Low-carbon technologies for the French power sector; what role for renewables, Nuclear & CCS?

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Chaire Modélisation prospective au service du développement durable

Introduction

- Article 4 of Paris agreement (COP 21):
  - GHG emission neutrality by second half of 21st century
- PPE (2019): “36% of electricity from renewables by 2028” (40% by 2030), and 50% of electricity from nuclear by 2035
- Literature for France
  - **Petitet et al. (2016)**, **Krakowski et al (2016), Villavicencio et al (2018)**: “Optimal mix consists of mostly nuclear power and/or CCS, but not an important place for the renewables”.
  - **ADEME (2015, 2018)**: “The main contributor to the energy transition will be renewables, but not Nuclear power or CCS”
- Waisman et al. (2019): "By 2050, drastic increases of renewables to 70 to 85% of electricity production and decreases of unabated fossil sources to near-zero in the case of coal are necessary in the power generation sector.“
- IPCC (2018): “Significant near-term emissions reductions and measures to lower energy and land demand is necessary to limit the carbon-dioxide removal (CDR) technologies to a few hundred $GtCO_2$ without reliance on BECCS”
- Motivation
  - Which cost hypotheses (especially for EPR and VREs), and carbon tax/remuneration values are compatible with these different visions of the future?

Questions addressed

- The optimal installed capacities of power production and storage technologies
- How much does it cost?
- The carbon taxation policy impact?
- Negative emission technologies?

Outlines

- Model description
- Input data & assumptions
- Results
- Conclusions

Model description (1/2)

- Optimal planning and operation of power system
  => simultaneous optimization of dispatch and investment

$$\min_{Q_i, E_{i,t}} C(Q_i, E_{i,t})$$
$$\text{s.t.} \sum_i E_{i,t} \geq d_t \;,$$
$$Q_i \geq E_{i,t}, \ldots$$

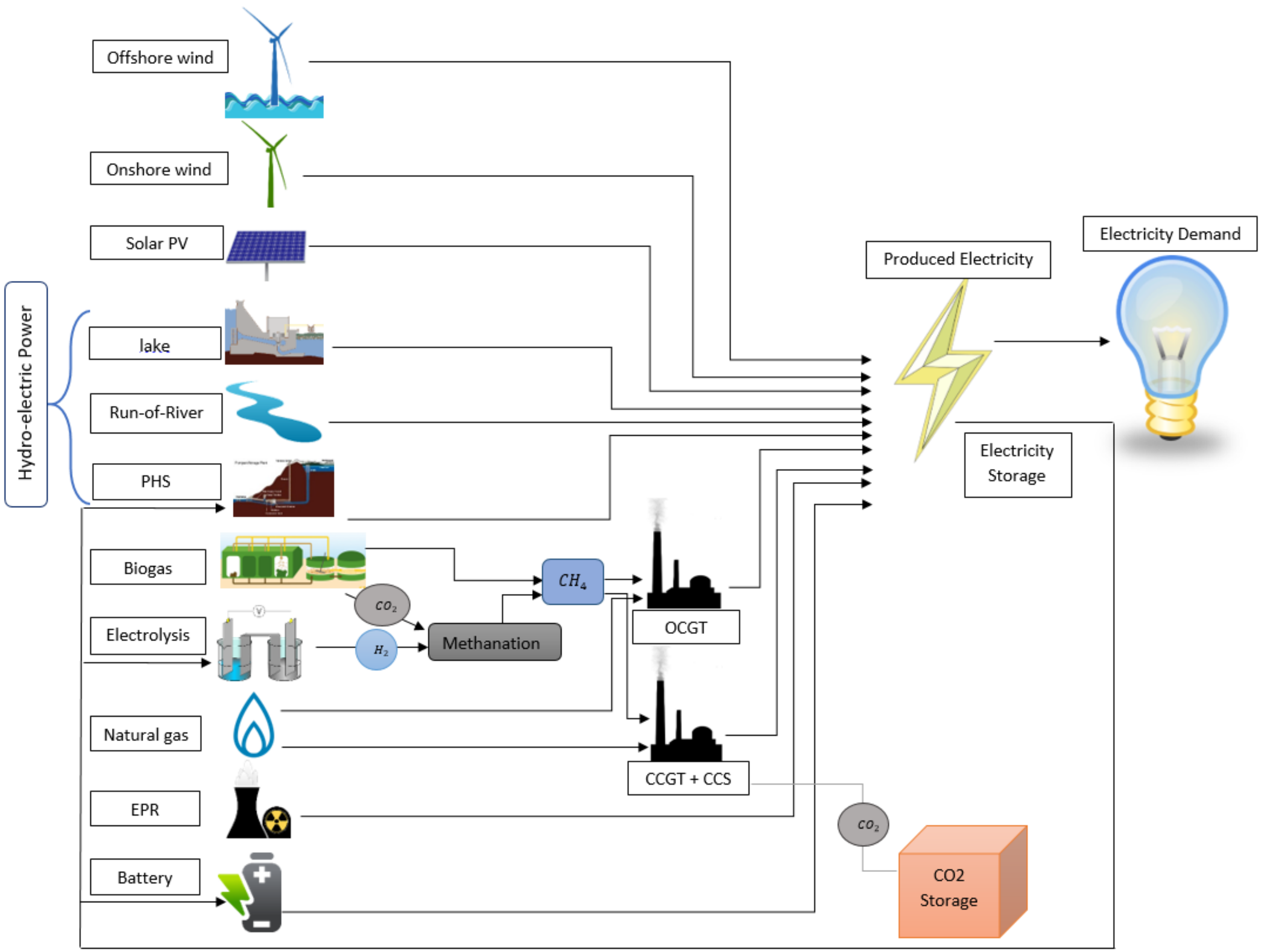
Q_i= installed capacity of technology i
$E_{i,t}$= power production of technology i at hour t
d_t=demand for electricity at hour t

- Assumptions:
  Perfect competition with full information, rigid demand, wholesale power market, single buyer model (one node), linear constraints and cost function of the form:

$$C(Q_i, E_{i,t}) = \sum_i fc_i Q_i + \sum_i \sum_t vc_i E_{i,t} + \sum_i \sum_t tax_{CO_2} e_i E_{i,t}$$

fc_i= fixed costs of technology i
vc_i= variable costs of technology i
tax_{CO_2} = carbon tax
e_i = specific emissions of technology i

Model description (2/2)



Input data & assumptions

- Continental France
- Weather year: 2006 (Shirizadeh et al. 2019)
- Electricity consumption
  - ADEME's central demand scenario for 2050
- Offshore and onshore wind and solar PV hourly profiles:
  - Renewables.ninja (from downscaling of NASA's « MERRA-2 data reanalysis »)
  - Great correlation with RTE's data – wind 98% and PV 97% (Moraes et al 2018)
  - Offshore wind power: sites in project
  - Onshore wind and solar PV: 1 site in each *department*, proportional to installed capacity
- Hydro power resources : RTE 2016
- Nuclear power: NEA (2018)
- Natural gas price: WEO 2018 (IEA)
- CO2 transport and storage costs: Rubin et al. (2015)
- Capacity constraints (Offshore and onshore wind, PV, biogas and hydro-electricity)
  - ADEME *Trajectoires d'évolution du mix électrique à horizon 2020-2060* (2018)
  - ADEME *visions 2030-2050* (2013)
- Costs and losses
  - JRC *Cost development of low carbon energy technologies* (2017)
  - JRC *Energy Technology reference indicator projections for 2010-2050* (2014)
  - *Fuel cell and hydrogen joint undertaking* (2015)
  - Schmidt et al *Projecting the Future Levelized Cost of Electricity Storage Technologies* (2019)
  - Discount rate => Quinet, E. (2014). *L'évaluation socioéconomique des investissements publics*
  - SCC => Quinet, A. (2019*). La valeur de l'action pour le climat. France Stratégie*

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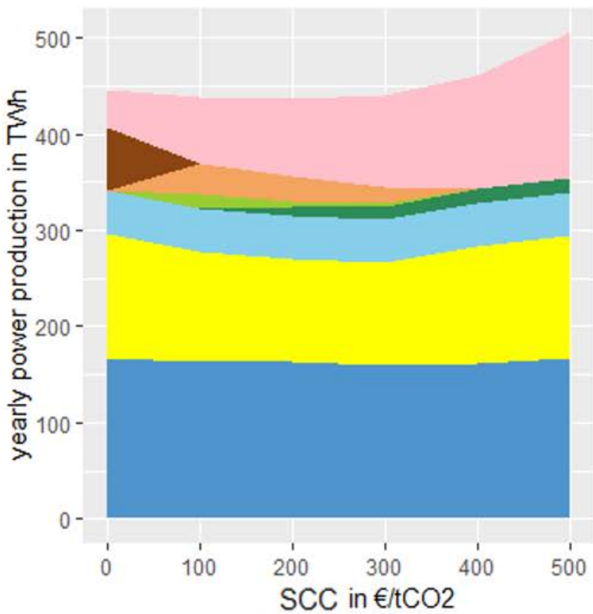
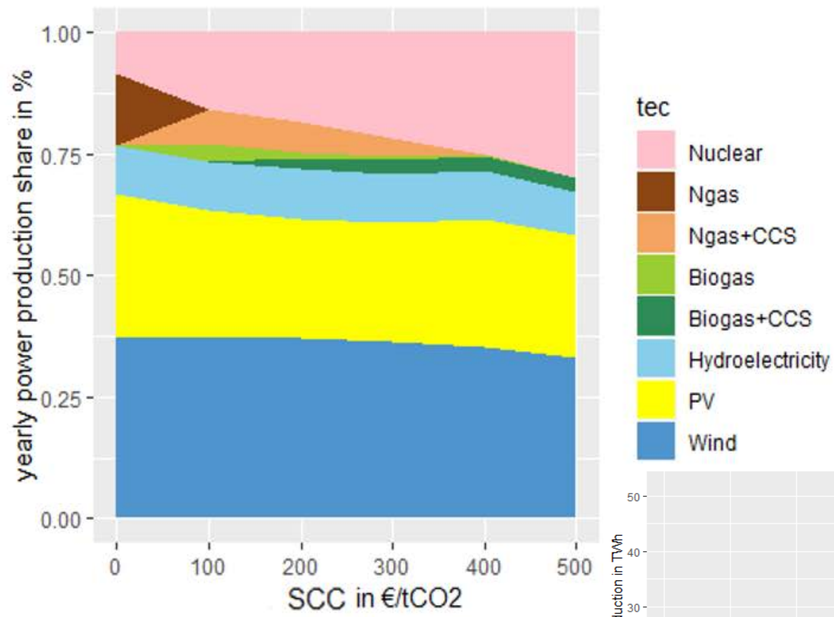
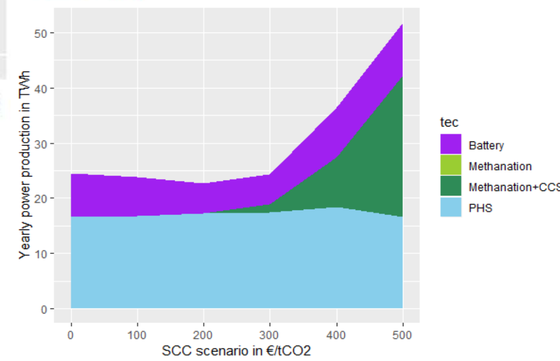
RESULTS

Central cost scenario (1/2)

Power mix



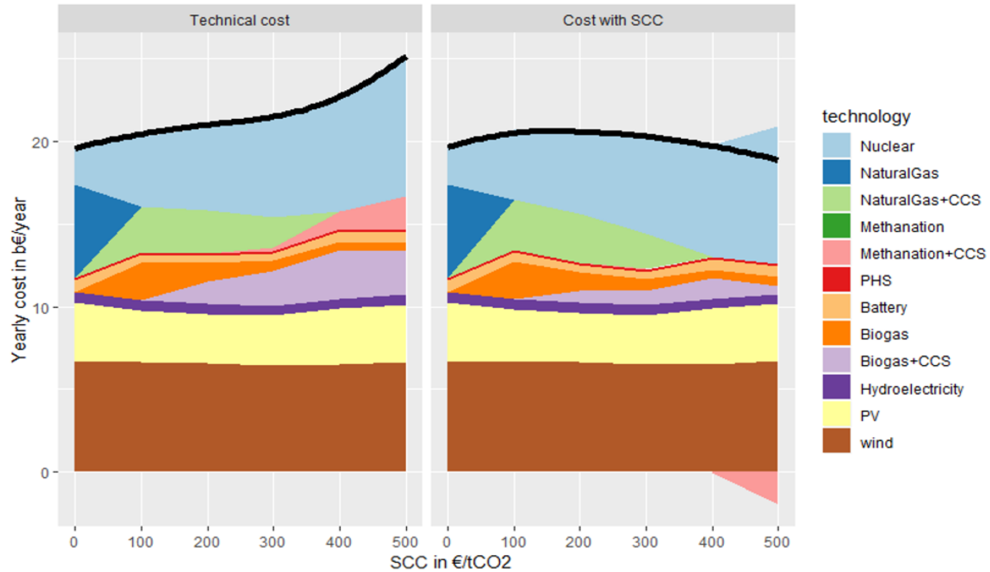


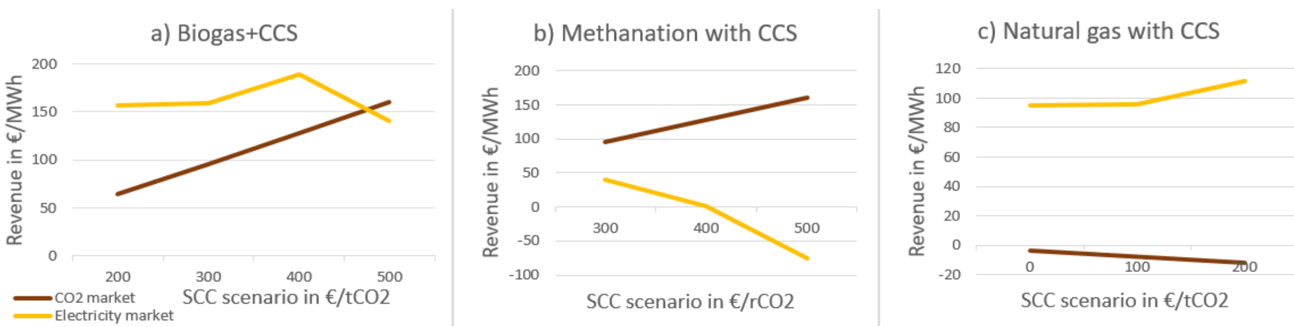


- Optimal power mix => ~75% RES, ~25% other.
- CO_2 tax:
  100€/tCO_2+ => natural gas with no CCS is replaced by natural gas with CCS and bio-energies.
  400€/tCO_2+ => natural gas with CCS is replaced by power-to-gas (methanation) with CCS

Central cost scenario (2/2)

Costs & revenues

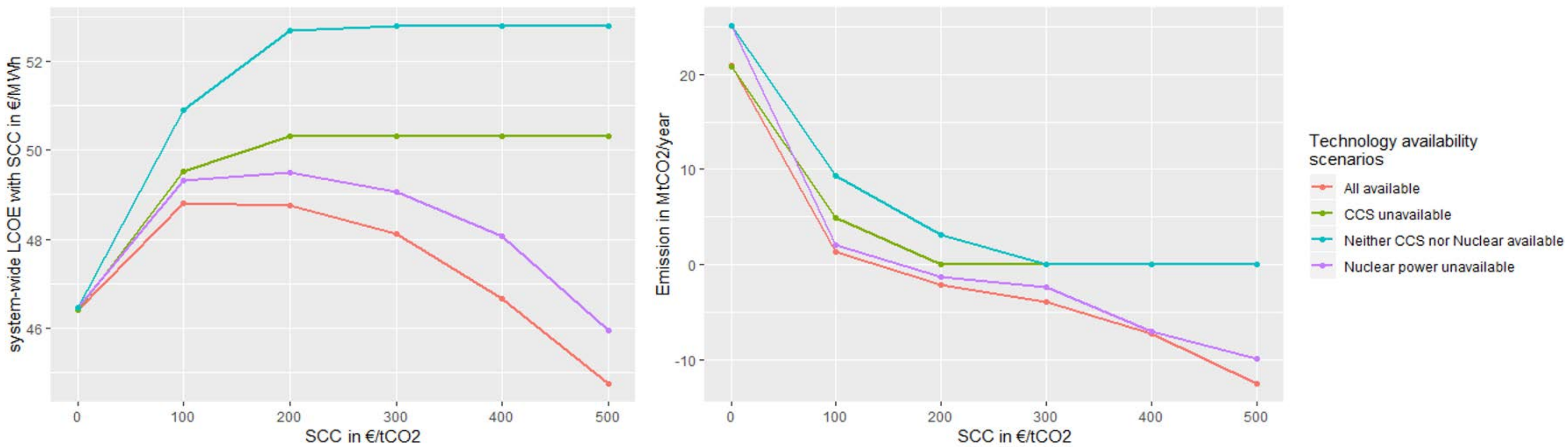




- **for 200€/tCO$_2$ of SCC and more, two costs diverge significantly.**
- **Maximal gap 6b€/year (~20% of the technical cost).**
- **By increase of CO$_2$ tax, the CO$_2$ market gains higher importance than power market.**

Availability of CCS and EPR

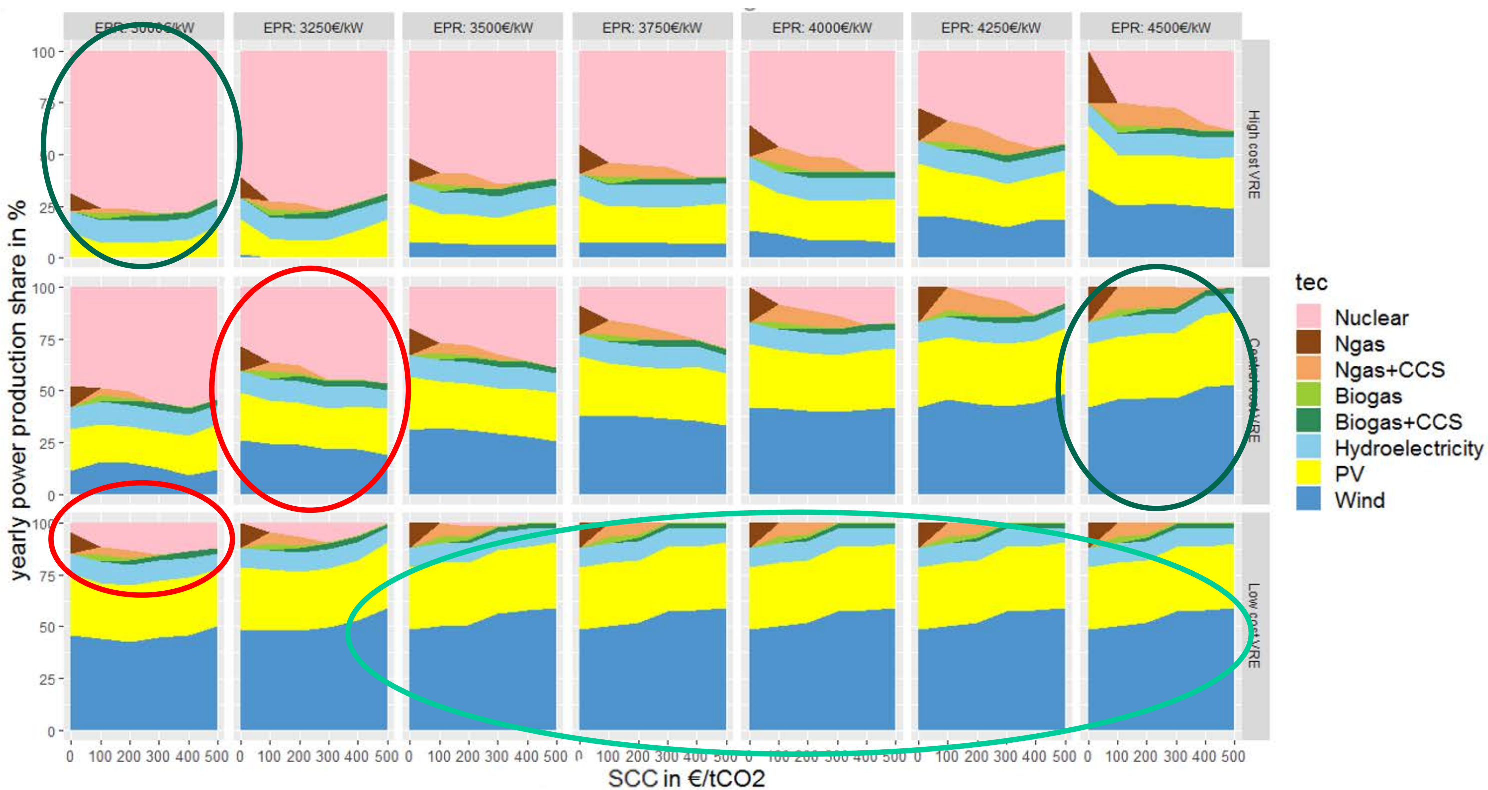
Cost and emissions



- **Availability of nuclear power leads to an average cost reduction of 2.5€/$\mathrm{MWh_e}$ for SCC scenarios of 200€/tCO_2 and more.**
- **Availability of CCS leads to an average cost reduction of 1.5€/$\mathrm{MWh_e}$ for SCC of 100€/tCO_2 and up to 7€/$\mathrm{MWh_e}$ for SCC of 500€/tCO_2.**
- **System with neither nuclear power nor CCS reaches zero CO_2 emissions with a carbon tax of 300€/tCO_2.**
- **System without CCS reaches carbon neutrality for a tax of 200€/tCO_2, and system without Nuclear only reaches nearly zero CO_2 emissions with 100€/tCO_2.**

Different cost scenarios (1/2)

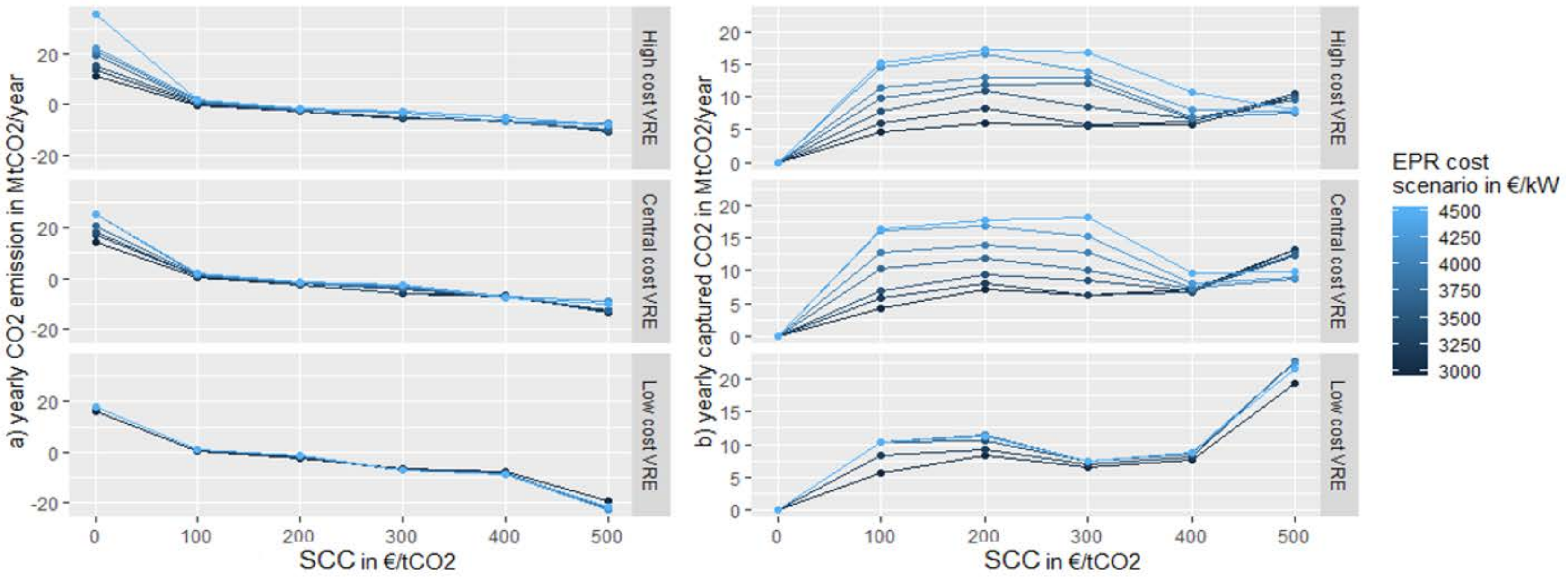
Power mix



- **The ratio between power production by renewable technologies and nuclear power is highly sensitive to the chosen cost scenario:**
  a) Nuclear power can provide 0% to 75% of final power production.
  b) RES share almost never drops below 25%, while it can reach 100%.

Emissions and needed CO2 storage

Yearly emitted and captured carbon-dioxide



- ➢ **Whatever the VRE and Nuclear power cost scenario, nearly always carbon neutrality is reached with a carbon tax of 100€/t CO_2.**
- ➢ **Negative emissions can go up to -22MtCO_2/year.**
- ➢ **While for high and central VRE cost scenarios, the needed CO_2 storage does not exceed 18MtCO_2/year, low VRE cost scenario leads to more than 20MtCO_2/year storage capacity for 500€/tCO_2 of SCC.**

Conclusion

- #1. for central nuclear and VRE power cost scenarios, optimal power mix consists of ~75% renewable power, and the remaining ~25% is shared among the other technologies.
- #2. For a carbon tax of 100€/tCO_2 and more, natural gas with no CCS is abandoned and replaced by natural gas with CCS and bio-energies.
- #3. for high CO_2 taxes (from 300€/tCO_2 on), natural gas with CCS is also eliminated and replaced by power-to-gas (methanation).
- #4. For a carbon tax of 200€/tCO_2 or more, emissions become negative.
- #5. Even for high carbon taxes, no more than 18MtCO_2/year of CO_2 storage capacity is needed (less than half of the CO_2 captured and stored worldwide).
- #6. Combustion power plants coupled with CCS (including BECCS) can decrease the cost of carbon neutral or negative emission power system by up to 18%, leading to an important carbon market size.

Merci!

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Annex 1 – Production side Costs

Technology	Overnight costs (€/kW$_e$)	Lifetime (years)	Annuity (€/kW$_e$/year)	Fixed O&M (€/kW$_e$/year)	Variable O&M (€/MWh$_e$)	Construction time (years)	Discount rate (%)	Efficiency (%)	Source
Offshore wind farm*	2330	30	150.8643	47.0318	0	1	4.5	-	JRC (2017)
Onshore wind farm*	1130	25	81.1569	34.5477	0	1	4.5	-	JRC (2017)
Solar PV*	423	25	30.6803	9.2262	0	0.5	4.5	-	JRC (2017)
Hydroelectricity – lake and reservoir	2275	60	115.1939	11.375	0	1	4.5	-	JRC (2017)
Hydroelectricity – run-of-river	2970	60	150.3851	14.85	0	1	4.5	-	JRC (2017)
Biogas (Anaerobic digestion)	2510	25	141.6044	83.9	3.1	1	4.5	-	JRC (2017)
Natural gas	-	-	-	-	50/61**	-	-	-	IEA (2018)
Nuclear power	3750	60	262.5869	97.5	9.5***	10	4.5	38%	JRC (2014)
CCGT with CCS	1280	30	82.1173	32	18****	1	4.5	55%	JRC (2017)
OCGT	550	30	35.2848	16.5	-	1	4.5	45%	JRC (2014)

*For offshore wind power on monopiles at 30km to 60km from the shore, for onshore wind power, turbines with medium specific capacity (0.3kW/m^2) and medium hub height (100m) and for solar power, an average of the costs of utility scale, commercial scale and residential scale systems without tracking are taken into account. In this cost allocation, we consider solar power as a simple average of ground-mounted, rooftop residential and rooftop commercial technologies. For lake and reservoir hydro we take the mean value of low-cost and high-cost power plants.

**50€/MWh-e for CCGT power plants with 55% efficiency, and 61€/MWh for OCGT power plants with 45% efficiency (accounting for 9$/MBtu, projected for Europe for the year 2040 by IEA in the World Energy Outlook 2018) .

***This variable cost accounts for 2.5€/MWh-e of fuel cost and 7€/MWh of other variable costs, excluding the waste management and insurance costs.

****this variable cost accounts for a 500km CO_2 transport pipeline and offshore storage costs estimated by Rubin et al. (2015).

Annex 2 – Storage side Costs

Technology	Overnight costs (€/kW$_e$)	CAPEX (€/kWh$_e$)	Lifetime (years)	Annuity (€/kW$_e$/year)	Fixed O&M (€/kW$_e$/year)	Variable O&M (€/MWh$_e$)	Storage annuity (€/kWh$_e$/year)	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)
Methanation	1150	0	20/25*	87.9481	59.25	5.44	0	1	59%/45%	ENEA (2016)

Annex 3 – Nuclear power

- Interest During Construction (GEN IV international forum, 2007):

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

- Ramping rate (OECD – NEA, 2011)

100-80-100 => 100,000 cycles
100-60-100 => 15,000 cycles
100-40-100 => 12,000 cycles

- Construction time:

Hinkley Point C => 17+ years
OL 3 (Olkiluoto) => 15+ years
Flamanville => 15+ years

- Elements considered in cost

Civil and structural costs, Major equipment cost, balance of plant cost, Electrical and I&C supply and installation, Project indirect costs, development costs, interconnection costs, fuel cost, maintenance and labour related costs (interest during construction and decomissioning cost)

- Elements not considered in costs

Insurance cost, waste management.

- Maximal capacity factor (maximal yearly average) = 90%

Annex 4 – Grid related and single-node assumption limitations

- (CRE, 2019)

1/3 of electricity bill (60-70€/MWh) is production cost

- RTE (2018), Watt scenario for 2035:

71% RES, 1bn/year of grid reinforcement cost

- EirGrid (Irish TSO):

90% RES, 1€/MWh of integration cost for VREs

- Connection to the grid included in model
- Internal congestion:

Not considered in the model, beyond our scope, but we can assume propostional installation of storage in line with spatial demand inadequacies

- Best location for wind power and solar PV

95 departments, aggregation proportional to existing capacity

For Wind: 8.9% of overall installed capacity in the best location

For solar PV: 9.2% of the overall installed capacity in the best location

Annex 5 – Cost decreasing and increasing factors

- Increasing the cost

1 - Transmission and distribution network

2 - Perfect weather forecast => Growrisankaran et al (2016):
“intermittency overall is quantitatively much more important than unforecastable intermittency.”
3 - Social acceptability => the installed capacities are well below ADEME ’s (2018), WindEurope’s, CEREMA ’s (2017) and Enevoldsen et al’s (2019).

4 - Discount rate => 4.5% < 7% (private) , penalizing future geneartions

5 - Optimistic nuclear power and construction time hypothesis

- Decreasing the cost

1 - DSM => ADEME (2015)

2 - Interconnections with neighbouring countries => Annan-Phan and Roques (2018) lower price volatility

3 - Spatial optimization

4 - low LR for VREs

Annex 6 – Renewables.ninja

Wind Power

98% correlation with TSO data

Raw data selection
- MERRA-2 wind speed values with 60km × 70km grid spatial resolution taken published by NASA in [1]

Wind speeds downscaling to wind farms
- Interpolation of speeds to the specific geographic coordinates of each wind farm using LOESS regression

Calculation of hub height wind speed
- Extrapolation of wind speeds to the hub height of the turbines at each site with logarithm profile law (2, 10 and 50m)

Power conversion
- Power curves are built as primary data from [2], smoothed to represent a farm of several geographically dispersed turbines, using Gaussian filter

Bias correction at continental and country level

Solar Power

97% correlation with TSO data

Raw data calculation and treatments
- MERRA 50km × 50km resolution, the diffuse irradiance fraction estimated with Bayesian statistical analysis from [3], the global irradiation calculated in inclined plane, temperature at 2m taken by MERRA

Downscaling of solar radiation to farm level
- Values are linearly interpolated from grid cells to the given coordinates

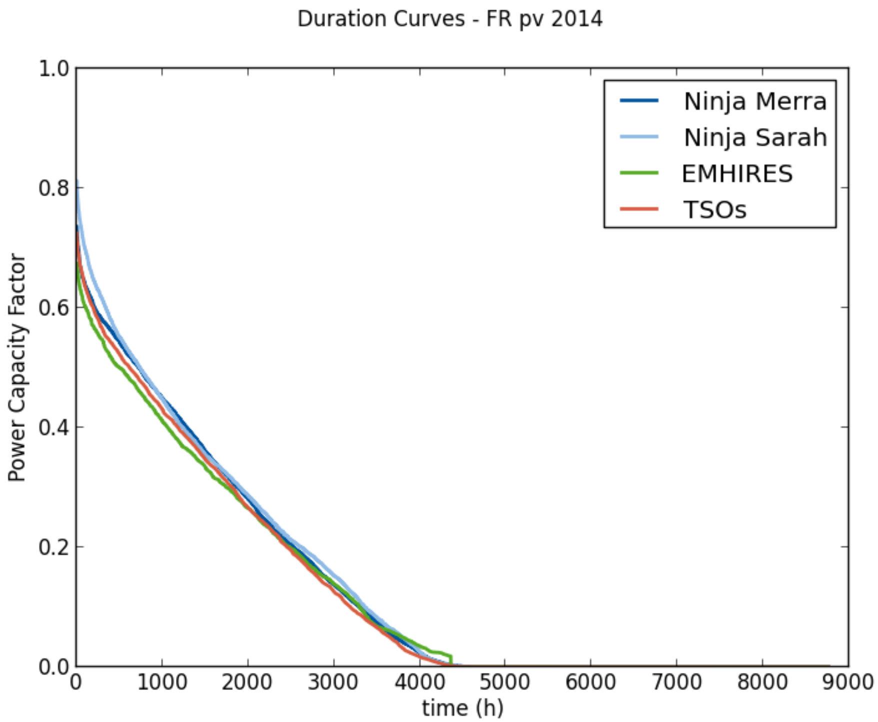
Power conversion model
- Power output of a panel is calculated using the relative PV performance model by [4] which gives temperature dependent panel efficiency curves

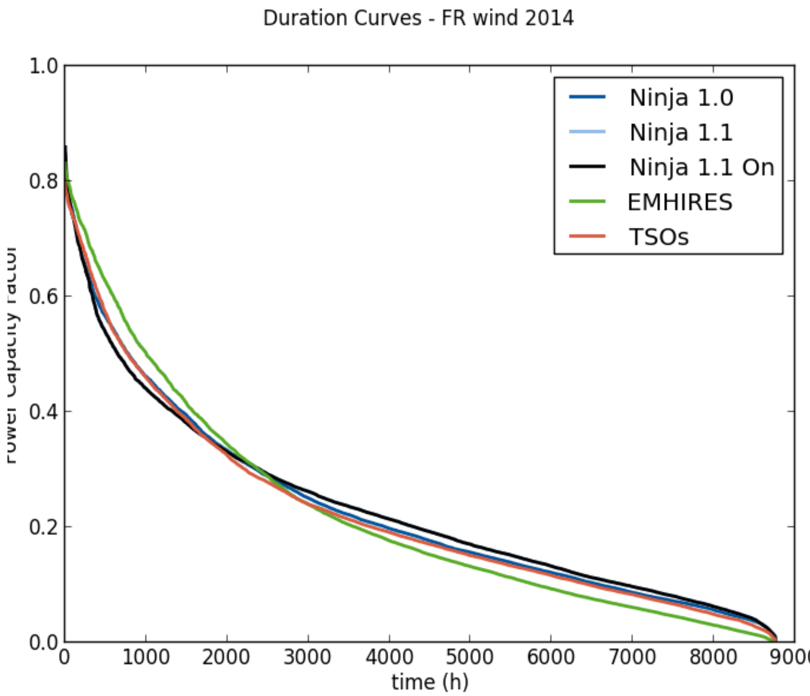
[1] Rienecker MM, Suarez MJ, Gelaro R, Todling R, Bacmeister J, Liu E, et al. MERRA: NASA's modern-era retrospective analysis for research and applications. J Climate, 2011;24(14):3624–48.
[2] Pierrot M. The wind power. Available from:http://www.thewindpower.net [March 20, 2018].
[3] Lauret P, Boland J, Ridley B. Bayesian statistical analysis applied to solar radiation modelling. Renew Energy 2013;49:124–7.
[4] Huld T, Gottschalg R, Beyer HG, Topič M. Mapping the performance of PV modules, effects of module type and data averaging. Sol Energy 2010;84(2):324–38.

Annex 7 – Representative year selection

Representative year selection	Closest year	2nd closest year	3rd closest year
Offshore Wind	2011	2012	2006
Onshore Wind	2006	2004	2012
Solar PV	2004	2006	2009
Overall year	2006	2012	2004
Overall error (absolute)	1.5%	2.4%	2.8%

Annex 8 – Renewables.ninja comparison with RTE’s





Annex 9 – Choice of LP instead of NLP

- This study performs a linear representation of the system.
- Non-linear constraints might improve accuracy, in particular when studying unit commitment, however they entail significant increase in computation time.
- Palmintier (2014): “ Linear programming provides an interesting trade-off, with little impacts on cost, CO2 emissions and investment estimations, but a speed-up up to x1500”.