Technical University of Denmark

42002 Modelling and Analysis of Sustainable Energy Systems using Operations Research

Final Project

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1 Student Contribution

The main student contribution is briefly summarized in the following table.

STUDENT	data collection	mathematical model & GAMS implementation	writing report
Sigurd	X		X
Lorenzo		X	X
Jorge	X	X	X
Ajinkya	X		X

2 Introduction

The following report aims to create a model in order to identify the optimal technology mix, according to a cost minimization, in a future energy system in the regions of North and South Carolina, in the USA. The competitiveness of different energy technologies is evaluated considering investment costs and production costs, along with variable costs, such as the ones related to fuel and emissions.
The collected data set is explained in **Section 3**, which is used in the mathematical model solved in GAMS, as in **Section 4**. Moreover, after discussing the results in **Section 5**, in **Section 5.B** the optimal power system configuration is analyzed on the basis of varying assumptions on fuel and emission prices and with the inclusion of a subsidy for offshore wind, i.e. the base model is tested against sensitivities. Later in **Section 6**, an extension is added to the model to evaluate the advantages of the implementation of hydrogen storage, which is used to compensate the variability of the renewable energy sources throughout the whole period and therefore increases their share in the optimal configuration. Concluding remarks are then be included in **Section 7**.

Regarding the modelling task of this assignment, it is important to point out that during the optimization of the technology mix for power generation there are many factors to consider. Through the implementation of initial assumptions, they become useful tools to get an understanding of how the technology mix can be optimized in the uncertainty that normally govern the power systems. It is important to remember that these models are, in fact, tools. Therefore, it becomes necessary to extensively test and analyze the results and check if the conclusions obtained from the model are realistic compared to the real world.

2.A North and South Carolina

The region analysed in this report is the Carolinas, which consists of two states: North Carolina and South Carolina. They are located on the east coast of the US, as shown in **Figure 1**. The reason behind this choice is the fact that it is one of the US regions showing room for improvement. A goal of reaching 12.5% share of renewable electricity generation by 2021 is set by the state of North Carolina [4] and is used as an optimization constraint in the base model.

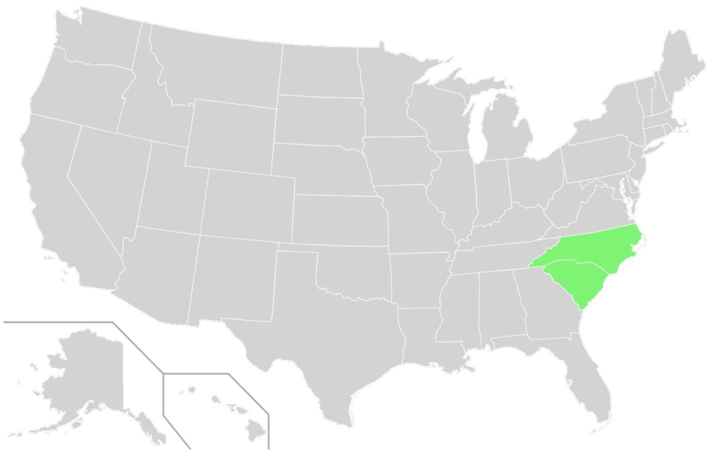
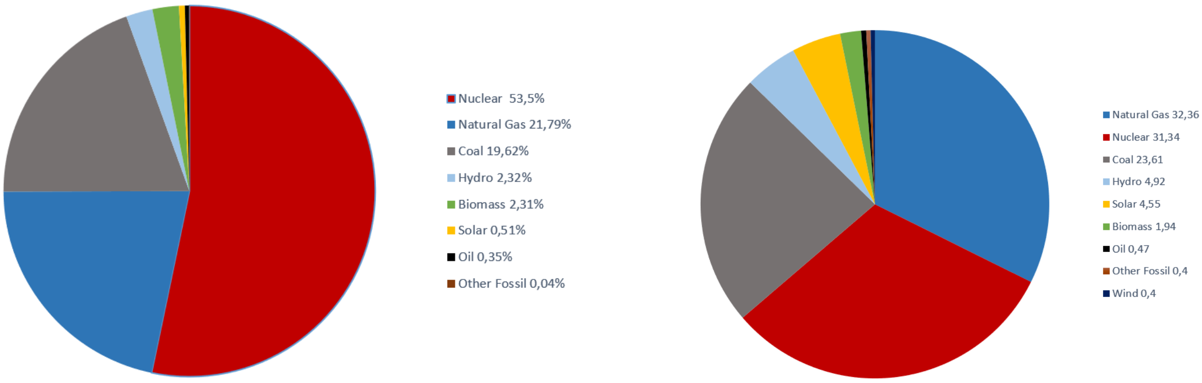


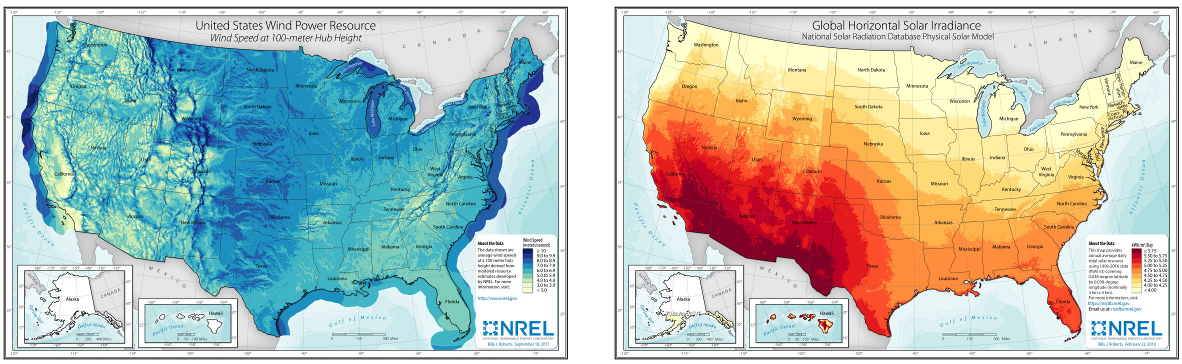
Figure 1: Map of the US - North and South Carolina[1]



(a) South Carolina [5] (b) North Carolina [5]

Figure 2: Electricity Generation by Source, North and South Carolina

As shown in **Figure 2**, the Carolinas' electricity generation mix is dominated by three main energy sources: nuclear, natural gas (CCGT) and coal, covering approximately 80-90% of the total generation, with a low share of renewables. It is interesting to note that North Carolina has the 5^{th} highest electricity generation from nuclear power in the US and South Carolina also covers more than half of its electricity production with it. The share of electricity generation from renewables in North Carolina is higher, compared to South Carolina, with solar and hydro being the biggest contributors. Both states are overlooking the Atlantic Ocean, which makes offshore wind energy an attractive source, as can be seen in **Figure 3a** [6].
Furthermore, the two states have a decent level of solar irradiance, which makes solar energy another possible alternative to cover the electricity demand in the region. Although the east coast doesn't have the same potential as the sunny west coast (as seen in **Figure 3b** [7]), solar power still has the possibility to have a bigger share in the electricity generation than what it has today, especially for South Carolina.



(a) United States Wind Potential Map - Wind Speed (b) United States Solar Potential Map - Irradiance

Figure 3: Wind and Solar Potential in USA

3 Data - Base model

The hourly demand profile in North and South Carolina was extracted from eia.gov [8] for year 2018, considering the variation during a whole year and the current energy mix. The hourly profile for PV, wind onshore, and wind offshore was then obtained from renewables.ninja [9], through the assumptions included in

PV	
Capacity	1 kW
System Loss	0,1
Tilt	35°
Azimuth	180°

Wind Offshore	
Capacity	1 kW
Hub Height	140 m
Turbine Model	Vestas V164 9500

Wind Onshore	
Capacity	1 kW
Hub Height	80 m
Turbine Model	Vestas V90 2000

Table 1: Assumptions for Data

It is important to mention that the data used for hydro power is referring to the total monthly hydro power production for North and South Carolina [10], transformed to maximum hourly generation. In the model, this value is assumed to be a monthly maximum hourly constraint throughout the whole period, due to the difficulty in finding enough data on the hydro power plants and storage. The monthly maximum hourly hydro power generation is shown in figure 4.

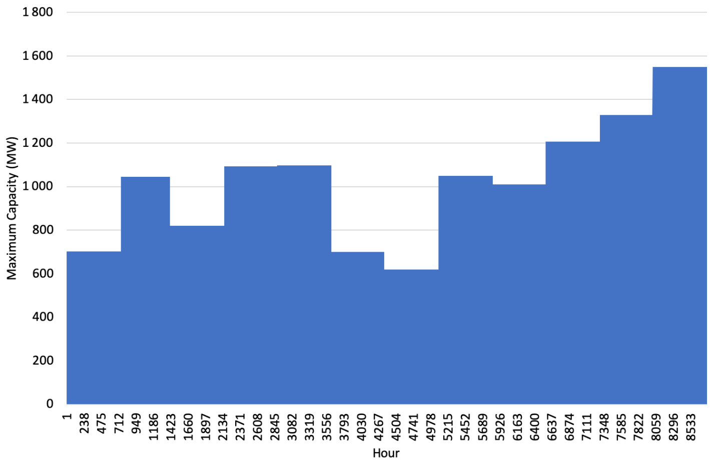


Figure 4: Maximum hourly hydro generation per month

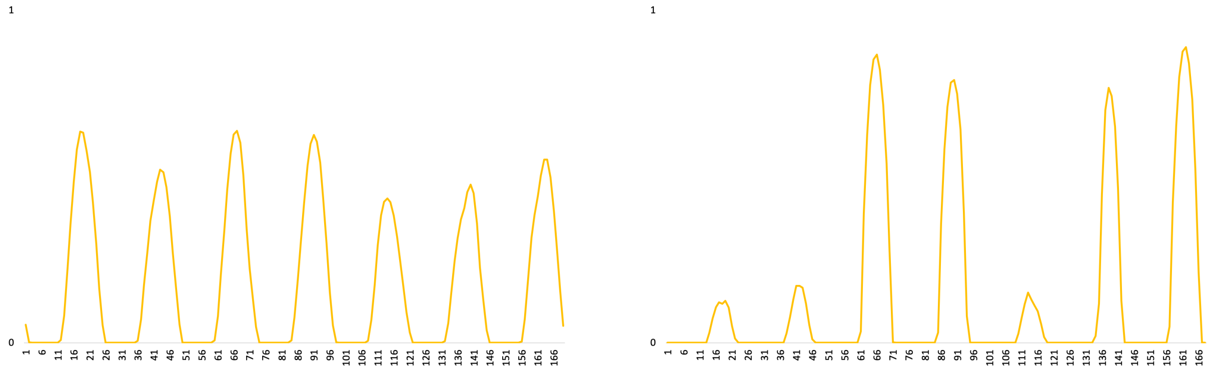
is also assumed that there is no fuel cost for the renewable resources (i.e. wind offshore and onshore, PV and hydro) and therefore also no fuel efficiency, which is instead defined as the overall plant efficiency for the conventional power plants. Moreover, the quantity of emissions for the renewable resources and nuclear are also assumed to be zero, so that the variable costs for renewable resources are only dependent on the variable O&M. However, renewable resources are known to have very low costs of operation and maintenance, which is the reason why they are assumed as zero except for hydro, even though it is still less than non-renewables.

The lifetime is then defined as the economic lifetime of the plants, corresponding to the time period during which an entity expects to be able to use an asset, assuming normal usage [11]. The variations in lifetime between the different technologies is based on literature, listed in **Section 8**. The rate of return is assumed to be 10% [12]. The data and technologies used in the model are listed in **Table 2**.

Table 2: Data set produced for input to the base model

Source	Investment cost [$/kW]	Fuel cost [$/MWh]	Variable O&M [$/MWh]	Fuel efficiency [%]	Quantity of emission [kg/MWh]	Lifetime [Years]
Coal	4 559.0	8.8	7.3	37.0	334.0	20
Nuclear	5 769.0	3.9	2.4	32.6	-	40
Wind Onshore	1 550.0	-	-	-	-	20
Wind Offshore	3 800.0	-	-	-	-	20
PV	1 250.0	-	-	-	-	20
Natural Gas	745.0	11.0	3.6	55.0	180.9	20
Hydro	2 027.0	-	1.4	-	-	40
Diesel	1 212.0	55.0	6.0	35.0	284.4	20

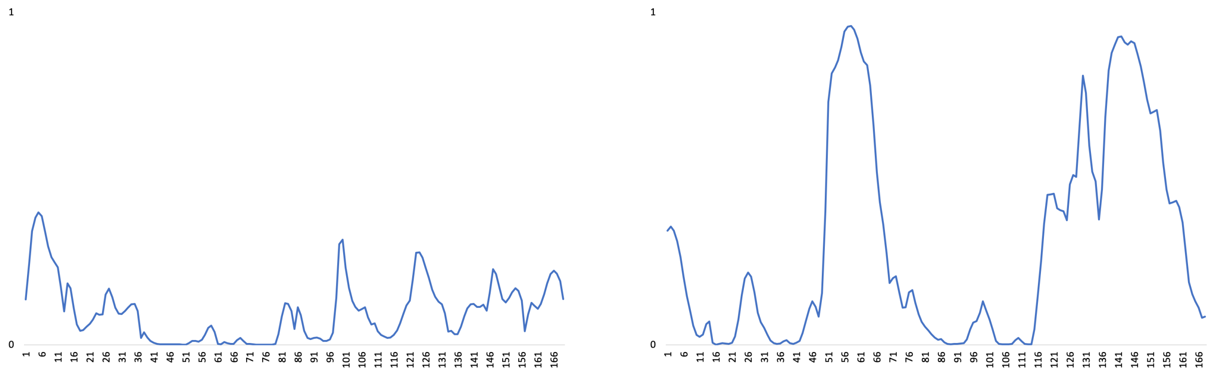
The hourly PV as well as onshore wind and offshore wind generation profiles for summer and winter are displayed below (**Figures 5, 6 and 7**), showing an evident fluctuation in the production, therefore possibly requiring the hydrogen storage, proposed in **Section 6**. Sources for data resources are listed in the Appendix.



(a) PV - Summer, week 25

(b) PV - Winter, week 1

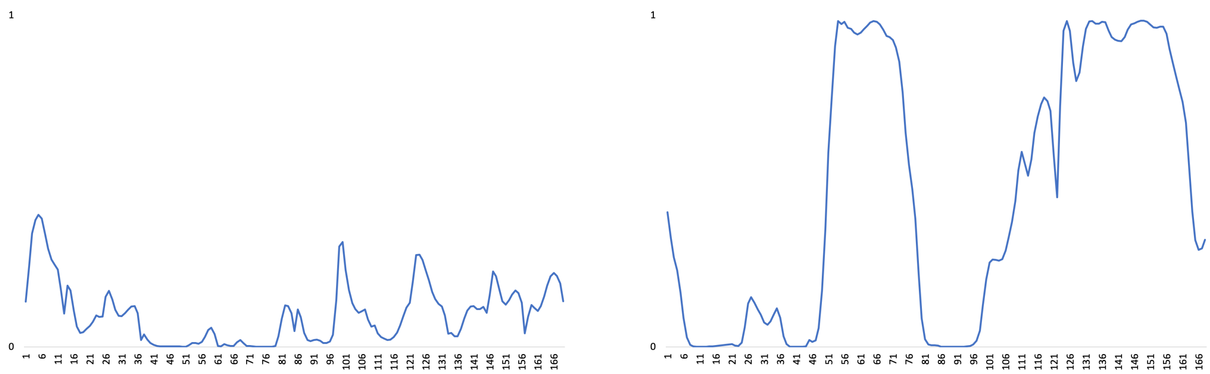
Figure 5: PV



(a) Wind Onshore - Summer, week 25

(b) Wind Onshore - Winter, week 1

Figure 6: Wind Onshore



(a) Wind Offshore - Summer, week 25

(b) Wind Offshore - Winter, week 1

Figure 7: Wind Offshore

4 Mathematical Model - Base Model

The mathematical model is formulated considering the implementation of solar, wind and hydro power as renewable sources plus the available non-renewable sources: coal, diesel, nuclear and natural gas.

Objective function The objective function that is expressed in **Formula 1**, evaluating both the total operational and annualized investment costs, will be minimized by the model.

$$\min \; Z = \sum_{t=1}^{T} \sum_{i=1}^{I} C_i \; P_{it} + \sum_{i=1}^{I} \left(CAPEX_i^{annualized} + OPEX_i \right) \; size_i \; X_i \tag{1}$$

where
$i = 1, ..., I$ number of technologies;
$t = 1, ..., T$ istants of time;
P_{it} is the production level of the technology i at time t;
$size_i$ is the fixed capacity of each unit of the different technology;
X_i is an integer variable defining the number of generation units installed;
$OPEX_i$ is the fixed operation cost for a unit of technology i;
C_i is the variable cost of the dispatchable technologies represented by the summation of the fuel, emission, and O&M costs as in **Formula 2**.
$CAPEX_i^{annualized}$ is the annualized cost of the investment for a unit of technology i, according to **Formula 3**.

$$C_i = \frac{C_{fuel}}{\eta_{fuel}} + C_{emiss} * \frac{q_{emiss}}{\eta_{fuel}} + C_{O\&M} \tag{2}$$

The optimal generation mix for different technologies is dependant on the fixed investment and the variable operational costs. The investment costs are paid for operating the capacity at every hour throughout the horizon. Since the planning horizon is very large as compared to the time periods, possibly resulting in a really big model, the costs have been annualized considering a rate of return of 10% [12].

$$CAPEX_i^{annualized} = CAPEX_i^{tot} \frac{r}{(1+r)[1-(1+r)^{-T}]} \tag{3}$$

where
r: rate of return of the investment;
T: lifetime of the technology.

Constraints The constraints are settled as follows:

- **Demand satisfaction.** The demand fulfillment is set as

$$\sum_{i=1}^{I} P_{it} = d_t - Pt^{solar} - Pt^{wind} \tag{4}$$

  It's important to highlight that the power produced by solar and wind energy, due to their variability, is always delivered at each hour, according to their availability.

- **Goal limit.** Since the current government is planning to reach the goal of 12.5% of renewables in the total energy share, the model is planned in order to overcome that quantity:

$$\sum_{res=1}^{RES} P_{rest} \geq d_t \cdot 12.5\% \tag{5}$$

- **Generation limits.** The minimum level of power generation is set at zero. On the other hand, the maximum is constrained through the implementation of an additional integer variable X_i, which evaluates the number of units built in that particular time t for each different technology, multiplied by the size of each one of them.

$$0 \leq P_{it} \leq size_i \; X_i \tag{6}$$

- **Minimum limits on variables.** All the variables are set as positive.

$$X_i, P_{it} \geq 0 \tag{7}$$

5 Results and discussion - Base Model

In this section, the initial results from the base model and the related sensitivity analysis will be presented and discussed accordingly.

5.A Initial results

5.A.1 Installed capacity

The power plants under consideration are - as described in **Section 2** - coal, nuclear, CCGT, diesel, hydro, PV, and wind onshore and offshore. The principal aim of the base model was to increase the share of the renewable energy technologies in the energy mix, while accordingly reducing the share of fossil fuels, focusing in particular on coal.
Figure 8 highlights the difference in the currently installed capacities of various power plants and the baseline generation from the optimized energy mix provided by the GAMS model. As shown in the figure, the share of the renewable resources has considerably increased, taking advantage especially of the solar potential mentioned in **Section 2.A**. The PV panels capacity installed is, in fact reaching almost 18 GW, in opposition to the actual scenario, in which it is providing only 4.3 GW. All the conventional plant capacities have been reduced, even though CCGT still remains the biggest in the system (19.8 GW), thanks to its constant availability at a lower price. Looking at the other renewables, hydro capacity is reduced from 4.5 GW to just 0.5 GW. While onshore and offshore wind, due to their huge investment costs, are not considered as a reliable source in the optimal mix, meaning that no wind turbines are installed.
The goal of 12.5% generation from renewables is achieved, but only due to the increased PV capacity, which becomes the dominant renewable technology in the mix. The high investment costs of wind farms, both onshore and offshore, are causing a complete neglection of the exploitation of the huge wind potential in this region, foretelling the possibility of finding a better solution in terms of emissions and clean energy production, maybe through a regulative intervention. The consequences of the introduction of a subsidy for the wind-produced energy are explained in **Section 5.B**.

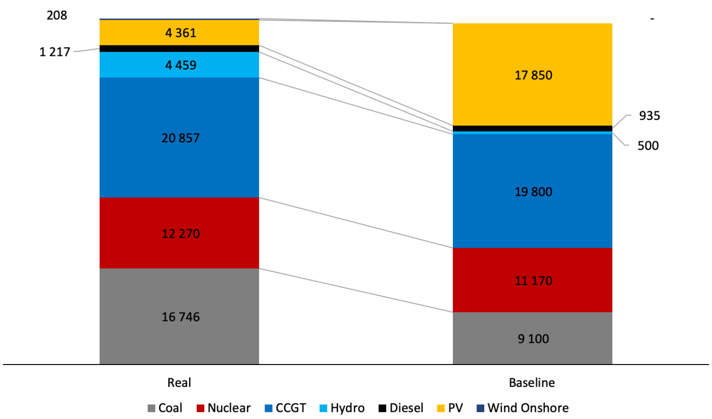
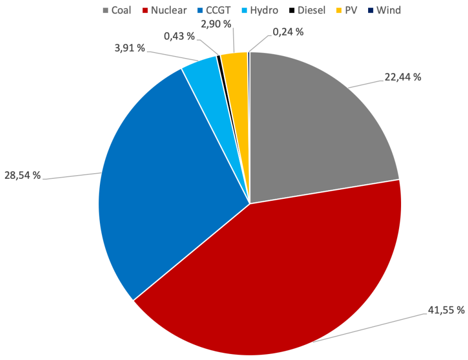


Figure 8: Installed capacity.

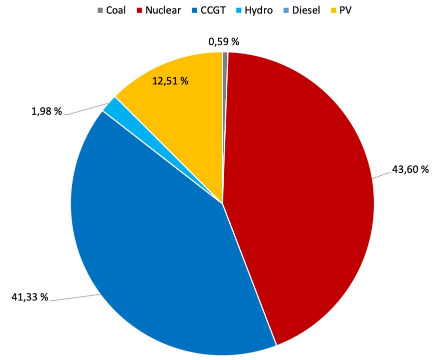
5.A.2 Yearly generation

The technological shares of the yearly generation are shown in **Figure 9**, comparing the real world scenario with the one provided by the model results. PV production is increased by almost 10% of the total generation, resulting in providing most of the energy coming from renewables, since hydro power is reduced and wind is not installed. CCGT in the optimal mix is contributing with 41.33% (the current real share is 28.54%) and it is increased in spite of coal, thanks to a generally lower cost required compared to it; together with nuclear, which remains almost constant in the two scenarios, they are providing more than 80% of the total generation.
Looking at the current situation, then, the model's generation pattern shows an increase in renewables

and a decrease in coal substituted by CCGT, which results in an important reduction of the emissions level, as shown in **Figure 11**.



(a) Real.

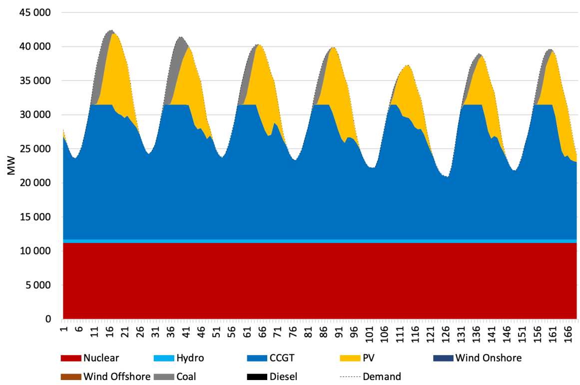


(b) Model.

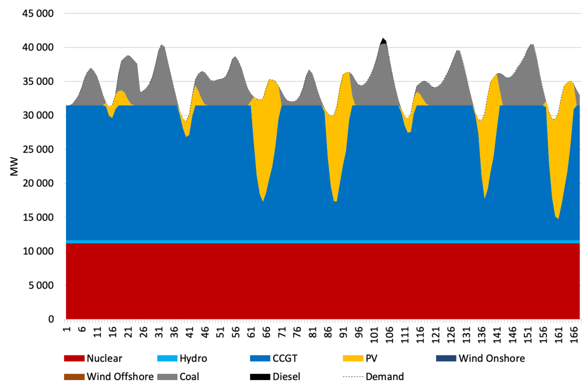
Figure 9: Real case vs model, yearly generation.

5.A.3 Weekly load

In **Figure 10** below, the production for two weeks of the year 2021 is shown. Figure 10a reflects the production for the week '25', representing the production from different technologies in the summer season, while Figure 10b reflects the production for week '1' and stands for the winter season.
The seasonal results show that nuclear and hydro are providing the base load for both summer and winter, with respectively 12.27 GW and 500 MW each hour, constantly throughout the whole period. CCGT plants are then working most of the hours at their full capacity, except for the peaks during day-time, during which solar power exploits its potential, especially during summer.
Moreover, coal and diesel are used only to supply the peak demand, working for very few hours during the overall year, but in different ways in summer and winter. The reason can be recognized in the lower production from solar during week '1', due to less favourable weather conditions compared to week '25', therefore requiring coal and diesel to provide energy. 9.1 GW of coal and 935 MW of diesel are then installed just to work during very few hours in the whole year, foretelling the possibility of improving the energy mix avoiding or at least reducing these capacities. One of the possible solutions is suggested further on in the report, through the implementation of hydrogen storage.



(a) Production week 25, summer 2021



(b) Production week 1, winter 2021

Figure 10: Generation mix winter vs summer.

5.A.4 Emission reduction

As seen in **Figure 11**, the quantity of emissions from CCGT is increased due to the increase in its generation. However, since CCGT is the least emitting of the fossil fuel sources, this increase is not very high compared to the reduction in the pollution from coal and diesel, which is almost completely removed. Therefore, the total amount of emissions is almost halved in the baseline scenario as compared to the current scenario.

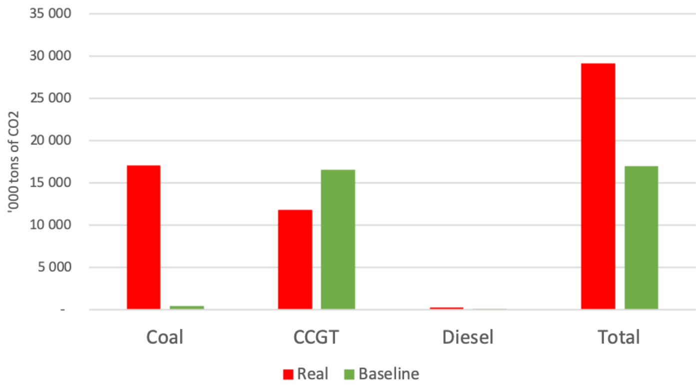


Figure 11: Emissions in kg CO_2 - current scenario vs basemodel

5.B Sensitivity analysis

Sensitivity analysis is performed for the base model. The parameters that are changed to investigate their influence on the technology mix are fuel cost, emission cost and offshore wind subsidies, and each one of them is separately increased step-by-step. The implementation of Production Tax Credit (PTC) for offshore wind production are based on PTC given for wind energy in the US, as reported by eia.gov to be 23 $/MWh [13].

Table 3: Sensitivity Scenarios

Scenario	Effect
FP25	25% Fuel price increase
FP50	50% Fuel price increase
FP100	100% Fuel price increase
EP25	25% Emission cost increase
EP50	50% Emission cost increase
EP100	100% Emission cost increase
S	23 $/MWh
S25	25% increase
S50	50% increase

The parameters chosen to operate a sensitivity analysis are based on the background of the results from the base model, where CCGT and nuclear are the two dominant producers and no wind is used at all. A change in the fuel cost and emission cost will influence the share of energy production of the conventional fuels, while making the costs for the emission and fuel free renewable resources relatively cheaper.
Since the wind potential is not exploited in the base model, another parameter interesting to investigate is subsidy for offshore wind production, to evaluate if its implementation will increase the capacity. As shown in **Section 2.A**, the wind potential is great especially by the coast of the Carolinas; therefore, the decision has been made to check if a production tax credit (PTC) for offshore wind production can be useful in order to increase the renewables share and reduce even more emissions.

5.C Sensitivity analysis - Results

5.C.1 Installed capacity

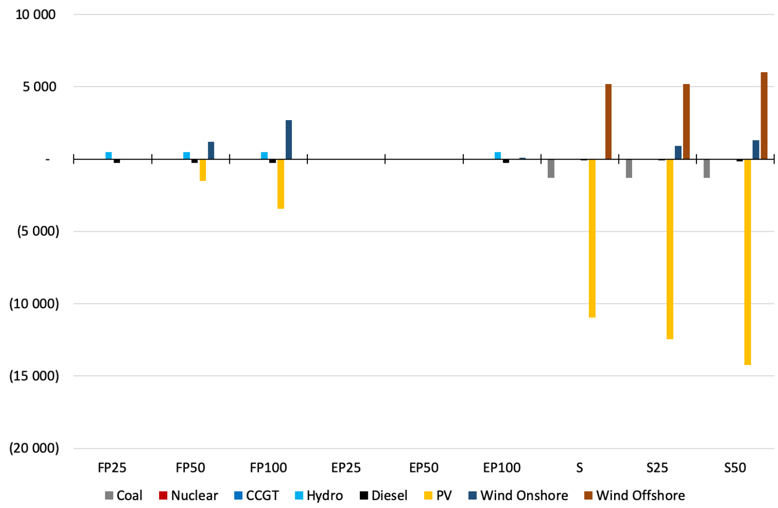


Figure 12: Sensitivity analysis - Installed capacity

The change in fuel price has little influence on the installed capacity, but there is an increasing tendency in varying the capacities installed when the fuel prices are rising, as shown in **Figure 12**. In fact, capacity for diesel and PV is reduced, whereas the capacity for wind onshore, as expected, increases along with hydro. This indicates that diesel, which has by far the highest fuel price, becomes less cost competitive in the market, while nuclear, CCGT and coal shares, due to their considerably lower fuel cost, remain at the same percentage as in the baseline.
On the other hand, when the price of CO_2 emission is increased, no changes are applied to the mix until the price increase reaches the 100% level, when the only notable variation is in the installed capacity of hydro and wind onshore, which is slightly increased with decreasing coal and diesel capacities.
The introduction of the subsidies for offshore wind has the most impact on installed capacity in the different scenarios. As expected, the installed capacity of offshore wind is drastically increased even for the first scenario (S), while the capacity of the conventional coal and diesel is reduced. However, since subsidies are given only for the offshore wind production, even PV generation will become more expensive related to wind (offshore and onshore), so that it will contribute for a smaller share of the total from renewables.
It is interesting to underline that even though the subsidies are given only for Offshore Wind, the installed capacity for Onshore wind also increases in a very small amount.

5.C.2 Generation

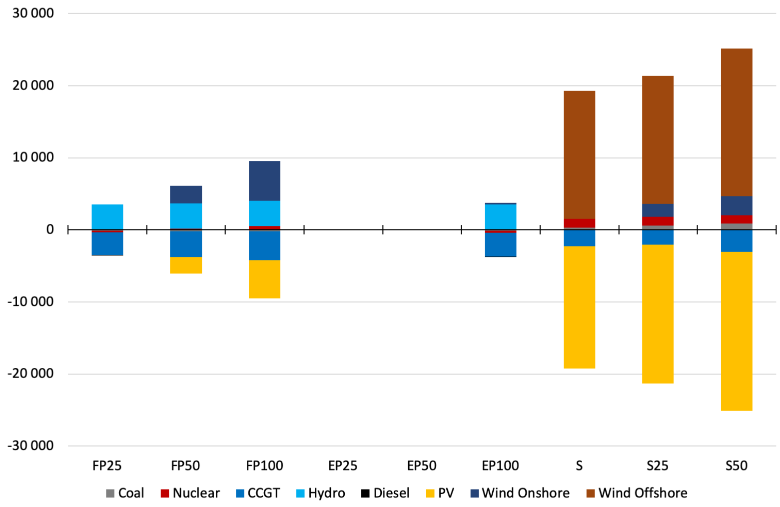


Figure 13: Sensitivity analysis - Yearly generation

The impact on generation (**Figure 13**) shows that the fuel cost has little influence even on the generation mix. The most obvious change is that PV production is reduced and replaced by wind onshore. As the fuel cost increases, the cost of wind gets cheaper relative to conventional power, and therefore the generation mix is spread more evenly between PV and wind onshore. CCGT is reduced a bit, as the total share of renewable has increased. No offshore wind is generating at all even with 100% increase in fuel price, since the high investment costs are not influenced. The increase in emission price has little impact on the generation as well: conventional generation decrease a bit while hydro increases.
On the other hand, when wind subsidies are introduced, the production is changed quite a lot from the baseline as wind onshore and offshore becomes a part of the energy mix. Solar production is decreasing a lot which is in line with the reduction of solar capacity. Coal and nuclear production increases, while CCGT decreases.

5.C.3 Emission reduction

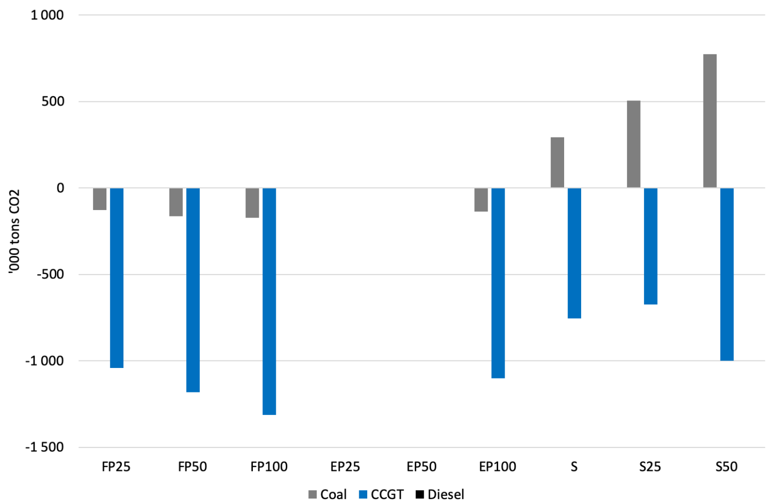


Figure 14: Sensitivity analysis - Emissions

Figure 14 shows that the fuel price has a great influence on the quantity of emissions, strictly correlated to the energy production of the fossil generators. The reduction in emission from CCGT and also for coal are quite significant. The emissions from coal and CCGT decrease further when fuel prices increase,

but the most significant change in emission reduction is from base line to FP25. The diesel emissions are also reduced, but very little compared to CCGT and coal, and it is therefore not visible in **Figure 14**. The price of emission shows almost no influence on the quantity of emissions, except for the EP100, where coal and CCGT considerably reduce the amount of emissions.
Instead, there is an impressive reduction in emissions with the introduction of subsidies in all three scenarios, especially from CCGT, which reduces production, while there is an increase in the ones from coal compared to the baseline. However the emission reduction is highest for the first S-scenario and lowest for the S50-scenario, which indicates increasing subsidies from S to S-25 and S-50 for offshore wind do not corroborate the scope of a more clean energy mix.

5.C.4 System cost

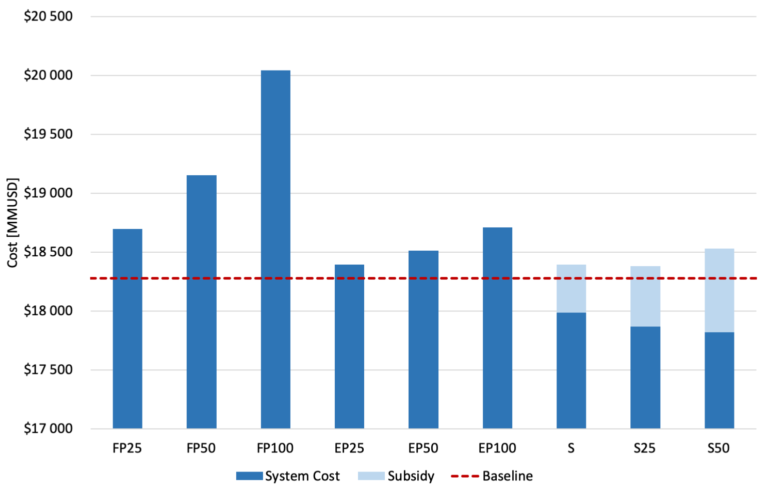


Figure 15: System cost.

Figure 15 displays the total system cost of the different scenarios compared to the baseline. Looking at the fuel prices, It is clear that, even though the emissions decrease, the total energy system cost increases a lot. This might indicate that it is not economically feasible to increase the fuel price in order to mitigate CO_2 emissions from conventional power. However, in the future, it may become a reliable type of regulation in tragic situations, maybe in case of requiring a drastic reduction of emissions irrespective of the costs. In that case, fuel price increase is an effective solution, as it is the scenario with the biggest CO_2 emission reduction.
The total system costs are rising even with the increase of the emission costs, although resulting in a lower value compared to the fuel price scenarios, but the reduction in emission is also less. Moreover, since there is no reduction in emissions before the emission cost is doubled, an increase of 25 and 50% should not be considered as sufficient quantities in order to apply this regulation.
On the other hand, varying the subsidies, the system cost is generally lower than the other sensitivity analysis scenarios, but still remaining more expensive than the baseline. The system cost is slightly increasing when increasing subsidy level, but is cheapest for the S25-scenario. However, since S25 and S50 are also the scenarios with the least CO_2 reduction, subsidies should not be considered as a reliable solution in order to achieve a lower level of pollution; they are, in fact, helpful only for the goal of creating a greater and better mixed production from renewable sources, in order to harness both the huge solar and wind potential.

6 Model extension

To make the system more flexible and less reliant on CCGT and nuclear, as well as avoiding the installation of coal and diesel power plants, the extension chosen to be implemented in the model is the hydrogen storage. Hydrogen will be produced through electrolysis, then compressed and stored, and fuel cells will be used to convert it back to electricity. Proton-exchange membrane (PEM) electrolysers and PEM fuel cells are the chosen technologies, due to their quick start up time and relatively cheaper price compared to solid oxide fuel cell/electrolyzer [14].
In the model, the energy content of hydrogen used for the calculations is 119.93 MJ/kg and density of hydrogen is 0.08375 kg/m^3 [15] .

6.A Hydrogen

Hydrogen is dubbed by many as an important energy carrier in the future energy systems. It is one of the most abundant elements available and quite easily produced by an electrochemical process, called electrolysis. Depending on the chosen type of technology (PEM, alkaline, solid oxide etc.), electricity is used to split water in different ways, producing hydrogen and oxygen gas. Then, the hydrogen gas is compressed and stored and can be later used for gas-to-power, fuel upgrading or as fuel in a fuel cell, reversing the previous reaction. Hydrogen can also be used for industrial applications, as seen in **Figure 16** [2]. One of the advantages of this technology is that the only waste product in this case is water, which is non-toxic and easy to handle.

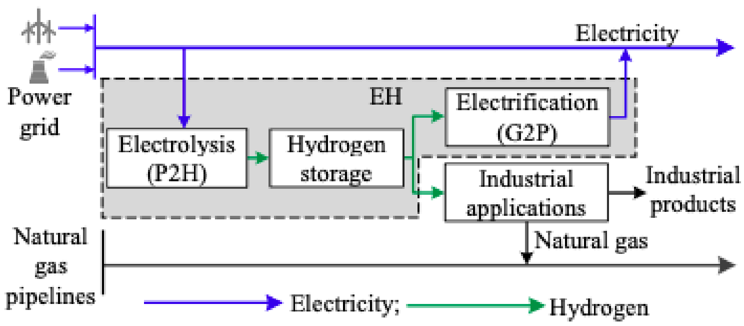


Figure 16: Example of hydrogen production and storage in an energy system [2].

Combining fuel cells and electrolyzers creates an opportunity for storing excess electricity in the form of hydrogen. As seen in **Figure 17**, excess electricity, for example from fluctuating wind or solar, is used to produce hydrogen, which can be stored so that, when electricity is needed, it can be used as fuel in a fuel cell to produce electricity. This kind of electricity storage provides flexibility for the grid, and can contribute to reduce the dependence on fossil fuels.

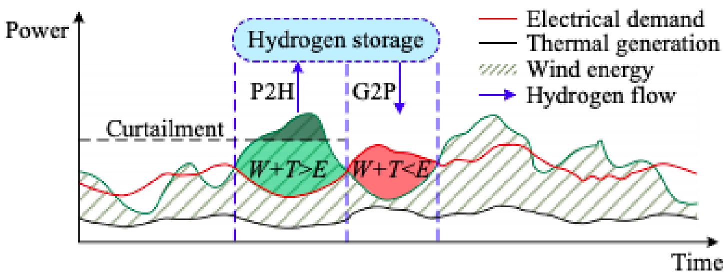


Figure 17: Example of hydrogen production and storage in an energy system with fluctuating wind production. P2H - power is used to produce hydrogen; G2P - hydrogen is used as fuel to produce power [2].

However, the major disadvantages of this energy storage technology are the fact that there are considerable losses in the production and consumption processes [16] and the difficulties concerning the storage properties such as high pressure, which requires energy intensive compression. High costs are also an issue, but a lot of research is being done in this field in order to be cost-effective; in particular the price for alkaline electrolyzers is getting closer to being competitive in the market, compared to other storage technologies [14].

6.A.1 Data - extension

The hydrogen storage is split in two parts, charging and discharging. The whole new component is shown in **Figure 18** and it is described in the following paragraphs.

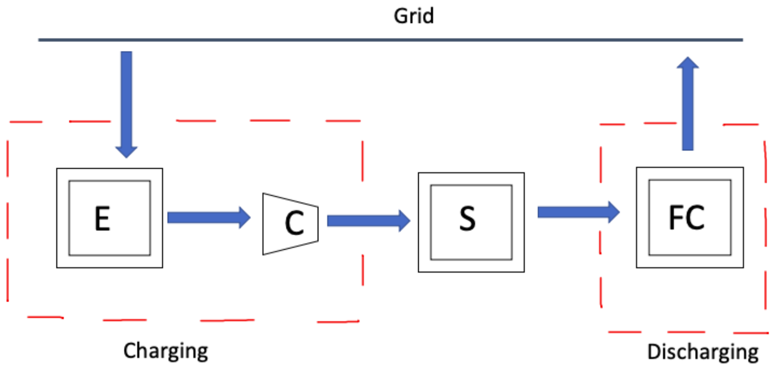


Figure 18: Hydrogen storage overview, charging and discharging

Charging unit The charging unit consists of the electrolyzer and the compressor. When charging, electricity will be taken from the grid to produce hydrogen via electrolysis (E), and then it will be compressed (C) and stored in the storage unit (S). The hydrogen will be kept in the storage until discharging is needed. The efficiency of the charging unit is therefore a combination of the ones of the electrolyzer and the compressor, but for simplification this model will only consider the efficiency of the electrolyzer. Thus, the charging efficiency is equal to 58% [17].
The investment cost for the charging unit is the investment cost for the electrolyzer, as the cost of the compressor is neglected for simplification. The annualized capital cost of the electrolyzer is 145 219 $/MW [17].

Storage unit The physical storage unit is assumed to be a large scale underground cavern, as shown in **Figure 19** [3], which in reality would limit the technology to certain areas due to its geographical properties. In this report the geographical aspects are not taken into account, therefore the technology can be applied anywhere.
The annualized investment cost for the storage is 1 777 $/MW, and the fixed O&M is assumed to be zero [18]. It is also assumed there are no losses in the storage.

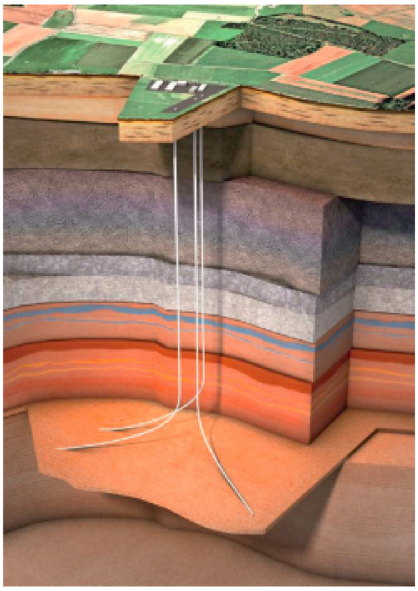


Figure 19: Underground hydrogen storage [3]

Discharging unit The charging unit is the fuel cell (FC), which has an efficiency of 50% [19]. The annualized investment cost and fixed O&M are a bit higher than for the elecrolyzer, at 172 111 $/MW and 72 000 $/MW respectively. The fuel cell capacity is much lower than for the electrolyzer, which explains the higher cost per MW. Fuel cells are yet to be implemented at large scale in the market due to the need for expensive materials [20], and limited data is available about large scale operation, such as it is intended in this project.

The data used for the extension in the model is listed in **Table 4**, and further data references are listed in appendix, section 8.

Table 4: Data set for model extension

	Electrolyzer	Fuel cell	Storage
Overall efficiency [%]	58	50	100
Lifetime [years]	15	15	30
Annualized investment cost [$/MW]	145219	172111	1177
Fixed O&M [€/MW]	61000	72000	0
Size [MW]	10	0.1	10

6.A.2 Mathematical model

In order to adapt the model to the installation of a hydrogen storage, some changes have to be made, since the base model previously provided in the report is building as the capacity of the different technologies (included RES) the exact quantity required to fulfill the demand in the optimal way.
In addition, as already explained, the hydrogen storage can be considered as a battery, in which the electrolyzer and the compressor correspond to the "charging unit", while the fuel cell is the principal component of the "discharging unit". Between them, an hydrogen storage is getting filled and emptied with a particular charge and discharge level. Therefore, the changes are the following:

- **New variables.** The new variables added for the system are S_k, which indicates the number of charging, discharging and storaging units, μ_t^- and μ_t^+, which instead represent their charged and discharged energy level.
- **Objective function.** The objective function is updated according to the investment and operational costs of the hydrogen implementation, adding **Formula 8** to the base model equation.

$$minZ = ... + \sum_{k=1}^{K} \left(CAPEX_k^{annualized} + OPEX_k\right)\ size_k\ S_k \tag{8}$$

in which:
$k = 1, 2, 3$ number of the different block of the hydrogen implementation;
$CAPEX_k^{annualized}$ is the annualized cost of the investment for a unit of k;
$OPEX_k$ is the fixed operation cost of a unit of k.

- **Demand constraint.** In **Formula 9** the demand constraint is modified considering the discharging power:

$$\sum_{i=1}^{I} P_{it} + \mu_t^- - \mu_t^+ = d_t - Pt^{solar} - Pt^{wind} \tag{9}$$

in which:
μ_t^- is the discharging level of the all units;
μ_t^+ is the charging level of the all units.

Then, new constraints are added:

- **Charging and discharging capacity level.** Both levels of the different units are constrained to a minimum quantity of zero, while, for the maximum, the charged energy is set according to the maximum energy provided by the renewable energy sources and the discharged one assumes as maximum the quantity in the storage (multiplied by the efficiency).

$$0 \leq \mu_t^+ \leq S_{k1} \ (Pt^{solar} + Pt^{wind}) \tag{10}$$

$$0 \leq \mu_t^- \leq S_{k3} \ l_t \ \eta^- \tag{11}$$

in which:
S_{k1} is the number of charging units;
S_{k3} is the number of discharging units.

- **Hydrogen storage level.** The level of the storage at instant t considering the level at the previous t and the charging/discharging level at the instant $t-1$, as in **Formula 12**.

$$l_t = l_{t-1} - \frac{\mu_t^-}{\eta^-} + \mu_t^+ \ \eta^+ \tag{12}$$

in which:
l_t and l_{t-1} are the levels of the storage at the instant t and the previous $t-1$;
η^- is the efficiency of discharging;
η^+ is the efficiency of charging.

- **Storage level limit.** The storage level is constrained as shown in **Formula 13**.

$$0 \leq l_t \leq S_{k2} \ l_t^{max} \tag{13}$$

in which:
S_{k2} is the number of storage units;
l_t^{max} is defining the size of a single unit of storage.

- **Minimum limits on variables.** All the variables are then set as positive.

$$S_k, \mu_t^-, \mu_t^+ \geq 0 \tag{14}$$

6.B Results and discussion - Extensions

6.B.1 Installed capacity

Figure 20 shows the comparison between installed capacities for different technologies in the real case, baseline and the extension case with hydrogen storage implemented. Compared to the baseline, coal capacity is almost halved from 9 100 to 5 850 MW, while CCGT and nuclear remains the same with hydrogen storage implemented. Diesel capacity is increased with 255 MW, and hydro power has doubled its capacity from 500 to 1 000 MW. The biggest change in capacity is for PV, which is reduced from 17 850 to only 9 300 MW, still more than doubled compared to the real case. Some of the PV capacity has been replaced with wind onshore power, which has gone from zero installed capacity in the baseline to 6

600 MW in the extension.
The total installed capacity is therefore reduced of 4 445 MW compared to the baseline, which is a result of a more flexible system where less peak capacity is needed due to the introduction of hydrogen storage. Thus, hydrogen storage take up the place for the extra units.

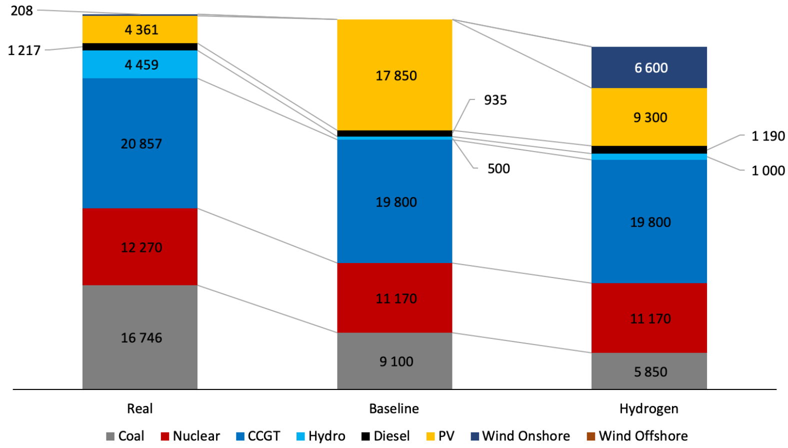


Figure 20: Installed capacity, base model and hydrogen extension.

6.B.2 Yearly generation

Figure 21 shows the distribution of yearly generation between the different technologies for the real case, the baseline and for the hydrogen storage. The baseline and hydrogen case are quite similar, except that the renewable share are more evenly spread between hydro, PV and wind onshore for the hydrogen case, while in the baseline PV is the dominant. The amount of CCGT is also reduced a bit with the hydrogen case relative to the baseline, and thus renewable generation is increased a bit. Both nuclear and coal production has increased a small portion in the case with hydrogen storage compared to baseline. Diesel generation is also increased in the hydrogen case, however the portion of diesel is very small in both the baseline and the hydrogen case, and thus not viewable in **Figure 21**.

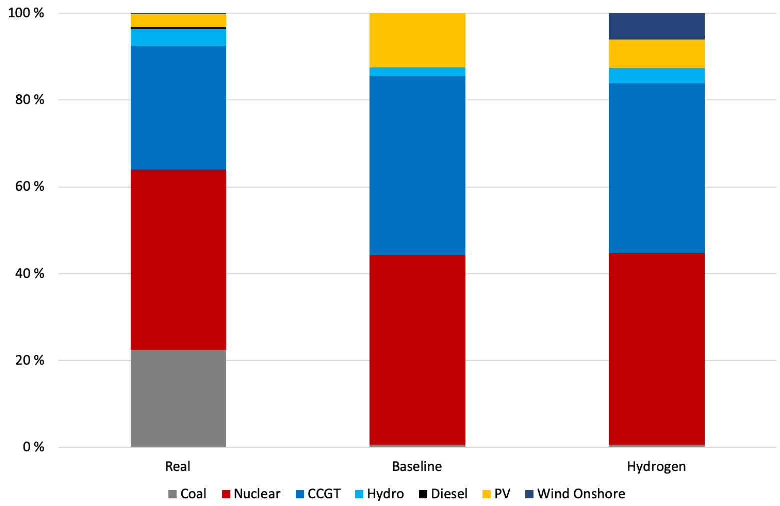
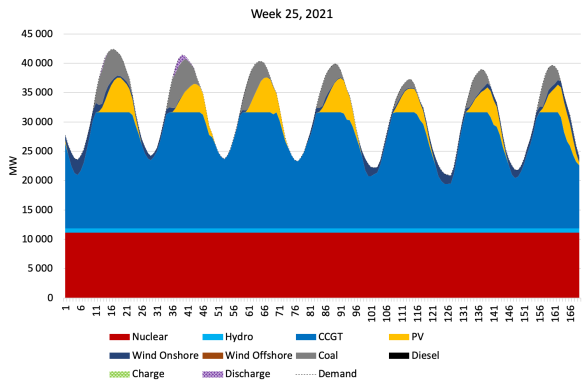


Figure 21: Yearly generation real, base model and hydrogen extension.

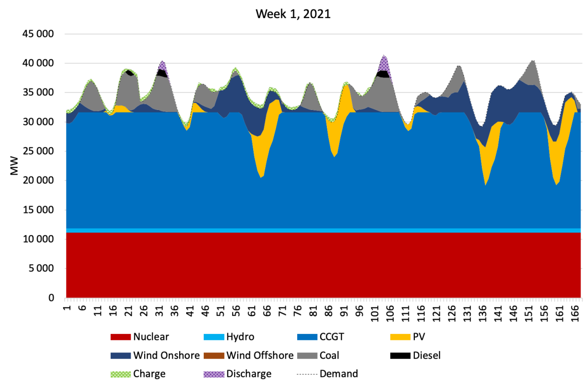
6.B.3 Weekly load

Figure 22 shows the weekly load for a week during summer and a week during winter when hydrogen storage is implemented in the energy system. The difference from the baseline model is that now discharging and charging of a storage is included, and thus improves the flexibility of the system. The

system discharges the storage at the highest peaks, which is the intention of the storage.
Furthermore, as seen in **Figure 22b**, there is more diesel production during the winter period than in the baseline, but less coal. The share of wind onshore production is greatly increased compared to the baseline, while PV is reduced.
The summer period, **Figure 22a**, instead, is quite similar to the one displayed for the baseline, even though less solar power is produced while onshore wind is contributing more, as is coal. Some discharging takes place during the peaks.



(a) Production week 25, summer 2021.



(b) Production week 1 2021, winter.

Figure 22: Mix winter vs summer with hydrogen.

6.B.4 Emission reduction

Figure 23 shows the total emission of the real system, the baseline and baseline with hydrogen storage. The figure shows that the total system emission is less with hydrogen storage implemented than the baseline, and thus implementing hydrogen storage to the energy system reduces emissions and make the system more environmentally friendly.

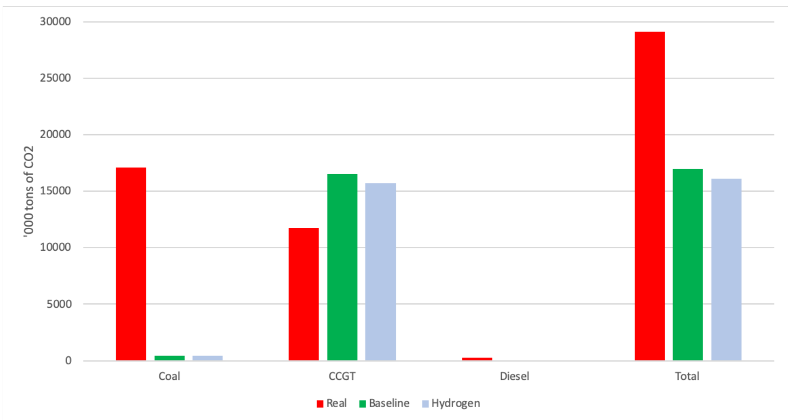


Figure 23: Reduced emission.

6.C Sensitivity analysis - Extensions

Based on the results obtained from the extension, the parameters decided to look further into for sensitivity analysis for the extensions are investment costs of the hydrogen implementation, fuel price and subsidies on offshore wind. The emission price variation is not considered anymore, since in the base model sensitivity analysis showed its low influence on the system. The change in fuel cost and subsidies on offshore wind is implemented in the extension just as in the base model sensitivity analysis. The variation in investment cost for the hydrogen implementation is based on the values for 2030 and 2050 reported by [17]
All the graphs below are in comparison with the new base model, extended with the implementation of the hydrogen system.

6.C.1 Installed capacity

Figure 24 shows the sensitivity analysis on the extension in terms of the installed capacity variations of the different technologies under consideration. The decrease in the investment cost for the hydrogen system shows a change in the installed capacities for the PV and onshore wind; however, the biggest advantage is the reduction of the coal plants, pointing out the capability of the system to be more adaptable with the availability of a storage. Looking at fuel price variation, it can be clearly seen that, as it increases, the installed capacity of PV shows a slight increase in spite of onshore wind, which is decreasing. Both of the variations remain constant in the three different scenarios, showing very little correlation with the price increasing.
Then, with the introduction of subsidies on Offshore wind, an obvious increase is seen in its installed capacity, while both solar and onshore wind shows a huge decrease. Moreover, from the sensitivity analysis on the subsidies the major outcome is that subsidies act as a very good incentive for introducing offshore wind into the energy mix in the presence of hydrogen storage as well in its absence. It is worth noting, however, that in the base case, introducing subsidies showed a decline only on the installed capacities for the PV; instead, when hydrogen storage is introduced in the system, also the installed capacity for onshore wind is declining, due to a more optimized energy mix.

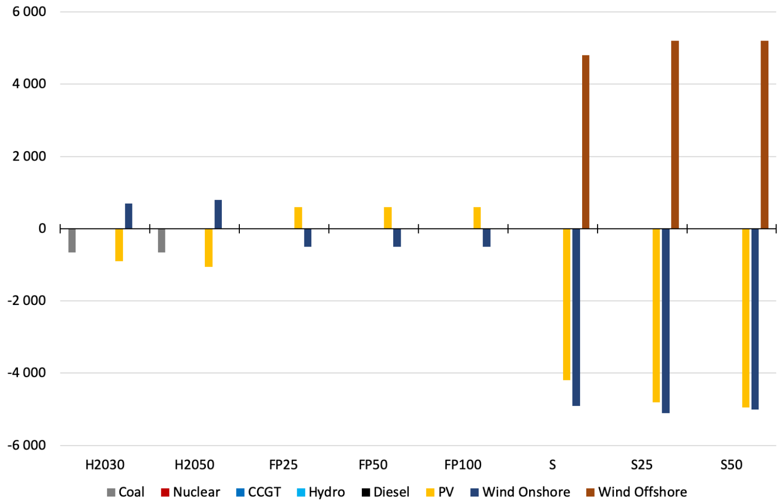


Figure 24: Sensitivity analysis on extension - Installed capacity

6.C.2 Generation

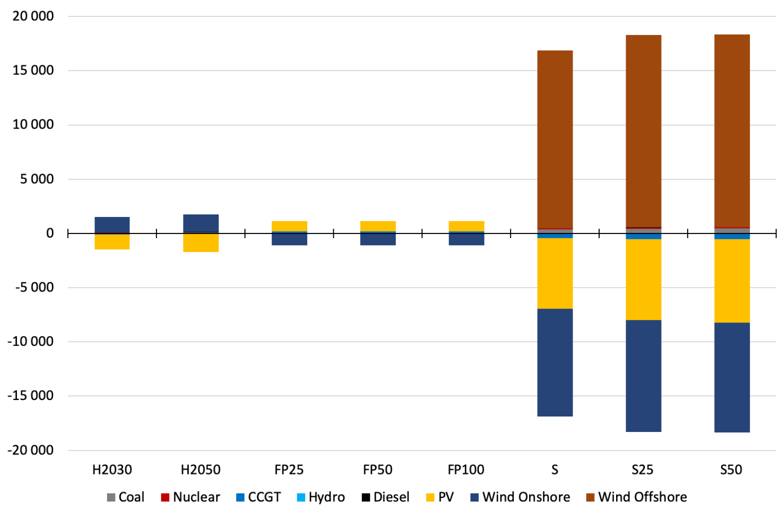


Figure 25: Sensitivity analysis on extension - Generation

In **Figure 25** the generation mix is compared between the different scenarios. The decrease in investment cost for the storage system has little influence on the generation: the only notable change is that PV is reduced a bit and replaced by wind onshore, as it was for the capacity, and coal generation is decreased.
Moreover, fuel price increase has little influence on the generation, only a small portion of PV is increased while some onshore wind is slightly decreased. There is no change in the generation between the different fuel price scenarios (FP25, FP50 and FP100), showcasing that the fuel price has little influence on the generation. The introduction of wind offshore subsidies shows similar results as for the baseline, where PV is reduced and replaced by wind offshore, although wind onshore is also strongly reduced in the hydrogen case, while wind offshore was slightly increased in the baseline case with subsidies. The subsidies gives the biggest impact on the generation profiles of all the scenarios.

6.C.3 Emission reduction

figure 26 shows the sensitivity analysis on the extensions and highlights the emission variation between the different scenarios.
With reduction in the investment cost for hydrogen, emissions increase correspondingly, because of the fact that the hydrogen system units (electrolyzer, storage and fuel cell) installed as more, so that there's more availability of installing more renewable sources. Unfortunately, increasing too much the generation from PV & Wind, requires more flexibility from the system, in order to compensate their variability, which can't be provided completely by it. The reason behind that can be found in the limited capability of charging and discharging, so that a lot of energy coming from renewable sources is still going to be wasted and not stored.
On the other hand, looking at fuel cost variation, emissions are decreased due to a greater cost of conventional plant, even though all the three scenarios of the increased price achieve almost the same quantity reduced.
In the end, the introduction of the subsidies has the same impact as the decreased investment costs for the hydrogen storage on the emissions, as emissions are increased, and much more than any of the other scenarios. The emissions, from coal in particular, show a steady rise with the introduction of subsidies, because of the increased wind offshore capacity and generation which requires, again, more contribution from conventional plants to satisfy the demand while there is no availability of renewable energy. The emissions from coal increases a lot, due to the fact that it is the cheapest technology that can be used during the load peaks. Diesel emission is increased in all the scenarios in the sensitivity analysis, and so is emissions from CCGT.

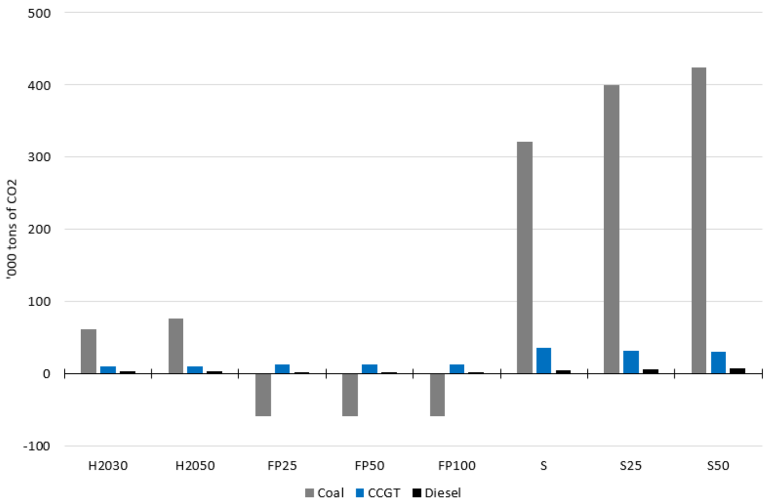


Figure 26: Sensitivity analysis on extension - Emission level

6.C.4 System cost

The sensitivity analysis impact on the system costs is shown in **Figure 27**. The hydrogen base case (yellow horizontal line) has lower cost than the original baseline cost (red horizontal line), as less total capacity is installed and thus investment costs are lowered. It can be seen that, when the investment cost for the hydrogen system is reduced, the total system cost is obviously less than the base model case and the standard extension case. Thus, an technological development within hydrogen technologies in the future could help reduce both emission and system cost. When the fuel costs are increased to FP25, the total system costs are lower than the base model case but higher than the standard extension case. From a general point of view, the scenario with FP25 can be the best one for implementation, because the total system costs are lower than the base model case and emission reductions for coal are also observed for this scenario. The introduction of subsidies gives a lower system price than the baseline case, but more expensive compared to the extension base. Bearing in mind the subsidies lead to significant increase in emission, and is more expensive than the extension base line, subsidies on wind offshore should not be a recommended method. As in the baseline case, there is an question of importance of emission reduction and price reduction: which is more important is difficult to decide.

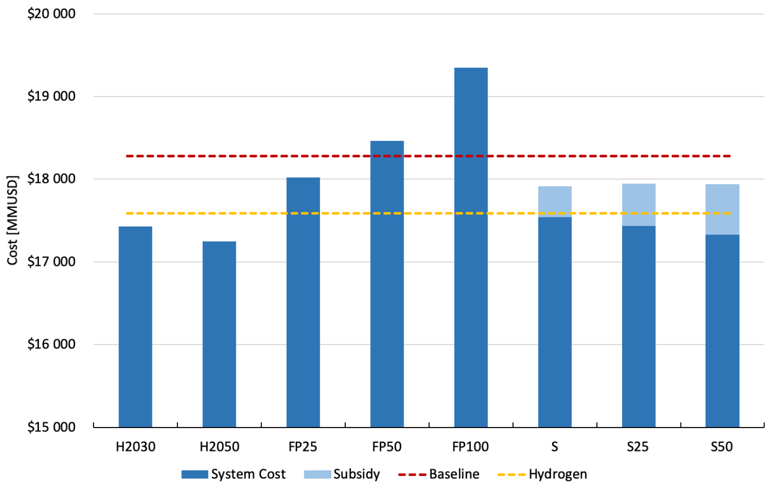


Figure 27: Sensitivity analysis on extension - System cost

7 Conclusion

The report gives an insight into how an energy system can be optimized, with focus on an increase in renewable energy generation at the lowest cost. The region chosen to focus on is North Carolina and South Carolina, on the east coast of USA, with low share of renewable electricity generation and heavy dependency on mainly coal, natural gas and nuclear generation. A goal of reaching at least 12.5% renewable electricity generation within 2021 is set by government of North Carolina, and has been used as a goal to overcome in the model created.

The initial results provided by the model showed a significant increase in renewable capacity in the region, especially for PV. This resulted in a reduction in CO_2 emission. Further sensitivity analysis performed on the model showed that an increase in fuel prices reduced emissions considerably, while also increasing the cost. Introducing subsidies for wind offshore production gave a less expensive solution, but also with much less emission decrease. Changing emission cost had little influence on installed capacity, generation emission and system cost.

Implementing hydrogen storage provides flexibility to the system and gives a lower system cost due to less installed capacity required, as well as reduced emissions. Furthermore, decreasing investment cost for the hydrogen storage reduces total system cost, which means a development within the technology through R&D could help reduce costs of future energy systems. Increasing fuel prices with the hydrogen storage reduces emissions, and it is the most effective emission reduction solution, even though more expensive. Introducing subsidies on wind offshore production increases cost and emissions, and should not be considered as an optimal solution.

8 Appendix

8.A Data Sources

Table 5: Data references

Data	References
Conversion of units	[21]
Energy demand profiles	[8]
Data for PV, wind onshore and wind offshore	[9]
Quantity of emission for coal, diesel and natural gas. Average of the four coal types is used	[22]
Fuel cost for coal, natural gas and diesel	[23]
Fuel cost for nuclear	[24]
Investment cost for conventional energy sources	[25]
Emission cost	[26]
Fuel efficiency coal	[25] & [27]
Fuel efficiency nuclear and natural gas	[25]
Investment cost for renewable sources and lifetime of renewable and conventional plants	[28]
Lifetime of coal plant	[29]
Lifetime of hydro power plant	[30]
Hydro power production	[10]
Rate of return	[12]
Lifetime of nuclear plant	[31]
TPC wind	[13]
Lifetime of natural gas and diesel plant	[32]
Lifetime of solar and wind plant	[33]
Electrolyzer efficiency, lifetime, O&M and capital cost	[17]
Hydrogen storage capacity, size, lifetime and capital cost	[18]
Energy content and density of hydrogen	[15]
Fuel cell capital cost, size, lifetime and capacity	[19]
Fuel efficiency diesel	[34]

8.B Results

The modelling results are shown on the following tables. Note that (H) refers to the hydrogen case, the base model extension with hydrogen storage.

Table 6: System prices for different scenarios

Scenario	System price [M$]	Scenario	System price [M$]
Baseline	18 277	**-**	-
H	17 586	**FP25**	18 697
H2030	17 429	**FP50**	19 150
H2050	17 250	**FP100**	20 041
FP25 (H)	18 022	**EP25**	18 395
FP50 (H)	18 464	**EP50**	18 512
FP100 (H)	19 349	**EP100**	18 710
S (H)	17 538	**S**	17 985
S25 (H)	17 433	**S25**	17 869
S50 (H)	17 328	**S50**	17 821

Table 7: S50(H)

Plant	Annual generation [GWh]	Installed capacity [MW]	Units built
Coal	1 803	5 850	9
Nuclear	97 627	11 170	5
CCGT	86 241	19 800	18
Hydro	7 904	1 000	2
Diesel	20	1 190	14
PV	6 745	4 350	29
Wind Onshore	3 241	1 600	16
Wind Offshore	17 763	5 200	13
Electrolyzer	50	610	61
Storage	24 307	7 050	705
Fuel cell	15	1 358	13578

Table 8: S25(H)

Plant	Annual generation [GWh]	Installed capacity [MW]	Units built
Coal	1 777	5 850	9
Nuclear	97 631	11 170	5
CCGT	86 234	19 800	18
Hydro	7 904	1 000	2
Diesel	19	1 190	14
PV	6 978	4 500	30
Wind Onshore	3 039	1 500	15
Wind Offshore	17 763	5 200	13
Electrolyzer	49	620	62
Storage	23 704	7 070	707
Fuel cell	14	1 359	13591

Table 9: S(H)

Plant	Annual generation [GWh]	Installed capacity [MW]	Units built
Coal	1 689	5 850	9
Nuclear	97 647	11 170	5
CCGT	86 340	19 800	18
Hydro	7 904	1 000	2
Diesel	17	1 190	14
PV	7 909	5 100	34
Wind Onshore	3 444	1 700	17
Wind Offshore	16 397	4 800	12
Electrolyzer	49	620	62
Storage	33 455	7 710	771
Fuel cell	14	1 478	14775

Table 10: FP100(H)

Plant	Annual generation [GWh]	Installed capacity [MW]	Units built
Coal	1 267	5 850	9
Nuclear	97 574	11 170	5
CCGT	86 922	19 800	18
Hydro	7 904	1 000	2
Diesel	11	1 190	14
PV	15 352	9 900	66
Wind Onshore	12 358	6 100	61
Wind Offshore	0	0	0
Electrolyzer	112	620	62
Storage	71 988	17 540	1754
Fuel cell	32	2 701	27006

Table 11: FP50(H)

Plant	Annual generation [GWh]	Installed capacity [MW]	Units built
Coal	1 267	5 850	9
Nuclear	97 574	11 170	5
CCGT	86 922	19 800	18
Hydro	7 904	1 000	2
Diesel	11	1 190	14
PV	15 352	9 900	66
Wind Onshore	12 358	6 100	61
Wind Offshore	0	0	0
Electrolyzer	112	620	62
Storage	74 812	17 540	1754
Fuel cell	32	2 701	27007

Table 12: FP25(H)

Plant	Annual generation [GWh]	Installed capacity [MW]	Units built
Coal	1 267	5 850	9
Nuclear	97 574	11 170	5
CCGT	86 922	19 800	18
Hydro	7 904	1 000	2
Diesel	11	1 190	14
PV	15 352	9 900	66
Wind Onshore	12 358	6 100	61
Wind Offshore	0	0	0
Electrolyzer	112	620	62
Storage	74 886	17 540	1754
Fuel cell	32	2 701	27006

Table 13: H2050

Plant	Annual generation [GWh]	Installed capacity [MW]	Units built
Coal	1 419	5 200	8
Nuclear	97 567	11 170	5
CCGT	86 708	19 800	18
Hydro	7 904	1 000	2
Diesel	16	1 190	14
PV	12 794	8 250	55
Wind Onshore	14 992	7 400	74
Wind Offshore	0	0	0
Electrolyzer	125	1 470	147
Storage	72 408	22 850	2285
Fuel cell	36	3 348	33480

Table 14: H2030

Plant	Annual generation [GWh]	Installed capacity [MW]	Units built
Coal	1 401	5 200	8
Nuclear	97 566	11 170	5
CCGT	86 693	19 800	18
Hydro	7 904	1 000	2
Diesel	16	1 190	14
PV	13 026	8 400	56
Wind Onshore	14 789	7 300	73
Wind Offshore	0	0	0
Electrolyzer	122	1 470	147
Storage	84 159	22 860	2286
Fuel cell	35	3 348	33482

Table 15: H

Plant	Annual generation [GWh]	Installed capacity [MW]	Units built
Coal	1 334	5 850	9
Nuclear	97 537	11 170	5
CCGT	86 772	19 800	18
Hydro	7 904	1 000	2
Diesel	11	1 190	14
PV	14 422	9 300	62
Wind Onshore	13 371	6 600	66
Wind Offshore	0	0	0
Electrolyzer	58	610	61
Storage	35 519	17 520	1 752
Fuel cell	17	2 700	26 996

Table 16: Baseline

Plant	Annual generation [GWh]	Installed capacity [MW]	Units built
Coal	1 299	9 100	14
Nuclear	96 488	11 170	5
CCGT	91 462	19 800	18
Hydro	4 380	500	1
Diesel	1	935	11
PV	27 681	17 850	119
Wind Onshore	0	0	0
Wind Offshore	0	0	0

Table 17: S50

Plant	Annual generation [GWh]	Installed capacity [MW]	Units built
Coal	2 154	7 800	12
Nuclear	97 634	11 170	5
CCGT	88 426	19 800	18
Hydro	4 380	500	1
Diesel	3	765	9
PV	5 583	3 600	24
Wind Onshore	2 634	1 300	13
Wind Offshore	20 496	6 000	15

Table 18: S25

Plant	Annual generation [GWh]	Installed capacity [MW]	Units built
Coal	1 859	7 800	12
Nuclear	97 700	11 170	5
CCGT	89 409	19 800	18
Hydro	4 380	500	1
Diesel	3	850	10
PV	8 374	5 400	36
Wind Onshore	1 823	900	9
Wind Offshore	17 763	5 200	13

Table 19: S

Plant	Annual generation [GWh]	Installed capacity [MW]	Units built
Coal	1 625	7 800	12
Nuclear	97 676	11 170	5
CCGT	89 165	19 800	18
Hydro	4 380	500	1
Diesel	2	850	10
PV	10 700	6 900	46
Wind Onshore	0	0	0
Wind Offshore	17 763	5 200	13

Table 20: EP100

Plant	Annual generation [GWh]	Installed capacity [MW]	Units built
Coal	1 148	9 100	14
Nuclear	96 256	11 170	5
CCGT	88 119	19 800	18
Hydro	7 904	1 000	2
Diesel	0.8	680	8
PV	27 681	17 850	119
Wind Onshore	203	100	1
Wind Offshore	0	0	0

Table 21: EP50

Plant	Annual generation [GWh]	Installed capacity [MW]	Units built
Coal	1 299	9 100	14
Nuclear	96 488	11 170	5
CCGT	91 462	19 800	18
Hydro	4 380	500	1
Diesel	1	935	11
PV	27 681	17 850	119
Wind Onshore	0	0	0
Wind Offshore	0	0	0

Table 22: EP25

Plant	Annual generation [GWh]	Installed capacity [MW]	Units built
Coal	1 299	9 100	14
Nuclear	96 488	11 170	5
CCGT	91 462	19 800	18
Hydro	4 380	500	1
Diesel	1	935	11
PV	27 681	17 850	119
Wind Onshore	0	0	0
Wind Offshore	0	0	0

Table 23: FP100

Plant	Annual generation [GWh]	Installed capacity [MW]	Units built
Coal	1 108	9 100	14
Nuclear	97 023	11 170	5
CCGT	87 474	19 800	18
Hydro	7 904	1 000	2
Diesel	0.8	680	8
PV	22 331	14 400	96
Wind Onshore	5 470	2 700	27
Wind Offshore	0	0	0

Table 24: FP50

Plant	Annual generation [GWh]	Installed capacity [MW]	Units built
Coal	1 119	9 100	14
Nuclear	96 631	11 170	5
CCGT	87 870	19 800	18
Hydro	7 904	1 000	2
Diesel	0.8	680	8
PV	25 354	16 350	109
Wind Onshore	2 431	1 200	12
Wind Offshore	0	0	0

Table 25: FP25

Plant	Annual generation [GWh]	Installed capacity [MW]	Units built
Coal	1 156	9 100	14
Nuclear	96 269	11 170	5
CCGT	88 300	19 800	18
Hydro	7 904	1 000	2
Diesel	0.8	680	8
PV	27 681	17 850	119
Wind Onshore	0	0	0
Wind Offshore	0	0	0

8.C GAMS Code

```
Sets
i               Units           /Coal, Nuclear, CCGT, Hydro, Geothermal, Diesel/
j               Renewable Units /Wind_Onshore, Wind_Offshore, PV/
k               Hydrogen Units  /Electrolyzer, Storage, FuelCell/
t               Timeperiods     /t1*t8760/
;

Parameters

inv(i)                  Annualized investment costs ($_MW)
invR(j)                 Annualized investment costs of renewables ($_MW)
invH(k)                 Annualized investment costs of hydroge ($_MW)
size(i)                 Capacity size (MW)
sizeR(j)                Renewables capacity size (MW)
sizeH(k)                Hydrogen capacity size (MW)
ra(i)                   Resource available (MW)
raR(j)                  Renewables resource available (MW)
p_min(i)                Minimum production level (MW)
p_minH(k)               Minimum charge_discharge_storage level (MW)
c_e(i)                  Emission costs ($_kgCO2)
c_vom(i)                Variable O&M costs of conventional plants ($_MWh)
c_fom(k)                Fixed O&M costs of hydrogen ($_MW)
q_e(i)                  Efficiency adjusted emission quantity (kgCO2_MWh)
c_fn(i)                 Efficiency adjusted fuel cost ($_MWh)
n(k)                    Hydrogen system efficiency per component (Percentage)

d(t)                    Demand (MW)
wind_Onshore(t)         Wind Onshore profile
wind_Offshore(t)        Wind Offshore profile
pv(t)                   PV profile
hydro(t)                Maximum hourly hydro generation based on monthly data (MWh)

fuelPrice(i)            Fuel price change (Percentage of total)
emisPrice(i)            Emission price change (Percentage of total)
subsidy                 Wind Offshore subsidy ($_MWh)
l0(k)                   Storage level at t=0 (MWh)
HInv(k)                 Hydrogen investment consts change (Percentage of total)

$onEcho > TechnologyData.txt
par=inv         rng=inv!A2:B7       rdim=1
par=invR        rng=invR!A2:B4      rdim=1
par=size        rng=size!A2:B7      rdim=1
par=sizeR       rng=sizeR!A2:B4     rdim=1
par=ra          rng=ra!A2:B7        rdim=1
par=raR         rng=raR!A2:B4       rdim=1
par=p_min       rng=p_min!A2:B7     rdim=1
par=c_e         rng=c_e!A2:B7       rdim=1
par=c_vom       rng=c_vom!A2:B7     rdim=1
par=q_e         rng=q_e!A2:B7       rdim=1
par=c_fn        rng=c_fn!A2:B7      rdim=1
par=fuelPrice   rng=fuelPrice!A2:B7 rdim=1
par=emisPrice   rng=emisPrice!A2:B7 rdim=1
$offEcho
$call gdxxrw.exe TechnologyData.xlsx maxDupeErrors=8760 @TechnologyData.txt
$gdxin TechnologyData.gdx
$load inv invR size sizeR ra raR p_min c_e c_vom q_e c_fn fuelPrice emisPrice
$gdxin
```

```
$onEcho > Demand_Profiles.txt
par=d                   rng=d!A2:B8761                rdim=1
par=wind_Onshore        rng=wind_Onshore!A2:B8761     rdim=1
par=wind_Offshore       rng=wind_Offshore!A2:B8761    rdim=1
par=pv                  rng=pv!A2:B8761               rdim=1
par=hydro               rng=hydro!A2:B8761            rdim=1
$offEcho
$call gdxxrw.exe Demand_Profiles.xlsx maxDupeErrors=8760 @Demand_Profiles.txt
$gdxin Demand_Profiles.gdx
$load d wind_Onshore wind_Offshore pv hydro
$gdxin
;

$onEcho > TechnologyData_Hydrogen.txt
par=invH         rng=invH!A2:B4      rdim=1
par=sizeH        rng=sizeH!A2:B4     rdim=1
par=p_minH       rng=p_minH!A2:B4    rdim=1
par=c_fom        rng=c_fom!A2:B4     rdim=1
par=n            rng=n!A2:B4         rdim=1
par=HInv         rng=HInv!A2:B4      rdim=1
$offEcho
$call gdxxrw.exe TechnologyData_Hydrogen.xlsx maxDupeErrors=8760 @TechnologyData_Hydrogen.txt
$gdxin TechnologyData_Hydrogen.gdx
$load invH sizeH p_minH c_fom n HInv
$gdxin

subsidy=0;
l0('Storage')=0;


Free Variables
Z                Objective function value
;

Integer Variables
p_max(i)         Units built
pR_max(j)        Renewables units built
pH_max(k)        Hydrogen units built

;

Positive Variables
p(i,t)           Production level
l(k,t)           Hydrogen level
;

Equations
obj              Objective function
min(i,t)         Minimum production level constraint
max(i,t)         Maximum production level constraint
max_C(i)         Maximum capacity
min_RG           Minimum renewables generation
max_hydro(i,t)   Maximum hydro generation
dem(t)           Demand constraint

minH(k,t)        Minimum level constraint for hydrogen
maxH(k,t)        Maximum level constraint for hydrogen
```

```
storageH0(k,t)   Hydrogen storage level constraint at t=0
storageH(k,t)    Hydrogen storage level constraint
discharge(k,t)   Fuel cell level constraint
charge(k,t)      Electrolyzer level constraint
;

*********************************************************************************************************
*****************************************Normal Model****************************************************
*********************************************************************************************************
*obj ..                   Z =e= sum((i,t),(c_fn(i)*fuelPrice(i)+(emisPrice(i)*c_e(i)*q_e(i))+c_vom(i
*dem(t) ..                sum(i,p(i,t)) =e= d(t) - pR_max('Wind_Onshore')*sizeR('Wind_Onshore')*wind_

min(i,t) ..              p(i,t) =g= p_min(i);
max(i,t) ..              p(i,t) =l= p_max(i)*size(i);
max_C(i) ..              p_max(i) =l= (ra(i))/size(i);
min_RG ..                sum(t, pR_max('Wind_Onshore')*sizeR('Wind_Onshore')*wind_Onshore(t) + pR_ma
max_hydro('Hydro',t) ..  p('Hydro',t) =l= hydro(t);

*********************************************************************************************************
*************************************Hydrogen extension**************************************************
*********************************************************************************************************

obj ..                   Z =e= sum((i,t),(c_fn(i)*fuelPrice(i)+(emisPrice(i)*c_e(i)*q_e(i))+c_vom(i)

dem(t) ..                sum(i,p(i,t)) + l('FuelCell',t) - l('Electrolyzer',t) =e= d(t) - pR_max('Wi

minH(k,t) ..             l(k,t) =g= p_minH(k);
maxH(k,t) ..             l(k,t) =l= pH_max(k)*sizeH(k);

*storageH0('Storage',t)$(ord(t)=1) ..     l('Storage',t) =e= l0('Storage')+ l('Electrolyzer',t) - l(
*storageH('Storage',t)$(ord(t)>1) ..      l('Storage',t) =e= l('Storage',t-1)+ l('Electrolyzer',t) -
*discharge('FuelCell',t) ..               l('FuelCell',t) =l= l('Storage',t);
*charge('Electrolyzer',t) ..              l('Electrolyzer',t) =l= pR_max('Wind_Onshore')*sizeR('Wind_


storageH0('Storage',t)$(ord(t)=1) ..     l('Storage',t) =e= l0('Storage')+ l('Electrolyzer',t)*n('El
storageH('Storage',t)$(ord(t)>1) ..      l('Storage',t) =e= l('Storage',t-1)+ l('Electrolyzer',t)*n(
discharge('FuelCell',t) ..               l('FuelCell',t) =l= l('Storage',t)*n('FuelCell');
charge('Electrolyzer',t) ..              l('Electrolyzer',t) =l= pR_max('Wind_Onshore')*sizeR('Wind_

option intVarUp = 0;

Model Carolina /all/ ;
Carolina.OptCR=0.001;
*$onecho > cplex.opt
*epmrk = 0.6
*$offecho
*Carolina.OptFile=1;
Solve Carolina using MIP minimizing Z ;

file results / results.txt /;
*Specifiying that we want a comma separated file:
results.pc = 5;
put results;
put "Time period", "Coal", "Nuclear", "CCGT", "Hydro", "Geothermal", "Diesel"/;
loop(t,
put t.tl,
        loop(i,
```

```
                put p.l(i,t);
        );
put /;
);
putclose;

file resultsH / resultsH.txt /;
*Specifiying that we want a comma separated file:
resultsH.pc = 5;
put resultsH;
put "Time period", "Electrolyzer", "Storage", "FuelCell"/;
loop(t,
put t.tl,
        loop(k,
                put l.l(k,t);
        );
put /;
);
putclose;

execute_unload "results.gdx" z.L p_max.L pR_max.L pH_max.L dem.M

execute 'gdxxrw.exe results.gdx o=results.xlsx var=z.L rng=System!'
execute 'gdxxrw.exe results.gdx o=results.xlsx var=p_max.L rng=Units! rDim=1'
execute 'gdxxrw.exe results.gdx o=results.xlsx var=pR_max.L rng=RenewableUnits! rDim=1'
execute 'gdxxrw.exe results.gdx o=results.xlsx var=pH_max.L rng=HydrogenUnits! rDim=1'
execute 'gdxxrw.exe results.gdx o=results.xlsx equ=dem.M rng=Price! rDim=1'
```

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