year and €60.69bn/year respectively. In the absence of an SCC value, the optimal energy system costs €48.19bn/year. The difference between the cost of a carbon-neutral energy system and one without SCC is between €11.85bn/year and €12.50bn/year. France's gross domestic product (GDP) was €2,332.68bn/year in 2019[1]. Assuming an average increase in GDP of 1%/year, in 2050 France's GDP would be €3,175.54bn/year. The 2050 energy system for zero SCC would cost 1.5% of this estimated annual GDP. Considering the technical cost of a decarbonized national energy system for SCC values of €200/tCO_2 and €300/tCO_2, decarbonization would cost between 0.37% and 0.39% of France's estimated GDP for 2050. Therefore, the contribution of the energy sector to France's national GDP will have to increase by roughly 25% in order to achieve carbon-neutrality.

4.3. The role of renewable gas

Our findings show that while the proportion of renewable gas does not exceed that of renewable electricity in primary energy production, it is of the greatest importance. In the absence of renewable gas, the energy system cannot achieve carbon neutrality even for a high SCC value of €500/tCO_2. Moreover, sensitivity analysis also confirms this key role of renewable gas in both cost optimality and emission reduction. Although our findings imply that renewable gas is of key importance in achieving

[1] https://tradingeconomics.com/france/gdp

carbon-neutrality for the lowest cost, using the existing gas infrastructure for biogas transmission and distribution might lead to methane leakage (Alvarez et al, 2012), eroding all the associated climate benefits (Union of concerned scientists, 2017). Similarly, particulate pollution by gas-fueled ICE vehicles has been highlighted as an important environmental disadvantage of this transport technology (Suarez-Bertoa et al, 2019). Therefore, it is essential to limit methane leakage and particulate pollution and take them into account correctly in environmental impact assessments.

In this study, we chose gas-fueled ICE as a representative technology for all ICE vehicles (fueled with biofuels and liquefied biogas), since they have similar economic characteristics and the main difference between them would be the relative cost of these fuels. Therefore, the idea of gas being the carrier for transport fuel can be expanded to include biofuels and liquefied biogas. The high relative proportion of ICE vehicles in the transport sector is confirmed by the results of several integrated assessment models (Yeh et al, 2017). However, the environmental damage caused by biofuel production and its high energy demand, as well as the competition between biofuels and food crops (due to land-use changes caused by biofuel production) are highly debated topics casting doubt on scenarios that include liquid biofuels (Kleiner, 2008, Searchinger et al, 2008, Lapola et al, 2010 and Rulli et al, 2016).

4.4. Negative emissions

From the SCC of €200/tCO_2 upwards, the energy system can provide negative emissions, and for an SCC of €500/tCO_2 the negative emissions reach 21MtCO_2/year. In the second French national low carbon strategy report, the residual emissions for France are evaluated to be more than 80MtCO_{2eq}/year (Mainly because of agriculture and land-use), assuming no negative emissions (SNBC, 2018). These emissions are not covered by the EOLES_mv model but negative emissions from the energy sector could be one of the compensation options to help achieve net zero emissions by 2050. Thus, although from an energy-only modelling perspective achieving carbon-neutrality does not necessarily require carbon capture and storage, in order to deal with the residual emissions, carbon capture and storage combined with bio-energies represent a pivotal mitigation option as stated in the IPCC's *Special Report on 1.5°C of Global Warming* (IPCC, 2018) and in the IEA's *Special Report on Carbon Capture, Utilisation and Storage* (IEA, 2020).

4.5. Limits and further research

In this paper, we have considered France in isolation which means there is no exchange of energy between France and its neighboring countries (except natural gas imports). Several findings of this study might be different in a highly inter-connected European energy system. For example, renewable gas can play an important role in balancing wind fluctuations, but inter-connections with neighboring countries can also help balance intermittent power production technologies. Therefore, the role of renewable gas would be less important, at least in the electricity sector. On the other hand, we consider only anaerobic digestion of organic waste and pyro-gasification of wood and biomass as sources of bio-energy, which would only be used by injection into the gas network to satisfy either transport, heating or electricity final end-uses. Renewable gas can also be used as a raw material in several industries, and its by-products also have an economic value. Thus, a more detailed analysis of the whole bio-methane value chain considering different production and end-use options could be the next step in evaluating the importance of renewable gas in a carbon-neutral energy system. However, as explained in section 4.3, methane leakage and particulate pollution resulting from the increased use of renewable gas in the energy sector could erode all the assumed benefits. The direct and indirect environmental impacts of renewable gas production, distribution and consumption need further analysis.

In this study, we used inelastic end-use demand profiles. The energy demand scenario from the French low-carbon strategy that we used is based on significant efforts being made to achieve energy efficiency and a modal shift in different sectors. Although these assumptions may be realistic for high SCC values, the situation will be very different for low SCC values (especially 0€/tCO_2 and 100€/tCO_2), leading to different final energy demand levels and profiles in different sectors. By including the option of weekly charging for EVs and ICE vehicles, we accounted for the elasticity of weekly charging profiles in the transport sector, but the energy demand profiles of other sectors are all inelastic in EOLES_mv. Therefore, the energy demand profiles and the annual end-use demand levels should be different for different SCC values not only in the transport sector, but in all other energy sectors. Inclusion of this elasticity in the energy system modelling, although very challenging, would lead to energy demand profiles that are better adapted to the intermittent energy supply technologies, leading to lower energy system costs.

Conclusion and policy implications

This article studies the cost-optimal low-CO_2 energy mix, relative role of energy carriers and different low-carbon options applied to the case of France for the year 2050. To that end, we have developed a first-of-its-kind integrated optimization of the energy system model (EOLES_mv). We allowed the end-use demand for each major energy sector to choose endogenously among four different energy carriers (electricity, heat, gas and hydrogen), we maintained high temporal resolution, and we studied different availability and future cost development scenarios for the key low-carbon technologies as a function of SCC.

Our results imply that the optimal carbon-neutral energy system is highly electrified (exceeding 70% of the primary energy supply), but that non-fossil gas, even though accounting for a smaller proportion of energy supply, plays a very important role in emission reductions. In the presence of renewable gas, a carbon-neutral energy sector can be achieved for an SCC of €200/tCO_2, while for high energy demand or unfavorable conditions in the future cost reduction of renewable gas, carbon neutrality can be achieved for an SCC of €300/tCO_2. In cases where non-fossil gas is not available, carbon-neutrality cannot be achieved even for the very high SCC scenario of 500€/tCO_2.

Renewable electricity and gas technologies play a crucial role in achieving carbon-neutrality, and their absence from the energy supply side can lead to high inefficiencies in cost-optimality and emission reductions for future energy systems. On the other hand, exclusion of nuclear energy from the energy supply side has a minor impact on both emission reduction and cost-optimality. Therefore, one important policy-related outcome of this study is to invest in renewable gas and variable renewable electricity production technologies, and to prioritize them over other low-carbon options, particularly nuclear energy.

Finally, unlike the existing literature, our results suggest that, in a cost-optimal coupled energy system, electricity would satisfy the demand for heat while gas would satisfy that for transport. Therefore, this study suggests that further development of gas charging stations is required, as well as individual and central heat pumps.

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Appendices

Appendix 1. EOLES_mv model

A.1.1. Sets and parameters

Table A.1 presents the sets and indices of the EOLES_mv model and table A.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 A. 1 Sets and indices of the EOLES_mv model

Index	Set	Description
h	$\in$ H	**Hour:** the number of hours in a year, from 0 to 8759
d	$\in$ D	**Day:** The number of days in a year, from 1 to 365
w	$\in$ W	**Week:** The number of weeks in a year, from 1 to 52 (the 52[nd] week accounts for 10 days)
m	$\in$ M	**Month:** the twelve months, from January to December
tec	$\in$ 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	$\in$ GEN $\subseteq$ TEC	**Generation:** Energy supply technologies (floating offshore, monopile offshore, onshore, PV, river, lake, nuclear, natural gas, methanization and pyro-gasification)
$elec$	$\in$ ELEC $\subseteq$ 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	$\in$ GAS $\subseteq$ TEC	**Gas:** The technologies providing gas by supply, conversion or storage (natural gas, methanization, pyro-gasification, electrolysis, methanation and gas storage)
$heat$	$\in$ HEAT $\subseteq$ 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)
$transport$	$\in$ TRANSPORT $\subseteq$ 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}	$\in$ ELECGEN $\subseteq$ ELEC	**Electricity supply:** The technologies generating electricity (floating offshore, monopile offshore, onshore, PV, river, lake and nuclear)
gen_{gas}	$\in$ GASGEN $\subseteq$ GAS	**Gas supply:** Technologies supplying gas (natural gas, methanization and pyro-gasification)
$biogas_{gas}$	$\in$ BIOGAS $\subseteq$ GAS	**Renewable gas:** biogas supply technologies (methanization and pyro-gasification)
vre	$\in$ VRE $\subseteq$ ELEC	**VRE:** variable renewable electricity generation technologies (offshore, onshore, PV and run-of-river)
str	$\in$ STR $\subseteq$ TEC	**Storage:** energy storage technologies (PHS, battery, gas storage, individual thermal energy storage and central thermal energy storage)
str_{elec}	$\in$ STRELEC $\subseteq$ ELEC	**Electric storage:** technologies providing storage for electricity (battery and PHS)
str_{gas}	$\in$ STRGAS $\subseteq$ 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 A. 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

A.1.2. Variables

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

table A. 3 Variables of EOLES_mv model

Variable	**Unit**	**Description**
$G_{tec,h}$	GWh	Hourly energy generation by technology
Q_{tec}	GW	Installed capacity by technology
$STORAGE_{str,h}$	GWh	Hourly energy entering each storage technology (inflow)
$SOC_{str,h}$	GWh	Hourly state of charge of each storage technology (stock)
S_{str}	GW	Installed charging capacity by storage technology
$CONVERT_{conv,h}$	GWh	Hourly converted energy by each conversion technology
$CHARGE_{transport,h}$	GWh	Hourly charging of each transport technology
$RESERVOIR_{transport}$	GWh	The energy reservoir volume for each transport technology
$VOLUME_{str}$	GWh	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 energy system cost annualized (minus the investment cost of already installed capacities). This is the objective function to be minimized.

A.1.3. Equations

A.1.3.1. Objective function

The objective function, shown in Equation (A.1), is the sum of all costs over the chosen period, including the annualized investment costs as well as the fixed and variable O&M costs. For some storage options, another CAPEX-related cost proportional to the energy capacity in $€/kWh$ is accounted for ($annuity_{str}^{en}$).

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

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.

A.1.3.2. 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 A.2, A.3, A.4, A.5a-d and A.6).

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

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

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

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

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

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

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

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

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 A.6) beside other adequacy equations.

A.1.3.3. 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 A.7).

$$G_{vre,h} = Q_{vre} \times cf_{vre,h} \quad \text{(A.7)}$$

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.

A.1.3.4. 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 A.8):

$$SOC_{str,h+1} = SOC_{str,h} + (STORAGE_{str,h} \times \eta_{str}^{in}) - \left(\frac{G_{str,h}}{\eta_{str}^{out}}\right) \quad \text{(A.8)}$$

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.

A.1.3.5. 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 (A.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:

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

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, $\delta_{variation}^{load}$ is the load variation factor and $\delta_{uncertainty}^{load}$ 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).

A.1.3.6. Energy-generation-related constraints

The relationship between hourly-generated energy and installed capacity can be calculated using equation (A.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.

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

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 (A.11).

$$Q_{frr} \geq G_{frr,h} + RSV_{frr,h} \qquad \text{(A.11)}$$

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

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

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.

A.1.3.7. Energy conversion

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

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

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.

A.1.3.8. Charging of transport technologies

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

$$CHARGE_{transport,h} = profile_h^{transport} \times Q_{transport} \quad \text{(A.14)}$$

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 $transport$.

We consider 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 (A.5a-d) and the charging profiles should be applied to account for the charging behavior of different transport technologies from equation (A.14). We define equation (A.15) to keep both charging and demand constraints above and to let the vehicles choose the day of charging during the week;

$$\sum_{h \in w} CHARGE_{transport,h} = \sum_{h \in w} G_{transport,h} \quad \text{(A.15)}$$

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, we define the reservoir size (storage volume) for each transport technology (equation A.16).

$$\sum_{h \in w} CHARGE_{transport,h} \leq RESERVOIR_{transport} \quad \text{(A.16)}$$

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

A.1.3.9. 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 for the demand in different locations, which require a heat network. Equation (A.17) separates the central heating technologies and define a heat network capacity for the distribution of produced heat;

$$Q_{heat-net} \geq Q_{central} \quad \text{(A.17)}$$

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);

$$G_{heat-net,h} = \sum_{central} G_{central,h} \qquad \text{(A.18)}$$

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.

A.1.3.10. Operational constraints of conversion technologies

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

$$\sum_h G_{ocgt,h} \leq Q_{ocgt} \times cf_{ocgt} \times 8760 \quad \text{(A.19)}$$

$$\sum_h G_{ccgt,h} \leq Q_{ccgt} \times cf_{ccgt} \times 8760 \quad \text{(A.20)}$$

$$\sum_h G_{ccgt-ccs,h} \leq Q_{ccgt-ccs} \times cf_{ccgt-ccs} \times 8760 \quad \text{(A.21)}$$

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 (A.22), (A.23) and (A.24) limit the hydrogen in 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;

$$G_{electrolysis,h} \leq \tau^{hydrogen} \times SOC_{gastank,h} + demand_{hydrogen,h} \qquad \text{(A.22)}$$

$$G_{electrolysis,h} \leq \tau^{hydrogen} \times \sum_{gas} G_{gas,h} + demand_{hydrogen,h} \qquad \text{(A.23)}$$

$$\sum_h G_{electrolysis,h} \leq \tau^{hydrogen} \times \sum_{gas \neq gastank,h} G_{gas,h} + \sum_h demand_{hydrogen,h} \qquad \text{(A.24)}$$

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 (A.22) limits the relative share of hydrogen to other gas options in the storage infrastructures and equation (A.23) limits the relative share of hydrogen in the gas network. Equation (A.24) makes sure that the overall hydrogen that is produced is not more than the capacity of the gas network.

A.1.3.11. 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 (A.25) and (A.26) limit the power production of nuclear power plants with these ramping constraints:

$$G_{nuc,h+1} + RSV_{nuc,h+1} \leq G_{nuc,h} + r_{nuc}^{up} \times Q_{nuc} \qquad \text{(A.25)}$$

$$G_{nuc,h+1} \geq G_{nuc,h}(1 - r_{nuc}^{down}) \qquad \text{(A.26)}$$

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 (A.27) quantifies this limitation:

$$\sum_h G_{nuc,h} \leq Q_{nuc} \times cf_{nuc} \times 8760 \qquad \text{(A.27)}$$

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

A.1.3.12. 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 constraint to ensure the replacement of the consumed stored energy in every storage option (equation A.28):

$$SOC_{str,0} = SOC_{str,8759} + (STORAGE_{str,8759} \times \eta_{str}^{in}) - (\frac{G_{str,8759}}{\eta_{str}^{out}}) \qquad \text{(A.28)}$$

While equations (A.8) and (A.26) 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 A.29):

$$SOC_{str,h} \leq VOLUME_{str} \qquad \text{(A.29)}$$

Equation (A.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.

$$SOC_{str,h} \leq S_{str} \leq Q_{str} \qquad \text{(A.30)}$$

A.1.3.13. Resource availability related constraints

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 (A.31) where q_{tec}^{max} is this capacity limit:

$$Q_{tec} \leq q_{tec}^{max} \qquad \text{(A.31)}$$

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

$$\sum_{h=0}^{8759} G_{biogas,h} \leq g_{biogas}^{max} \qquad \text{(A.32)}$$

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 (A.33):

$$\sum_{h=0}^{8759} CONVERT_{methanation,h} \leq \sum_{h=0}^{8759} G_{methanization,h} \times \gamma_{methanization}^{CO_2} \qquad \text{(A.33)}$$

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 (A.34) limits the captured CO_2 to the available offshore and onshore storage formations;

$$\varphi_{CO_2}^{max} \geq \sum_h G_{ccgt-ccs,h} \times \tau_{ccgt-ccs} \times e_{ccgt} \qquad \text{(A.34)}$$

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).

Appendix 2. VRE profiles

The wind power hourly capacity factor profiles found in the renewables.ninja website are prepared in four stages:

a) Raw data selection; using NASA's MERRA-2 data reanalysis with a spatial resolution of 60km×70km provided by Rienecker et al. (2011),
b) Downscaling the wind speeds to the wind farms; by interpolating the specific geographic coordinates of each wind farm using LOESS regression,
c) Calculation of hub height wind speed; by extrapolating the wind speed in available altitudes (2, 10 and 50 meters) to the hub height of the wind turbines using the logarithmic profile law,
d) Power conversion; using the primary data from Pierrot (2018), the power curves are built (with respect to the chosen wind turbine) and smoothed to represent a farm of several geographically dispersed turbines using a Gaussian filter.

The solar power hourly capacity factor profiles in the renewables.ninja website are prepared in three stages:

a) Raw data calculation and treatment; using NASA's MERRA data with a spatial resolution of 50km×50km. The diffuse irradiance fraction is estimated using the Bayesian statistical analysis introduced by Lauret et al. (2013) and the global irradiation is calculated for an inclined plane. The temperature is given at 2m altitude by the MERRA data set.
b) Downscaling of solar radiation to farm level; values are linearly interpolated from grid cells to the given coordinates.
c) Power conversion model; Power output of a panel is calculated using Huld et al. (2010)'s relative PV performance model which gives temperature-dependent panel efficiency curves.

We first extracted the hourly VRE profiles for each of the 95 counties of France from 2000 to 2018. Then considering the near optimal assumption of proportional installation of new plants to the existing plants, we aggregated these 95 counties 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, we first identified all the existing offshore projects around France using the "4C offshore" website[1], 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.

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

Appendix 3. Demand profiles preparation

A3.1. 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 et al (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[1]), 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.

A3.2. 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[2]. Using daily, monthly and annual correction factors, we maintained the annual transport demand projected by ADEME (2017) and DGEC (2019) scenarios in vehicle-kilometers.

A3.3. 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 423 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.

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

[2] 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.

A3.4. 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 instead of coal, we consider hydrogen. The annual hydrogen demand is divided by 8760 (number of time-slices in in year) to produce a flat demand profile for hydrogen.

A3.5. 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.

Appendix 4. Model parametrization

Equations (A.19), (A.20), (A.21), (A.25), (A.26), (A.27) and (A.33) need technology-related input parameters. These parameters such as ramp rate, annual maximal capacity factor (availability limits due to maintenance) and the limiting factors of different processes need to be introduced into the model. Similarly, equation (A.9), the reserve requirement definition, consists of several input parameters relating the required secondary reserves to installed capacities of VRE technologies and hourly demand profiles. Natural gas with CCS is not a zero-emission technology and according to JRC (2014), it captures only 86% of the carbon dioxide produced by the combustion, thus leaving residual emissions. The values of these input parameters, as well as their sources are presented in Table A.4.

It is worth to mention that according to Agora energiewende (2017), the ramping rates (both upward and downward) for OCGT and CCGT power plants can go easily 100% in less than an hour. While CCGT power plants show enough flexibility in hourly scales, the addition of carbon capture units to these power plants can decrease their flexibility. Nevertheless, according to Mac Dowell et al. (2016) the CCGT power plants equipped with CCS units have enough flexibility to reach to ramping rates as high as the full load power in less than one hour. Therefore, we consider full hourly-flexible operations for both OCGT and CCS-equipped CCGT power plants.

table A. 4 Technical parameters of the model

parameter	definition	value	source
$\boldsymbol{cf_{ocgt}}$	Annual maximal capacity factor of OCGT	90%	JRC (2014)
$\boldsymbol{cf_{ccgt}}$	Annual maximal capacity factor of CCGT	85%	JRC (2014)
$\boldsymbol{cf_{nuc}}$	Annual maximal capacity factor of nuclear plants	90%	JRC (2017)
$\boldsymbol{r_{nuc}^{up}}$	Hourly ramping up rate of nuclear plants	50%	NEA (2011)
$\boldsymbol{r_{nuc}^{down}}$	Hourly ramping down rate of nuclear plants	50%	NEA (2011)
$\boldsymbol{\varepsilon_{offshore}}$	Additional FRR requirement for offshore wind	0.027	Perrier (2018)
$\boldsymbol{\varepsilon_{onshore}}$	Additional FRR requirement for onshore wind	0.027	Perrier (2018)
$\boldsymbol{\varepsilon_{PV}}$	Additional FRR requirement for solar PV	0.038	Perrier (2018)
$\boldsymbol{\delta_{variation}^{load}}$	Load variation factor	0.1	Van Stiphout et al (2017)
$\boldsymbol{\delta_{uncertainty}^{load}}$	Load uncertainty because of demand forecast error	0.01	Van Stiphout et al (2017)
$\boldsymbol{\tau_{ccgt-ccs}}$	The capture rate of CCS	86%	JRC (2014)
$\boldsymbol{\gamma_{methanization}^{CO_2}}$	The relative share of CO_2 to methane in methanization process	3/7	ADEME (2018b)
$\boldsymbol{e_{ccgt}}$	The specific emission of CCGT power plant with natural gas	$340tCO_2/GWh_e$	JRC (2014)
$\boldsymbol{e_{ocgt}}$	The specific emission of OCGT power plant with natural gas	$510tCO_2/GWh_e$	JRC (2014)

Equations (A.7), (A.12), (A.14), (A.22), (A.23), (A.24), (A.31), (A.32) and (A.34) also have some input parameters with respect to the chosen country. These parameters are the maximal available energy from the constrained technologies, maximum available capacities and hourly and monthly profiles of hydro-electricity and variable renewable energy technologies. In this paper we study the French energy sector, therefore we use the values provided for France. Table A.5 summarizes these values and their resources.

table A. 5 Country-specific limiting input parameters of model

parameter	definition	value	source
$lake_m$*	Monthly maximum electricity from dams & reservoirs	See GitHub[1]	RTE (online)
$cf_{vre,h}$**	Hourly power production profiles for VRE technologies (floating and monopole offshore wind power, onshore win power, solar PV and run-of-river)	See GitHub[2]	Renewables.ninja & RTE (online)
g_{biogas}^{max}	Annual maximal biogas production from methanization and pyro-gasification	Methanization: 152TWh$_{th}$ Pyro-gasification: 122TWh$_{th}$	ADEME (2018b)
q_{tec}^{max}	Maximum installable capacity limit for each technology	See GitHub[3]	ADEME (2018a)
$profile_h^{transport}$	Hourly charging profiles for each transport category for each engine type (EV or ICE)	See Github[4]	Doudard (2018)
$\tau^{hydrogen}$	Maximal energy share of hydrogen that can be hosted in French gas network	6.35%	GRTgaz (2019)
$\varphi_{CO_2}^{max}$	The maximal available CO_2 storage capacity for France in 2050	93MtCO_2***	BRGM (2009) & CCFN (2019)[5]

* This parameter is calculated by summing hourly power production from this hydroelectric energy resource over each month of the year to capture the meteorological variation of hydroelectricity, using the online portal of RTE[6].
** Hourly run-of-river power production data from the RTE online portal has been used to prepare the hourly capacity factor profile of this energy resource, while other VRE profiles are prepared from renewables.ninja website explained in chapter 2.2.1.
***The average of 4 scenarios presented in BRGM leads to 53MtCO_2/year of available onshore storage for France. The French Norwegian collaboration on carbon capture and storage approves 20MtCO_2/year of storage in the North Sea, and a possible extension of the collaboration for a supplementary 20MtCO_2/year.

[1] https://github.com/BehrangShirizadeh/EOLES/blob/master/inputs/lake2006.csv
[2] https://github.com/BehrangShirizadeh/EOLES/blob/master/inputs/vre_profiles2006f.csv
[3] https://github.com/BehrangShirizadeh/EOLES/blob/master/inputs/max_capas.csv
[4] https://github.com/BehrangShirizadeh/EOLES/blob/master/inputs/t_profiles.csv
[5] https://www.ccfn.no/actualites/n/news/french-norwegian-collaboration-on-carbon-capture-and-storage.html
[6] https://www.rte-france.com/fr/eco2mix/eco2mix-telechargement

Appendix 5. Acronyms of energy production, conversion and storage technologies

Table A. 6 Technology labels and their definitions

Technology label	Explanation	Technology label	Explanation
Offshore	Offshore wind power (both floating and grounded)	**G2P**	Gas-to-power options (OCGT, CCGT and CCGT-CCS)
Onshore	Onshore wind power	**G2H**	Gas-to-heat options (centralized and decentralized boilers)
PV	Solar PV (ground and utility and residential rooftop)	**G2ICE**	Gas for transport by ICEs
Hydro	Hydro-electricity (both run-of-river and lake generated)	**Resistive**	Electrical heating by resistive heaters
Nuclear	New nuclear power (EPR)	**Hpc**	Centralized electrical heat pumps
OCGT	Open-cycle gas turbine	**Hpd**	Decentralized (individual) electrical heat pumps
CCGT	Combined-cycle gas turbine	**Boilerc**	Centralized gas boilers
CCGT-CCS	Combined-cycle gas turbine with post-combustion CCS	**Boilerd**	Decentralized (individual) gas boilers
P2G	Power-to-gas options	**EV_train**	Electric trains
P2H	Power-to-heat options	**EV_light**	Electric vehicles for light individual transport
P2EV	Power for transport by EVs	**EV_bus**	Electric buses
Ngas	Natural (fossil) gas	**EV_heavy**	Electric heavy transport vehicles
Methanization	Renewable gas from anaerobic digestion	**ICE_light**	Light transport vehicles with internal combustion engines
Pyrogaseification	Renewable gas from pyro-gasification of biomass	**ICE_bus**	Buses with internal combustion engines
P2CH4	Methanaton (electrolysis of water and Sabatier reaction with green CO_2)	**ICE_heavy**	Heavy transport vehicles with internal combustion engines
P2H2	Power-to-hydrogen (electrolysis of water)		

Appendix 6. The main results for the central availability scenario

Table A.7 shows the installed capacity of each energy production, storage and vector change technology;

table A.7 installed capacities of energy production, conversion and storage technologies for different SCC scenarios in GW

SCC (€/tCO₂)	**0**	**100**	**200**	**300**	**400**	**500**
technology	**Installed capacity in GW**					
Offshore wind	0	0	0	0	0	0
Onshore wind	19.41	84.58	80.34	74.58	81.74	81.71
Solar PV	96	80.36	79.32	82.20	89.20	89.79
Run of river	7.5	7.5	7.5	7.5	7.5	7.5
Lake and reservoir	12.86	12.86	12.86	12.86	12.86	12.86
Nuclear	0	15.28	22.64	23.87	18.19	18.11
Natural gas	-	-	-	-	-	-
Methanization	0	0	17.35	17.35	17.35	17.35
Pyro-gasification	0	0	0	0	8.79	8.79
OCGT	2.75	4.58	2.09	0.69	0	0
CCGT	35.51	14.13	5.20	0.75	0	0
CCGT with CCS	0	0	5.47	11.5	17.24	17.31
Power-to-hydrogen	4.65	6.11	6.37	6.74	7.16	7.16
Power-to-methane	0	0	3.37	5.29	6.27	6.25
Heat network	18.23	34.29	46.66	43.73	45.68	45.63
Central HP	18.23	26.59	26.79	28.80	30.97	34.01
Individual HP	9.23	37.40	41.50	41.90	40.08	40
Resistive heating	6.14	21.15	17.92	13.51	14.53	14.82
Central boiler	0	0	0	0	0	0
Decentralized boiler	60.04	16.30	0	0	0	0
Battery	3.83	5.56	4.78	4.83	5.87	5.92
PHS	9.30	9.30	9.30	9.30	9.30	9.30
Gas storage	0	0	24.29	25.48	27.68	27.67
CTES	18.23	34.29	46.66	43.73	45.68	45.63
ITES	20.27	41.26	39.31	37.23	38.48	33.95

Table A.8 presents the annual energy production (conversion) by each energy production, storage and vector change technology;

table A.8 Annual energy production of each energy production, conversion and storage technology for different SCC scenarios in TWh

SCC (€/tCO₂)	**0**	**100**	**200**	**300**	**400**	**500**
technology	**Annual energy production in TWh**					
Offshore wind	0	0	0	0	0	0
Onshore wind	55.22	240.58	228.53	212.13	232.51	232.99
Solar PV	136.51	114.27	112.79	114.89	126.84	127.68
Run of river	28.48	28.48	28.48	28.48	28.48	28.48
Lake and reservoir	15.30	15.30	15.30	15.30	15.30	15.30
Nuclear	0	111.35	167.70	182.99	140.42	139.60
Natural gas	740.62	222.60	0	0	0	0
Methanization	0	0	152	152	152	152
Pyro-gasification	0	0	0	0	77	77
OCGT	1.75	2.29	1.04	0.33	0	0
CCGT	208.97	22.70	4.74	0.40	0	0
CCGT with CCS	0	0	8.26	17.66	71.63	71.75
Power-to-hydrogen	40.71	46.34	51.20	52.66	59.04	59.04
Power-to-methane	0	0	16.24	24.14	41.38	41.38

Central HP	151.06	120.16	116.75	123.55	129.42	129.26
Individual HP	79.87	285.205	328.30	326.89	311.46	311.17
Resistive heating	4.37	29.20	20.86	13.29	20.93	21.44
Central boiler	0	0	0	0	0	0
Decentralized boiler	219.30	30.59	0	0	0	0
Light EV	0	3.94	3.97	3.98	4.02	4.14
Heavy EV	0	0	0	0	0	0
Electric bus	0	0	0	0	0	0
Train (electric)	30	30	30	30	30	30
Light ICE	97.92	89.71	89.65	89.63	89.54	89.30
Heavy ICE	56.97	56.97	56.97	56.97	56.97	56.97
ICE bus	6.47	6.47	6.47	6.47	6.47	6.47
Battery	0.55	0.34	0.35	0.40	0.57	0.61
PHS	14.14	20.59	20.30	19.86	17.21	17.42
Gas storage	0	0	25.28	41.99	58.51	58.62
CTES	0.13	31.03	34.44	27.64	21.77	21.93
ITES	8.91	9.72	7.78	8.53	8.90	8.84

The main economic and emission related outputs of this study for different SCC values are presented in table A.9.

table A. 9 Main economic and emission related outputs

SCC (€/tCO_2)	**0**	**100**	**200**	**300**	**400**	**500**
Cost with SCC (b€/an)	48.19	57.29	59.55	59.15	58.06	55.97
Technical cost (b€/an)	48.19	52.19	60.04	60.69	66.43	66.45
CO_2 emission (MtCO_2/an)	169.97	51.09	-2.41	-5.16	-20.91	-20.95
CO_2 captured (MtCO_2/an)	0	0	2.41	5.16	20.91	20.95
Electricity LCOE (€/MWh_e)	45.04	48.77	49.23	48.92	48.14	48.14
Gas LCOE (€/MWh_{th})	25.36	49.17	59.31	60.60	66.85	68.86
Heat LCOE (€/MWh_{th})	14.22	28.74	30.63	30.71	30.90	30.87

Appendix 7. The CO_2 emissions for no social cost of carbon and the emissions from the actual French energy system

In section 3.3 we showed the CO_2 emissions for different SCC values. In the absence of a SCC, the CO_2 emissions of the energy sector are relatively low in comparison with current emissions of the energy sector (170MtCO_2/year vs. 450MtCO_2/year). This low emission in the absence of a SCC value can be explained considering several factors: First, the existing energy system in France does not rely on an optimal allocation of installed capacities of energy production technologies. This study is a greenfield optimization, which does not consider the existing energy system, but it allocates an absolute optimal case regarding the taken hypothesis for a given year. While most of the existing power plants will be decommissioned by 2050, the hydro-electric power plants will remain, that's why we fixed a minimum installed capacity of these power plants to the existing capacities. On the other hand, in case of retrofitting the nuclear power plants, the last historic nuclear power plant in France will be decommissioned by 2052 (Perrier, 2018). On the other hand, the Flamanville 3 nuclear reactor which is not commissioned yet will also be in the energy supply that is not considered in this optimization. Moreover, the lifetime of buildings, factories and the infrastructures are not taken into account. Therefore, a greenfield optimization does not reflect the existing energy system precisely. The existing energy system is highly dependent on fossil fuels especially in industry and transport sectors.

Second, the demand projections for 2050 for France are based on several energy consumption reduction assumptions in residential, tertiary and transport sectors. The final energy demand for residential and tertiary sectors for year 2015 were 490TWh and 295TWh respectively, while in the future final energy demand projections, these values are considered to be 293TWh and 168TWh respectively (SNBC, 2019). The high reduction in the final energy demand for each sector is thanks to increased efficiency of electronic appliances, increased isolation of buildings and replacement of light bulbs with LEDs. The final energy demand for the transport sector was 509TWh for 2015 (SNBC, 2019), and it is projected to be less than 200TWh in 2050. ADEME projects a final energy demand reduction from 149Mtoe to 82Mtoe from 2010 to 2050 (ADEME, 2017). Moreover, all the existing scenarios for future French energy mix (négaWatt, 2017, ADEME, 2017 and SNBC, 2019) project a much lower energy loss from the primary energy production to final energy consumption. According to SNBC (2019), a primary energy consumption of 250Mtoe for France for the year 2015 satisfies the 142Mtoe of final energy demand at this year. Therefore, although a higher final energy demand is not studied in this paper, one can easily predict the impact of increasing the energy demand for low SCC values; the emissions will be much higher because of increased usage of cheap natural gas, and since the renewable gas production is limited by land-use and technical constraints, a carbon neutral energy system may need a higher social cost of carbon than only €200/tCO_2.

Appendix 8. Energy mix for different availability scenarios

Figure A.1 shows the primary energy mix of each end-use for different availability and the final energy consumption. In case of unavailability of nuclear power, the energy mix becomes fully renewable from the SCC value of €300/tCO_2 on, with no change in emission or cost of the energy system. On the other hand, without VRE technologies, the primary energy contains 71% of nuclear energy from a SCC of €100/tCO_2 on. While in all the availability scenarios, the natural gas is phased out for €200/tCO_2 or €300/tCO_2 of SCC, in case of absence of renewable gas, natural gas remains an important part of primary energy even for the SCC of €500/tCO_2.

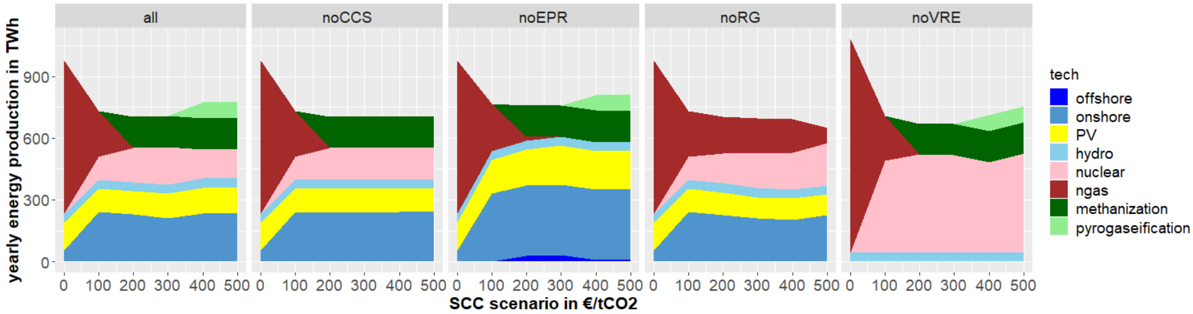

Figure A. 1 Primary energy mix for each technology availability scenario for different SCC values

Figures A.2 and A.3 show the electricity and the gas mix for each availability scenario and SCC value. In the absence of nuclear power, offshore wind power appears in the energy mix for SCC of €200/tCO_2. By increasing the SCC value from €200/tCO_2 on, this technology is phased out thanks to the increased usage of renewable gas and the flexibility gains from it. For all the availability scenarios in the presence of VRE technologies, the share of nuclear power in energy mix never exceeds 25% and the remaining is provided by renewable energy sources.

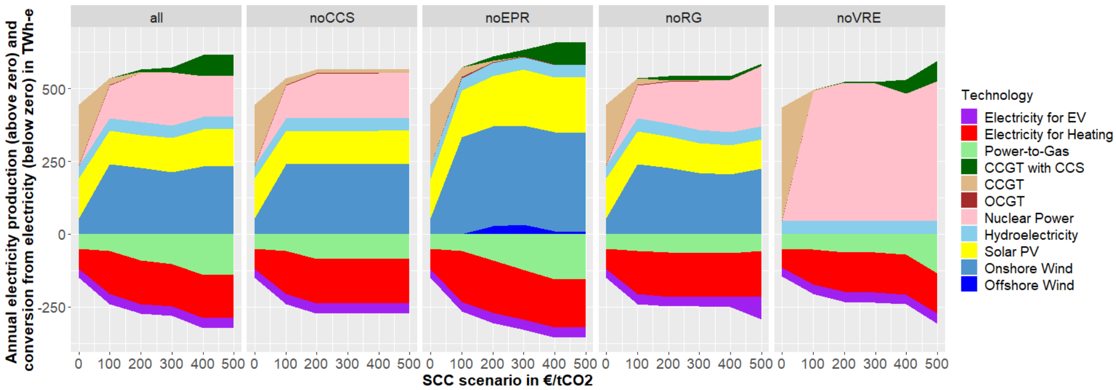

Figure A. 2 Electricity production mix for different technology availability scenarios

For all the scenarios, the main function of gas is the fuel for the transport sector, and electricity production for zero SCC, where cheap natural gas is used to produce electricity. From the SCC of €200/tCO_2 on, the gas production is dominated by renewable gas technologies, and synthetic gas from power-to-gas. For the scenario where no renewable gas is available, the gas supply is dominated by fossil gas, even for the highest SCC values, as we observed in figure A.1 as well.

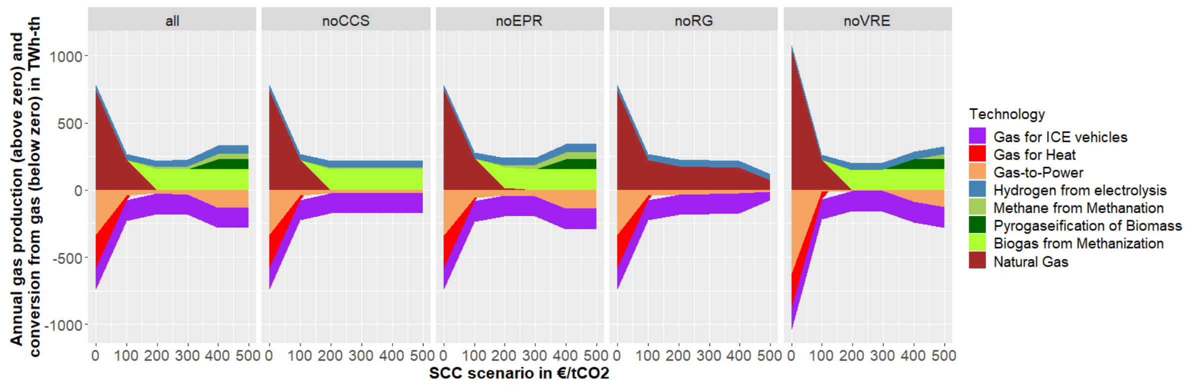

Figure A. 3 Gas production mix for different technology availability scenarios

Figure A.4 shows the technologies meeting the sectorial demands of heat and transport end-uses. The heat supply technologies remain the same for each availability scenario, following the same pattern as the central scenario: nearly half of the heat is provided from decentralized boilers for zero SCC value, and from the SCC of €100/tCO_2 the share of gas-to-heat drops to less than 10% and from €200/tCO_2 of SCC on, the heat network is fully electrified, mainly by heat pumps (especially individual heat pumps). Resistive heating has a direct relation with the share of VRE technologies. The efficiency of resistive heating is much lower than heat pumps, but so is its cost. Therefore, for cheap electricity hours where the electricity supply exceeds the demand, storage and power-to-X[1] technologies, resistive heating is considered as a useful option to either provide heating or to charge the heat storage tanks. Since the increased share of VRE leads to increased share of zero price hours in the power system (Shirizadeh et al, 2019), there is a positive correlation between the share of VRE technologies in power production and the share of resistive heating in heat production.

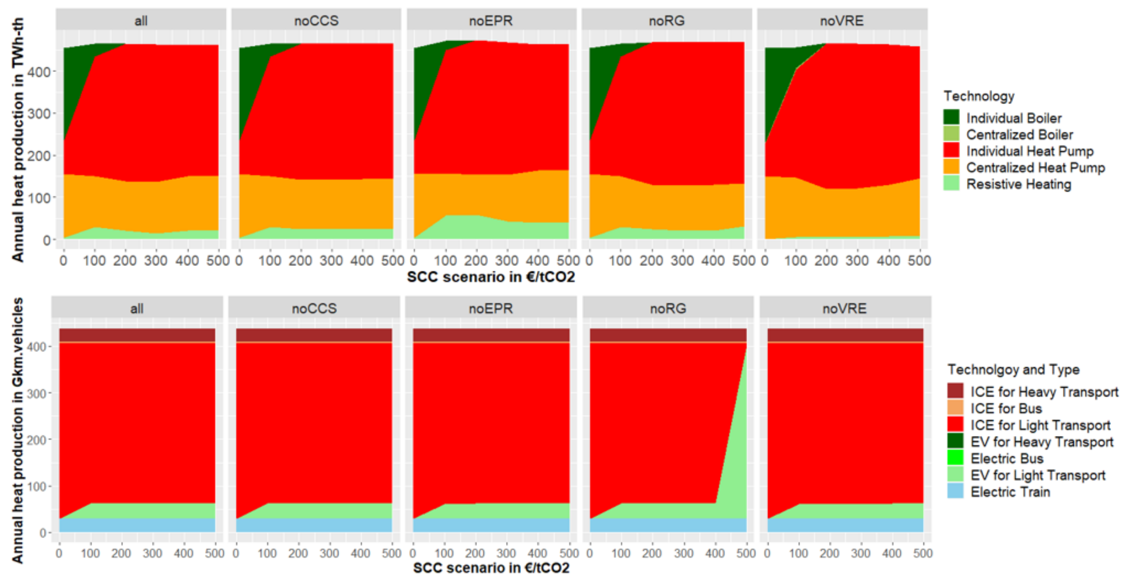

Figure A. 4 Heat and transport demand and the supply technologies for all the availability scenarios and different SCC values

The transport supply technologies' shares for different availability scenarios follow the same pattern as the scenario with the central availability scenario as well. As discussed previously, the transport sector is dominated but ICE vehicles powered by either natural gas for zero SCC or renewable gas for

[1] X stands for gas, heat or transport: power-to-gas, power-to-heat and power-to-transport.

higher SCC values. In case of unavailability of renewable gas, the high cost of fossil gas with the emission tax for very high SCC value of €500/tCO_2 results in replacement of ICE vehicles in light transport by electric vehicles. Therefore, availability of renewable gas is also a key enabler of ICE vehicles' dominance in the transport sector.

Appendix 9. A Back-of-envelope calculation to compare EV and ICE vehicles

Let's consider 500Gvehicle.km of transport demand. The fuel efficiencies for electric and ICE vehicles are 8km/kWh$_e$ and 3.85km/kWh$_{th}$ respectively. Therefore, to satisfy this light transport demand, 130.21TWh$_{th}$ of gas or 62.5TWh$_e$ of electricity will be necessary. The price projected for natural gas for natural gas is €23.5/MWh$_{th}$, and the average electricity price is around €48/MWh$_e$. Thus, in case of no carbon tax the variable cost for electric vehicles will be €3b/year while for ICE vehicles it will be €3.06b/year and for a SCC of €500/tCO_2 this variable cost goes up to €18b (I).

Now let's consider the needed investment for charging and storage infrastructures; we consider each electric vehicle user to also have a charging point worth of average 5kW of charging power. For a fleet of 30M EVs, the charging capacity will be 150GW. Considering an autonomy of 300km per EV a battery energy capacity of 37.5kWh for each EV and an overall energy capacity of 1.125TWh will be needed for the fleet of 30M EVs. Therefore, using the economic parameters in table S.8, an annual investment cost of €15.88b/year will be needed for this EV fleet. Each gas charging station can charge 400 vehicles per day, considering charging frequency of once each week for each ICE vehicle, 2800 ICE vehicles can be charged by each ICE charging station (costing €300,000 for 15 years of lifetime, therefore an annuity of €28,563/year) each week, therefore 10,714 charging stations will be needed, which would cost €306M/year (II).

From (I) and (II) we can calculate a breakeven point for different SCC values, where it would be more preferable for a light vehicle user to choose an electric vehicle instead of an ICE vehicle. Knowing that each GWh of natural gas contains 22.95tCO_2, the breakeven SCC can be calculated from the equality below:

$$15.88+3 = 0.306 + 3.06 + SCC\times22.95\times130.21/100000$$

This break-even point is €519/tCO_2 and for this SCC value, natural gas is already abandoned from the results.

Considering the renewable gas as fuel for ICE vehicles, using the same numbers and reasoning above, we can study the relative economic attractiveness of ICE vehicles fuelled with renewable gas and electric vehicles.

According to figure 4, the gas price is roughly €25/MWh$_{th}$ (nearly the price of natural gas) for a zero SCC and this price goes up to €68/MWh$_{th}$ for the SCC of €500/tCO_2 because of mobilization of two more expensive gas options (biogas and pyro-gasification of biomass). For the highest SCC value, the cost of a fully EV fleet being equal to €18.88b/year is higher than the cost of the ICE fleet (€8.85b/year) when only battery and charging points and used energy cost are considered. For lower SCC values, the price of gas would be even less, and the ICE vehicle fleet would cost even cheaper.

It can be concluded that ICE vehicles are more interesting from the cost-optimality point of view. The small share of EV in the final transport mix for the light transport is thanks to the zero price hours of electricity (high VRE generation hours where the electricity price is the marginal cost of VRE technologies, in other words; zero.) and limited renewable gas availability.

Appendix 10. Sensitivity to heat network coverage limit

In our central scenario, we considered that 52.2% of final heat demand can be satisfied by the heat network (because of urbanization and density limitations of France – Appendix 3.1). In case of higher urban population density and higher urbanization assumptions, the value can go up and vice versa. Therefore, to account for a high range of heat network coverage possibilities, we applied a variation of +/-50% in the 52.2% of final heat demand that can be satisfied by heat network (low scenario of 26.1% of heat demand and high scenario of 78.3%).

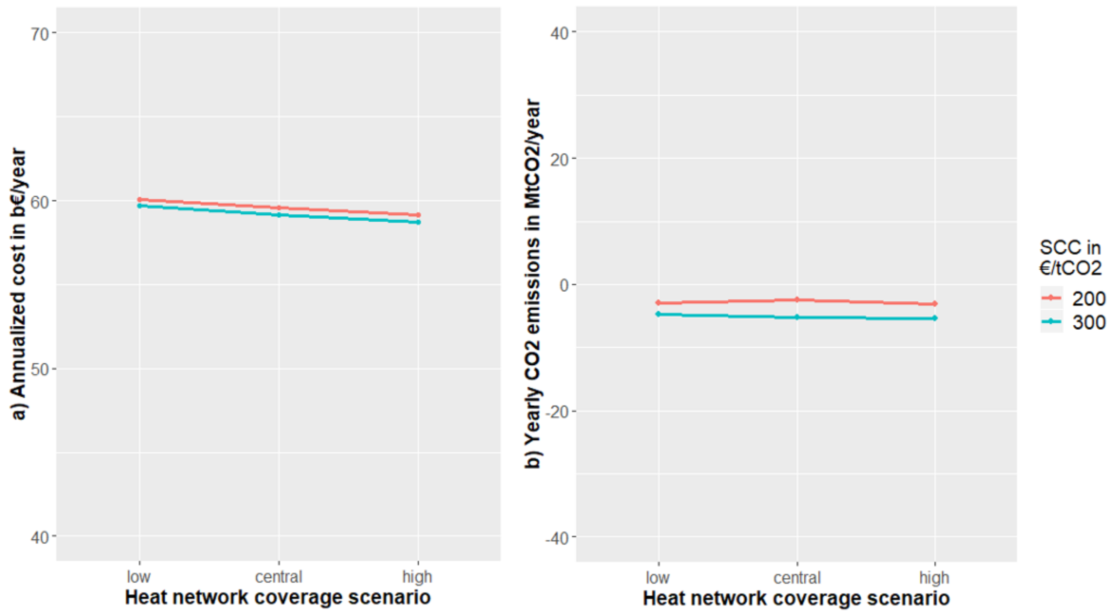

Figure A. 5 Sensitivity of the yearly total cost and emissions of the energy system to the +/-50% variation of the maximal heat network coverage limits

Figure A.5 summarizes the cost and emission related results of the sensitivity analysis over the heat network coverage for SCC scenarios of €200/tCO_2 and €300/tCO_2.

Heat network coverage limit does not impact the system cost and the yearly emissions for any of the SCC values. The cost variation stays below 2% for a threefold change in the heat network coverage limit, and the emissions stay nearly stable and below zero in any SCC scenario.

Appendix 11. Sankey flow diagram for the proposed SCC of 300€/tCO_2

Figure A.7 shows the Sankey flow diagram for the proposed SCC scenario of 300€/tCO_2. This figure summarizes the whole energy system, technologies and the interactions between different vectors and end-use demands for the proposed robust SCC value.

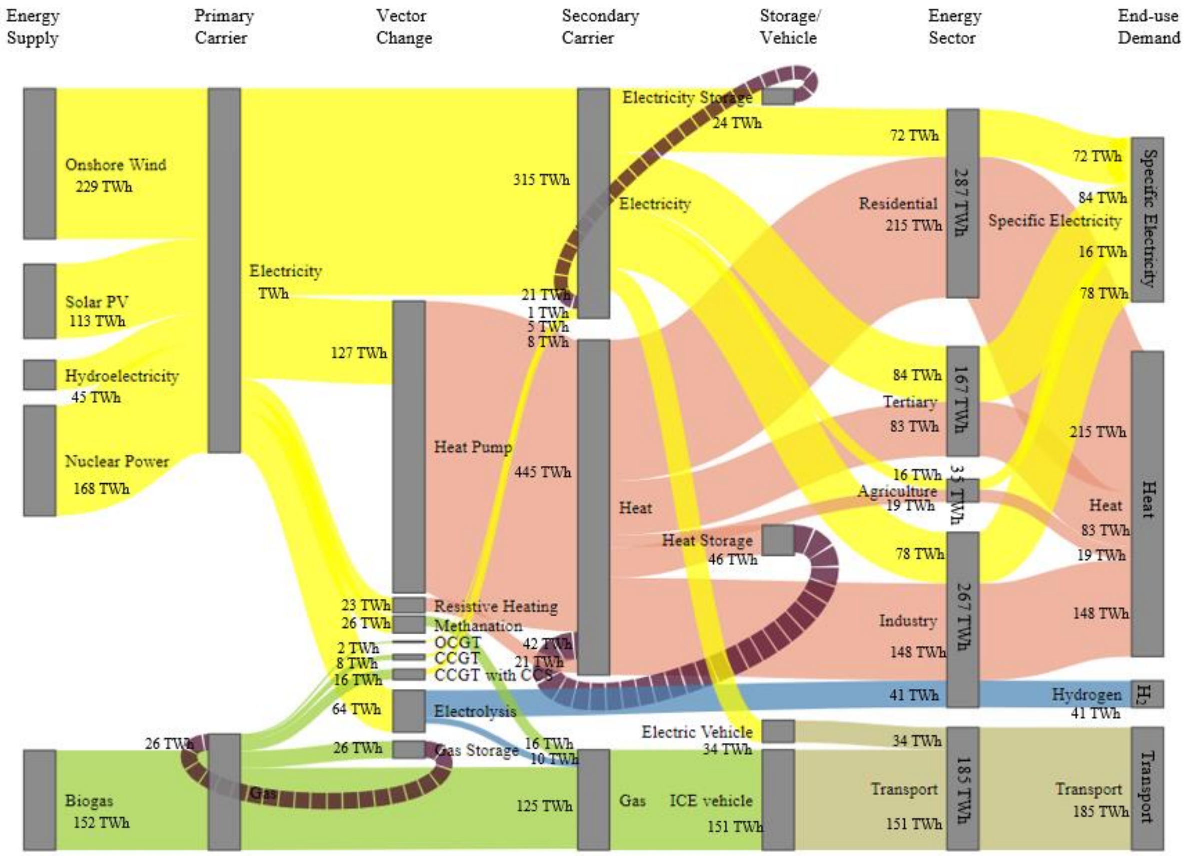

Figure A. 6 Sankey flow diagram for the energy system for the proposed SCC of 300€/tCO2 ; yellow color represents the electricity flow, pink represent heat flow, green represents gas flow, blue represents hydrogen flow and khaki represents transport sector. The purple flows in each of electricity, heat and gas sectors are the energy storage in each of the carriers.

Appendix 12. Sankey flow diagram in the absence of nuclear energy

Figure A.7 shows the Sankey flow diagram for the case with no nuclear power. As we can see, offshore wind power appears in the optimization results, and power productions from onshore wind and solar PV are much more than the case with nuclear power. Overall electricity production is increased by 54TWhe serving the same electricity, transport and heat demand. Higher energy storage leads to higher storage related loss from electricity (7TWhe vs. 3TWhe) and increased share of VRE technologies leads to an increased curtailed electricity (25TWhe vs. 19TWhe). However, as we discussed previously, the availability of nuclear power has negligible impact on the energy system cost and total CO2 emissions of the system.

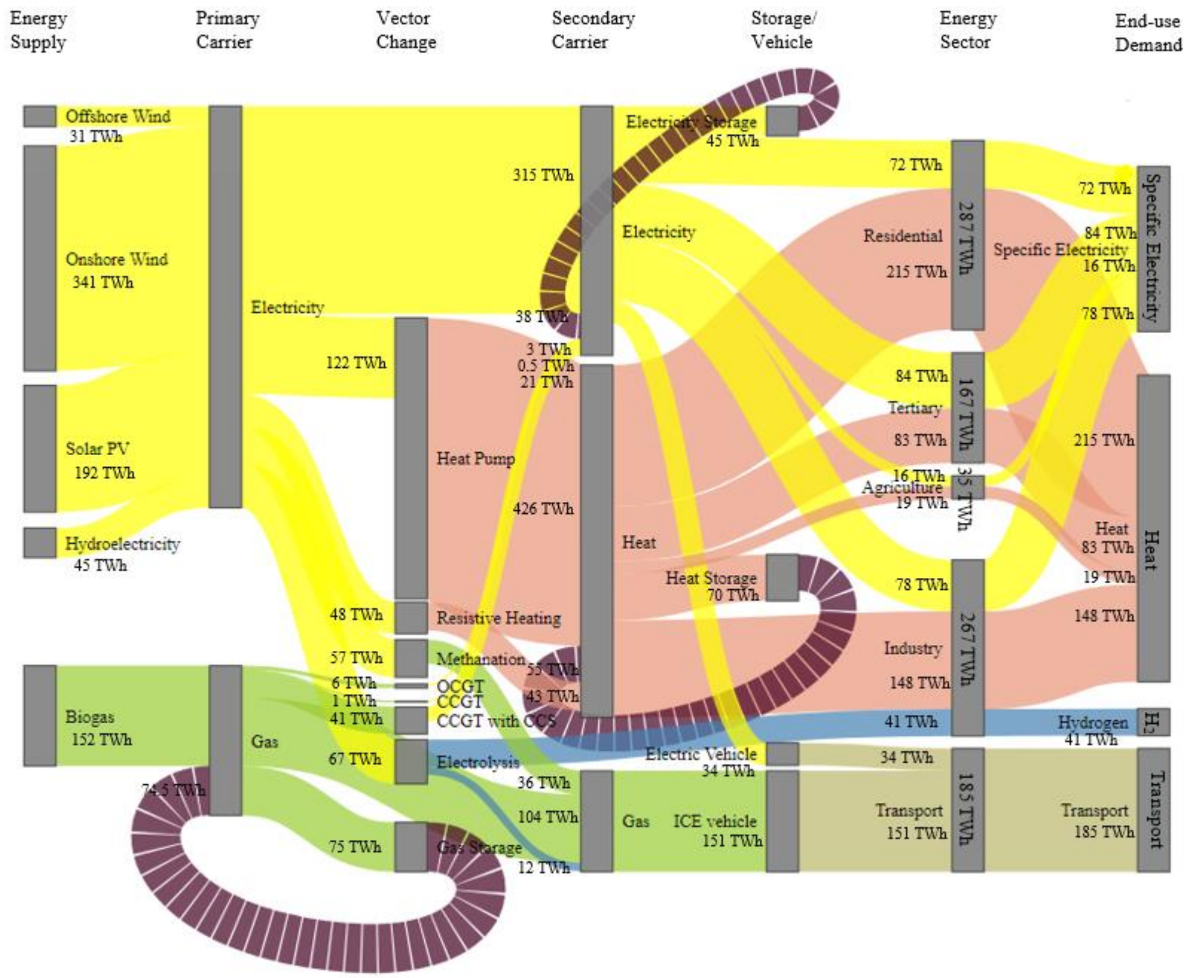

Figure A. 7 Sankey flow diagram for the energy system for the proposed SCC of 300€/tCO2 for the case without nuclear energy; yellow color represents the electricity flow, pink represent heat flow, green represents gas flow, blue represents hydrogen flow and khaki represents transport sector.