Avoidance of partial load operation at coal-fired power plants by storing nuclear power through Power to Gas

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Abstract

The need of fast regulation of electricity production leads to a number of inconveniences occurred to the electric generation system and the electric market, especially to the nuclear power. A new concept to control nuclear power production is posed in order to allow the regulation of the electricity sent to the grid. This concept proposes the joint operation of a nuclear power plant, a coal power plant with postcombustion capture and a methanation plant. The cost effectiveness of this technology and its capability to reduce the CO_2 emissions -consumed in the methanation process- are assessed through the design and economic and environmental analysis of a hybrid facility. Mainly due to the increase of the operating hours of the coal-fired power plant, the environmental feasibility of the initial proposal seems to be limited. However, given that benefits are expected in the medium and long-term (2020-2030) for the Power to Gas facility, a future alternative use is proposed. The target of this new alternative configuration will be the storage of CO_2 together with the storage of renewable energy.

Keywords

Power-to-Gas, Oxy-fuel combustion, Methanation, Photovoltaic, Renewable Energy, Integration,

1. Introduction

The electricity market has been liberalized in all EU member countries, except Bulgaria and Malta. In most countries, the number of years since the electricity market liberalization is between 5 and 10. Although in the United Kingdom and Norway it has been in place for more than 20 years. The last EU country to liberalize the market was Cyprus.

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Under these liberalized markets, electricity prices are set on a daily basis for the twenty-four hours of the following day. This is referred as the daily market. The price and volume of energy over a specific hour are determined by the point at which the supply and demand curves meet, according to the marginal pricing model adopted by the most of EU countries besides Iberian market (Spain and Portugal). The purchase and sale bids of the buying and selling agents are accepted according to their economic merit order [1]. The results of the daily market, determined by the free trade between buying and selling agents, are the most efficient solution from an economic perspective. Nevertheless, given the nature of electricity, this process also needs to be feasible in physical terms. Accordingly, obtained results are validated by the System Operator from the standpoint of technical viability. Daily market results may be slightly altered (affecting around 4-5% of the energy) in response to an analysis of the technical constrains conducted by the System Operator. After these modifications the definitive viable daily program is defined [2].

Considering the operation of the power systems, higher penetration of renewable energy sources (RES) in the energy mix may affect the technical and economic operation of the power system. From a technical perspective, the system could lack of flexibility since intermittent RES require flexibility but coal-fired and nuclear power plants are relatively inflexible [3]. The particular technical conditions of nuclear power plants – generally included in the electric pool as selling agents - do not allow a flexible operation able to follow the variable demand but obey a continuous operation at base load [4]. Besides, partial load operation strongly reduces the efficiency of coal-fired power plants [5]. From an economic point of view, higher RES penetration may reduce the profitability of nuclear plants and other conventional power plants by decreasing their capacity factor and lowering wholesale electricity prices - lower electricity prices through the merit order effect [6]. Given the rigid operation of nuclear power plants, their electrical production bid is zero to ensure that their production will be included in the daily energy mix. The rest of participants establish the final MWh price and adapt their production to the fluctuation of energy consumption [4].

Bertsch et al. studied a future European energy mix with an 80% RES penetration by 2050 and concluded that flexibility will largely be provided by gas turbines, and that operation of nuclear power and generators with CCS will break even [7]. Brouwer et al. studied the operational flexibility and economics of power plants in future low-carbon power systems [8]. Bertsch et al. and Brouwer et al. reported that the capacity factors of

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base-load and mid-load plants decrease over time when RES penetration increases. Bertsch reports a larger average decrease in capacity factor of coal-fired plants between 2030 and 2050 (36%, compared to 8% across all scenarios obtained by Brouwer et al.). Moreover, Bertsch concludes that the profitability of base-load plants is adequate, of mid-merit is break-even, and of peak-load is not sufficient [7]. However, Brouwer et al. report lower revenues for mid-merit and peak-load capacity, potentially because they do not account for reserve revenues, and because they have a higher base-load capacity, shifting the merit order position of mid-merit power plants [8]. These studies do not consider the possibility of introducing long-term massive storage of electricity as a regulation tool to avoid partial load operation for coal-fired power plants and to increase profitability of nuclear production. It makes necessary to introduce new concepts which make economically feasible these power plants. This study aims to fill this research gap by providing a consistent concept which allows for the regulation of the amount of nuclear energy offered in the daily market. From the producer point of view, this would permit to decide those most adequate selling hours which imply an optimization of the economic incomes. From the consumer point of view, long-term storage of the electricity provides a more stable price of electricity, a reduction of prices and reduces the uncertainty of the market. Besides, environmental load associated to carbon emissions of the electricity production will be reduced.

2. Electricity dispatch of nuclear and coal power

Nuclear power typically operates at nominal load throughout the year with occasional planned and unplanned stops, achieving equivalent availability factors above the 85% [9]. Its operation flexibility is clearly limited by cold and hot start-ups, which may last more than 24 hours [10]. Even in France, one of the most nuclearized countries in the world, shut-downs related to low demand of electricity are limited to one per reactor and year on average [11]. Besides, fuel replacement only takes place every 12-24 months [12], and partial load operations are not recommended during the reactor lifetime to minimize the usage of neutron poisons in the core [11].

As nuclear power operates steadily and renewable power sources are preferred to fossil sources in the daily market, coal and natural gas technologies are compelled to fulfil demand under a sharp variable profile derived from the high penetration of solar and wind power. Gas-fired combined cycle plants can be considered to be less penalized than coal-fired power plants in this context thanks to their higher efficiency, lower

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emissions and better performance under partial loads [10]. Then, this paper focuses the study on the most critical variable operation of coal-fired power plants.

Partial load operation in coal-fired power plants implies a reduction in overall efficiency. This reduction of efficiency is derived from worse radiative and convective exchanges inside the boiler which will also produce an increment in specific emissions due to variations in the temperature inside the furnace [13]. These two disadvantages also imply:

(i) *An increment in the operating cost of the facility*: The reduction of efficiency leads to an increase of the consumption of fuel per unit of produced energy (i.e., of the specific operating cost of the facility).

(ii) *A handicap to fulfil the legislative regulation*: The increment of specific emissions makes difficult to operate the power plant according to the demanding restrictions of the European Directive 2010/75/UE [14]. Currently, power plants are complying with the legislation since Transitional National Plans allow wider specific emissions thresholds until June 2020.

(iii) *A reduction in the facility life-time*: The high number of hot- and cold start-ups related to partial load operation remarkably reduces the lifetime of the facilities. Some studies estimates 200 cold start-ups and 5,000 hot start-ups on average for subcritical coal-fired power plants [10].

2.1. Power to Gas as managing system to avoid penalties of partial load operation

As stated, despite nuclear power does not directly emits CO_2, its base load operation collaterally worsen the environmental performance of coal-fired power plants. However, if nuclear power plants operation was flexible and regularly operated at partial load, the drastic reduction in their availability factors could compromise their profitability. A potential solution would be to find an alternative electricity storage solution for the nuclear electricity production to limit the fluctuant regime for coal-fired power plants operation [11]. The partial load operation in coal-fired power plants is avoided by displacing part of the electricity from nuclear power plants. This mode of operation should be considered as a short- and mid-term solution which reduces specific carbon emissions of the national energy mix, until renewable sources are able to properly dispatch their production and carbon capture methods are widely deployed.

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The study presents the utilization of Power to Gas (PtG) technology to store electricity in the form of synthetic methane, which can be introduced in the gas network [15]. The final aim is to establish a connection between electric and gas networks, through which the displaced electricity can be stored and later used to satisfy end-user thermal or electrical demand (industry, households, buildings or transport). The process provides the displaced electricity to electrolyzers where water is dissociated in hydrogen and oxygen. Then, a methanation reaction stage combines the produced hydrogen with carbon dioxide to produce the synthetic methane. Moreover, carbon dioxide would be captured from flue gas stream of the coal-fired power plants to reduce their net emission (Figure 1).

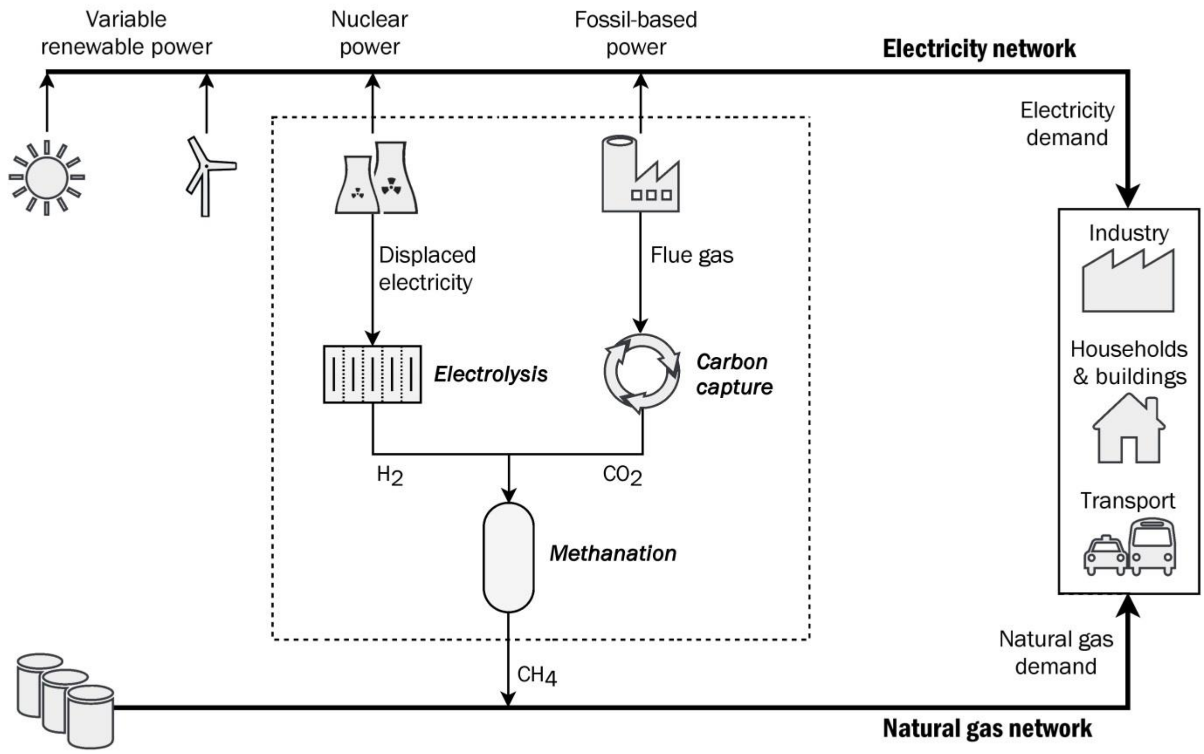

Figure 1. Schematic diagram of the nuclear power displacement through Power to Gas

The application of the proposed solution is assessed for a system consisting of a nuclear power plant, a coal-fired power plant with amine carbon capture, and a Power to Gas plant (dashed line in Figure 1). The selected sizes of the power plants correspond to average current values (1,060 MW for nuclear power [16], $W_{nucl,0}$, and 350 MW for coal-fired power [17], $W_{coal,0}$). Regarding methanation, current facilities' sizes are limited to

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a maximum of 6 MW [18]. However, the proposed system will require a higher installed power since current capacities would only store about the 0.6% of the electricity from the proposed nuclear power plant.

In practice, the aim of this study for the management of the coal-fired power plant is to avoid partial load whenever the plant is operative, not to operate the power plant when it was usually stopped (i.e., when the operating load must be reduced below the 40% of the nominal load). Hence, the Power to Gas plant is sized to be able to store a 60% of the power capacity of the coal-fired power plant, i.e., 210 MW. The coal-fired power plant will operate during the same periods of the year, but always at 100% load through the regulation based on PtG.

3. Methodology

The global objective of the paper is to assess the environmental and techno-economic feasibility of the proposed system as an alternative for energy storage in the electricity mix. The characterization of the coal-fired power plant under partial load operation provides the instantaneous amount of electricity to be displaced, and allows the comparison of partial load performance with the operation at full load. Then, the energy penalty of the amine carbon capture plant is calculated through simulation, while the model of the methanation plant provides the energy efficiency of the energy storage (i.e., the available methane for selling).

3.1. Partial load operation in coal-fired power plants

The characterization of the coal-fired power plant includes three key aspects: (i) the operating hours, (ii) the energy efficiency, and (iii) the carbon dioxide emissions.

3.1.1. Operating hours

As an initial assumption, the coal-fired power plant operates 3,500 equivalent hours, h_{eq}, along a year [19]. Considering these equivalent hours, the total electricity produced by the coal-fired power plant of this case study amounts to 1,228.5 GWh. This annual amount of electricity, E_{coal}, is actually generated during a higher number of hours in which the plant operates at different loads (Equation 1). The actual number of operation hours extends to 4,756.5 hours with load varying from 40-100% (Table 1).

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$$E_{coal} = h_{eq} \cdot W_{coal,0} = \int_{0.4 \cdot W_{coal,0}}^{W_{coal,0}} h(W_{coal}) \cdot dW_{coal} \quad (1)$$

Besides, the amount of electricity that will have to be displaced from nuclear production to ensure the nominal operation of the coal-fired plant is given by Equation 2, which depends on the instantaneous operating capacity, W_{coal}, through h and E_{coal}.

$$E_{disp}(W_{coal}) = h(W_{coal}) \cdot W_{coal,0} - E_{coal}(W_{coal}) \quad (2)$$

Table 1. Electricity production and displaced electricity at different operating load intervals

Operating load W_{coal} [%]	Operating load W_{coal} [MW]	Operating hours h [h]	Electricity from coal E_{coal} [GWh]	Electricity to be displaced E_{disp} [GWh]
[40 – 45]	140 – 157	170.3	25.4	34.4
(45 – 50]	158 – 175	228.2	38.1	42.0
(50 – 55]	176 – 193	293.7	54.3	48.8
(55 – 60]	194 – 210	340.4	68.8	50.6
(60 – 65]	211 – 228	424.2	93.2	55.7
(65 – 70]	229 – 245	451.9	107.2	51.5
(70 – 75]	246 – 263	516.5	131.5	49.8
(75 – 80]	264 – 280	503.9	137.1	39.8
(80 – 85]	281 – 298	526.7	152.5	32.4
(85 – 90]	299 – 315	469.4	144.1	20.7
(90 – 95]	316 – 333	447.8	145.2	12.0
(95 – 100]	334 – 351	383.4	131.2	3.4
Total range:	**140 - 351**	**4,756.5**	**1,228.5**	**441.0**

As a reference, a typical electrical market has been used to set the electricity prices. In this case, the Spanish electrical market scenario where the cost of the most expensive 4,757 hours in the daily electricity market ranges from 45.9 €/MWh to 120.0 €/MWh [20]. This means that the coal-fired power plant do not operate when revenues are below 45.9 €/MWh. This threshold is taken as the operating cost of the facility.

3.1.2. Efficiency

According to Linneberg et al. [21], the efficiency of coal-fired power plants may decrease 2.8 points from full to 40% partial load. Since average net efficiency of this technology is near 36% [22], an efficiency curve in the range 33.1% - 35.9% is modelled in the study for partial loads starting from 40%. The trend presented by Linneberg [21] is also used in this study, proportionally scaling-down the values in order to fit the selected

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range of efficiencies. Besides, the curve is adjusted to a quadratic polynomial (Equation 3) as recommended in literature when the boiler efficiency is only a function of the boiler part-load [23].

$$\eta_{coal} = 0.28 + 4.644 \cdot 10^{-4} \cdot W_{coal} - 6.818 \cdot 10^{-7} \cdot W_{coal}{}^{2} \tag{3}$$

The loss of efficiency in coal power plants when they operate at part-load is the energy penalization that the present study intends to avoid by displacing electricity from nuclear power by using the Power to Gas energy storage.

3.1.3. Carbon dioxide emissions

The carbon dioxide emissions of the coal-fired power plant are calculated through the mole balance of the overall reaction of combustion (stoichiometric coefficients are given in kmol/kg$_{\text{fuel}}$):

$$\overset{\text{Coal}}{(\bar{\nu}_{\text{C}}\ \text{C} + \bar{\nu}_{\text{H}}\ \text{H} + \bar{\nu}_{\text{N}}\ \text{N} + \bar{\nu}_{\text{O}}\ \text{O} + \bar{\nu}_{\text{M}}\ \text{M} + \bar{\nu}_{\text{Z}}\ \text{Z})} + \overset{\text{Air}}{\bar{\nu}_{\text{Air}}\ (\text{O}_2 + 3.76\ \text{N}_2)} \rightarrow$$

$$\rightarrow \overset{\text{Flue gas}}{(\bar{\mu}_{\text{CO2}}\ \text{CO}_2 + \bar{\mu}_{\text{CO}}\ \text{CO} + \bar{\mu}_{\text{O2}}\ \text{O}_2 + \bar{\mu}_{\text{N2}}\ \text{N}_2 + \bar{\mu}_{\text{H2O}}\ \text{H}_2\text{O})} + \overset{\text{Residues}}{(\bar{\mu}_{\text{Z}}\ \text{Z} + \bar{\mu}_{\text{C}}\ \text{C})}$$

The stoichiometric coefficients denoted with $\bar{\nu}$ are related to the moles of reagents per unit of kg of fuel (those referring to coal are known values thanks to the ultimate analysis of the fuel, Table 2). The products per unit of kg of fuel are denoted with $\bar{\mu}$, which includes the generated species in the flue gas and the resulting residues (ashes plus unburned carbon).

Table 2. Ultimate analysis of the selected coal for the study, and stoichiometric values.

	Carbon (C)	Hydrogen (H)	Nitrogen (N)	Oxygen (O)	Moisture (M)	Ash (Z)
Mass fraction*, w_i [kg/kg$_{\text{fuel}}$]	0.661	0.036	0.016	0.071	0.086	0.124
Stoichiometric coefficient	$\bar{\nu}_{\text{C}}$	$\bar{\nu}_{\text{H}}$	$\bar{\nu}_{\text{N}}$	$\bar{\nu}_{\text{O}}$	$\bar{\nu}_{\text{M}}$	$\bar{\nu}_{\text{Z}}$
Stoichiometric coefficient value [kmol/kg$_{\text{fuel}}$]	0.055030	0.035720	0.001142	0.004438	0.004774	-

*The remaining fraction corresponds to Sulphur, which is neglected in the combustion reaction.

To obtain the amount of CO_2 that is emitted per kilogram of fuel (i.e., the stoichiometric coefficient $\bar{\mu}_{\text{CO2}}$), a system of 7 equations must be solved (unknown quantities: $\bar{\nu}_{\text{Air}}$, $\bar{\mu}_{\text{CO2}}$, $\bar{\mu}_{\text{CO}}$, $\bar{\mu}_{\text{O2}}$, $\bar{\mu}_{\text{N2}}$, $\bar{\mu}_{\text{H2O}}$, $\bar{\mu}_{\text{C}}$). The first

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four equations are the mole balances corresponding to carbon, hydrogen, nitrogen and oxygen (Equations 4 to 7).

$$\bar{\nu}_{\mathrm{C}} = \bar{\mu}_{\mathrm{CO2}} + \bar{\mu}_{\mathrm{CO}} + \bar{\mu}_{\mathrm{C}} \qquad \text{(Carbon balance)} \tag{4}$$

$$\bar{\nu}_{\mathrm{H}} + 2\,\bar{\nu}_{\mathrm{M}} = 2\,\bar{\mu}_{\mathrm{H2O}} \qquad \text{(Hydrogen balance)} \tag{5}$$

$$\bar{\nu}_{\mathrm{N}} + 2\,\bar{\nu}_{\mathrm{Air}} \cdot 3.76 = 2\,\bar{\mu}_{\mathrm{N2}} \qquad \text{(Nitrogen balance)} \tag{6}$$

$$\bar{\nu}_{\mathrm{O}} + \bar{\nu}_{\mathrm{M}} + 2\,\bar{\nu}_{\mathrm{Air}} = 2\,\bar{\mu}_{\mathrm{CO2}} + \bar{\mu}_{\mathrm{CO}} + 2\,\bar{\mu}_{\mathrm{O2}} + \bar{\mu}_{\mathrm{H2O}} \qquad \text{(Oxygen balance)} \tag{7}$$

The other three required equations come from operating parameters that are usually measured in coal-fired power plants: (i) mole fraction of O_2 in flue gas in dry basis (Equation 8), (ii) mole fraction of CO in flue gas in dry basis (Equation 9), and (iii) mass fraction of unburned carbon in residues (Equation 10, in which w' stands for mass fractions with respect to residues [kg/kg$_{\mathrm{residues}}$], w for mass fractions with respect to coal fuel [kg/kg$_{\mathrm{fuel}}$], and M for molar mass).

$$x'_{O2} = \frac{\bar{\mu}_{\mathrm{O2}}}{\bar{\mu}_{\mathrm{CO2}}+\bar{\mu}_{\mathrm{CO}}+2\,\bar{\mu}_{\mathrm{O2}}+\bar{\mu}_{\mathrm{N2}}} \tag{8}$$

$$x'_{CO} = \frac{\bar{\mu}_{\mathrm{CO}}}{\bar{\mu}_{\mathrm{CO2}}+\bar{\mu}_{\mathrm{CO}}+2\,\bar{\mu}_{\mathrm{O2}}+\bar{\mu}_{\mathrm{N2}}} \tag{9}$$

$$w'_{C} = \frac{\bar{\mu}_{\mathrm{C}} \cdot \mathrm{M_C}}{w_R} = \frac{\bar{\mu}_{\mathrm{C}} \cdot \mathrm{M_C}}{w_z/(1-w'_C)} \tag{10}$$

The following operating conditions are assumed in order to solve the system of equations: $x'_{O2} = 0.04$, $x'_{CO} = 0.0001$ and $w'_C = 0.01$. The specific carbon dioxide emissions of the coal-fired power plant, t_{CO2}, can be calculated through Equation 11 (lower heating value of the coal of Table 2 is 25,416 kJ/kg).

$$t_{CO2}\left[\frac{\mathrm{t}}{\mathrm{MWh_e}}\right] = \frac{\bar{\mu}_{\mathrm{CO2}}\left[\frac{\mathrm{kmol}}{\mathrm{kg_{fuel}}}\right] \cdot \mathrm{M_{CO2}}\left[\frac{\mathrm{kg}}{\mathrm{kmol}}\right]}{\eta_{coal}\left[\frac{\mathrm{MWh_e}}{\mathrm{MWh}}\right] \cdot LHV_{coal}\left[\frac{\mathrm{MWh}}{\mathrm{kg_{fuel}}}\right] \cdot 1{,}000\left[\frac{\mathrm{kg}}{\mathrm{t}}\right]} \tag{11}$$

The carbon dioxide emissions depend on the operating capacity, W_{coal}, through the net efficiency, η_{coal} (Equation 3). The lower operating load W_{coal}, the lower efficiency η_{coal}, and the higher specific CO_2 emissions t_{CO2}. In order to avoid this increment in specific emissions that prevents from accomplishing the

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European Directives, the present study assesses the displacement to the gas network of part of the electricity from nuclear power (instead of load reduction in coal-fired power plants) by using the Power to Gas energy storage technology.

3.2. Amine carbon capture in coal-fired power plants

The carbon dioxide consumed in the methanation reaction is assumed to be captured from the coal-fired power plant (Figure 1) by amine scrubbing. The associated energy penalty must be quantified to properly compare the operation at 100% load with a small carbon capture plant (subsection 3.2) versus the conventional operation at variable load without carbon capture (subsection 3.1).

The amine carbon capture plant is modelled in Equation Engineering Solver (EES) software following the scheme of Figure 2. The fraction of flue gas to be treated varies depending on the amount of electricity stored in the PtG plant. This flue gas flow is introduced into the plant (0) and compressed to 1.5 bar (1). Then, gases are cooled down to 45 ºC (2) before entering the absorber (AC) to favour the absorption reaction, which is exothermic (1.92 MJ/kg_{CO2}) [24,25]. Reaction takes place between the counter-flowing solvent (mono-ethanolamine in water at 30% mass fraction) and CO_2. The vent gas leaves the absorber at the top (3) and the solution of CO_2 and aqueous MEA (rich amine solution) leaves the column at the bottom (4). The latter is pre-heated from 57 ºC to 95 ºC (5) prior the stripper (DC). The solvent and CO_2 will be separated by increasing the temperature up to 110 ºC in the stripper. The required thermal energy is transferred by heating a small recirculation from the outlet of the stripper (7), which is reintroduced as steam to rise throughout the column (8). Thus, the rich amine solution is regenerated by separation of the aqueous MEA (6) and the carbon dioxide (15). The CO_2 outlet is typically at 90%vol. with 10%vol. of steam, which must be condensed and entering again in the stripper (16), to achieve pure CO_2 (17). The regenerated aqueous MEA is directed to the absorber to close the cycle (11) after cooling it to 50 ºC with exchanger Ex2.

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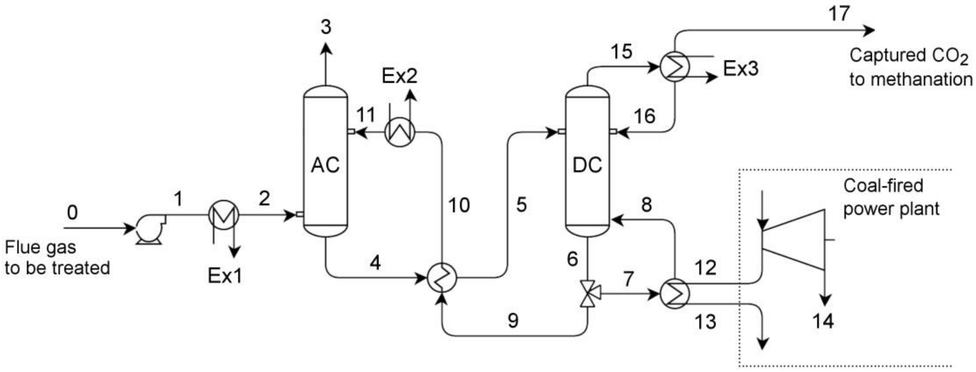

Figure 2. Scheme of the amine carbon capture plant

The amount of carbon dioxide to be treated will depend on the produced amount of hydrogen (i.e., on the power consumed by the electrolyser, W_{el}, and its efficiency, η_{el}, which is assumed 75%) following Equation 12, according to the stoichiometry of methanation reaction (Equation 22). The total flow at point 0, $\dot{m}_{[0]}$, will be a small fraction of the whole flue gas.

$$\dot{m}_{CO2[0]} = \frac{1}{4} \cdot \frac{\mathrm{M_{CO2}}}{\mathrm{M_{H2}}} \cdot \frac{\eta_{el} \cdot W_{el}}{LHV_{H2} \cdot 3{,}600} \quad (12)$$

The solvent circulating through the absorber is a mixture of 30% mono-ethanolamine (MEA) and 70% water, in mass basis. Besides, the cyclic sorption capacity of MEA, η_{MEA}, is assumed to be 0.144 $\mathrm{kg_{CO2}/kg_{MEA}}$ [26], and the required mass flow at point 11 is given by Equation 13.

$$\dot{m}_{[11]} = \frac{\dot{m}_{CO2[0]}}{\eta_{\mathrm{MEA}}} \cdot \frac{1}{0.3} \quad (13)$$

This mass flow, together with the captured CO_2, has to be heated later in the stripper to desorb the CO_2. A small recirculation from the outlet of the stripper (7) is indirectly heated with steam from the power cycle of the coal-fired power plant (12). The steam is taken prior the low-pressure turbine, which is at 160 ºC and 3 bar (12), and then is returned to the deaerator as saturated liquid at the same pressure (13). The amount of heat that has to be extracted at point 12 (Equation 14) can be calculated through an energy balance accounting for the thermal energy required to desorb the CO_2, Q_{des}, in order to heat the aqueous MEA solution from points (5) to (6), and to heat the recirculated water from (16) to (15). It is assumed that the thermal energy required to desorb the CO_2 is 1.92 MJ per kilogram of carbon dioxide [24,25], and that the specific heat capacity of MEA

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is constant at 182 kJ/kmol·K [27] with a molar mass of 61.09 kg/kmol [28]. Moreover, the mass of water at point (15) is calculated assuming that it represents a 10%vol. of the outlet.

$$\dot{m}_{[12]}\left(\bar{h}_{[12]}-\bar{h}_{[13]}\right)=Q_{des}+\dot{m}_{H2O[5]}\left(\bar{h}_{H2O[6]}-\bar{h}_{H2O[5]}\right)+\dot{m}_{\mathrm{MEA}[5]}Cp_{\mathrm{MEA}}\left(T_{[6]}-T_{[5]}\right)+\dot{m}_{[16]}\left(\bar{h}_{H2O[15]}-\bar{h}_{[16]}\right) \quad (14)$$

Similarly, the mass flow of solution that must circulate through points (7) and (8) can be calculated through the energy balance of Equation 15. In this equation the thermal energy extracted from the steam cycle is known from Equation 14, the temperature at point (8) is fixed to 120 ºC to avoid degradation of the amines, and $\dot{m}_{\mathrm{MEA}[8]}=\dot{m}_{H2O[8]}\cdot 0.3/0.7$.

$$\dot{m}_{[12]}\left(\bar{h}_{[12]}-\bar{h}_{[13]}\right)=\dot{m}_{H2O[8]}\left(\bar{h}_{H2O[8]}-\bar{h}_{H2O[7]}\right)+\dot{m}_{\mathrm{MEA}[8]}Cp_{\mathrm{MEA}}\left(T_{[8]}-T_{[7]}\right) \quad (15)$$

The equivalent power that the steam extracted from the power cycle would have generated, W_{loss}, is given by Equation 16, in which turbine is considered isentropic ($\eta_{s,t}=0.9$) with the inlet at 160 ºC and 3 bar, and the outlet at 0.05 bar after passing through the low-pressure turbine (point (14)).

$$W_{loss}=\dot{m}_{[12]}\left(\bar{h}_{[12]}-\bar{h}_{[14]}\right) \quad (16)$$

In addition, the power consumed by the compressor at point (1), $W_{c[1]}$, has to be accounted (Equation 17). The isentropic efficiency of the compressor is assumed 0.9.

$$W_{c[1]}=\dot{m}_{[1]}\left(\bar{h}_{[1]}-\bar{h}_{[0]}\right) \quad (17)$$

The efficiency of the coal-fired power plant will vary depending on W_{loss} and $W_{c[1]}$ (Equation 18). The more energy is displaced from nuclear power plant; the more hydrogen is produced in electrolysis, the more CO_2 has to be captured to perform methanation, and the greater W_{loss} and $W_{c[1]}$.

$$\eta_{coal,disp}=\eta_{coal,0}\cdot\left(1-\frac{W_{loss}+W_{c[1]}}{W_{coal,0}}\right) \quad (18)$$

The specific carbon dioxide emissions of the coal-fired power plant when the amine plant is under operation (i.e., when electricity from nuclear power plant is displaced), $t_{CO2,disp}$, can be calculated by Equation 19. This

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accounts for the avoided emissions, $\dot{m}_{[17]}$, and for the variation in the power plant efficiency due the carbon capture penalization, $\eta_{coal,disp}$.

$$t_{CO2,disp}\left[\frac{\mathrm{t}}{\mathrm{MWh_e}}\right]=\frac{\bar{\mu}_{\mathrm{CO2}}\left[\frac{\mathrm{kmol}}{\mathrm{kg_{fuel}}}\right]\cdot \mathrm{M_{CO2}}\left[\frac{\mathrm{kg}}{\mathrm{kmol}}\right]}{\eta_{coal,disp}\left[\frac{\mathrm{MWh_e}}{\mathrm{MWh}}\right]\cdot LHV_{coal}\left[\frac{\mathrm{MWh}}{\mathrm{kg_{fuel}}}\right]\cdot 1{,}000\left[\frac{\mathrm{kg}}{\mathrm{t}}\right]}-\frac{\dot{m}_{[17]}\left[\frac{\mathrm{kg}}{\mathrm{s}}\right]\cdot 3{,}600\left[\frac{\mathrm{s}}{\mathrm{h}}\right]}{W_{coal,0}[\mathrm{MW_e}]\cdot 1{,}000\left[\frac{\mathrm{kg}}{\mathrm{t}}\right]} \tag{19}$$

When the coal-fired power plant operates at nominal load and there is no electricity displaced from the nuclear power plant, Equation 19 becomes Equation 11.

3.3. Power to Gas plant

The overall efficiency of the Power to Gas plant must be computed in order to quantify how much synthetic natural gas is produced (i.e., the available amount for selling) from the electricity displaced from the nuclear power plant. The methanation plant is modelled in EES software following the configuration of Figure 3. The scheme is based on TREMP™ technology (which is described in [29]) and other previous lay-outs from the authors [30–32]. This comprises three adiabatic methanators operating at 25 bar with recycling loops in the first and third ones, and an intermediate water condensation after the second methanator. This configuration allows reaching methane contents above 95 vol.% under the proper operating conditions.

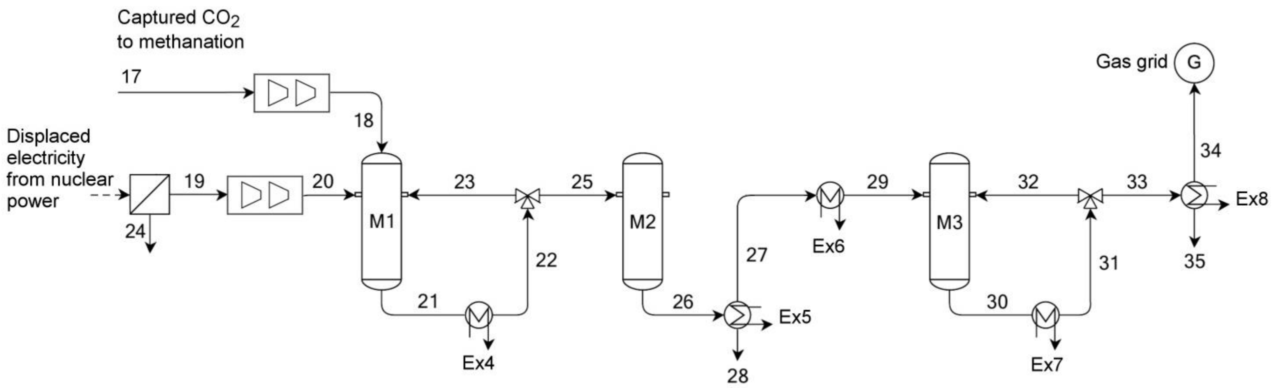

Figure 3. Scheme of the Power to Gas plant

First, hydrogen (19) and oxygen (24) are produced through electrolysis by consuming the displaced electricity. Then, the hydrogen (20) and the carbon dioxide (18) are pressurized to 25 bar by two multi-stage compressors, which also increase the temperature of the gasses thus avoiding pre-heating prior the first methanator. The outlet gas (21) is cooled down to 300 ºC (22) and the 78% of the flow is recirculated (23) to

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control the temperature increase. After the second reactor (26) the water content normally exceeds the 60%, which inhibits the reaction. Therefore, approximately the 90% of the water is condensed (28) and the resulting gas must be pre-heated again to 300 ºC (29) before entering the third methanator. Another recirculation is placed in the third reactor, accounting for the 78% of the outlet (32). The water content of the remaining gas is condensed (35), and the dry synthetic gas is injected in the gas grid (34).

The methanation of CO_2 that takes place inside the reactors (Equation 20) can actually be decomposed as the combination of the reverse water-gas shift reaction (Equation 21) and a subsequent CO methanation (Equation 22) [33].

$$\mathrm{CO_2 + 4H_2 \leftrightarrow CH_4 + 2H_2O} \qquad \Delta \mathrm{H_{298K}} = -165.0\ \mathrm{kJ/mol} \tag{20}$$

$$\mathrm{CO_2 + H_2 \leftrightarrow CO + H_2O} \qquad \Delta \mathrm{H_{298K}} = +41.2\ \mathrm{kJ/mol} \tag{21}$$

$$\mathrm{CO + 3H_2 \leftrightarrow CH_4 + H_2O} \qquad \Delta \mathrm{H_{298K}} = -206.1\ \mathrm{kJ/mol} \tag{22}$$

The products of the CO_2 methanation are calculated through the mole balance of the overall reaction (stoichiometric coefficients are given in kmol):

$$\nu_{CO2}\mathrm{CO_2} + \nu_{H2}\mathrm{H_2} + \nu_{CH4}\mathrm{CH_4} + \nu_{H2O}\mathrm{H_2O} + \nu_{CO}\mathrm{CO} \leftrightarrow \mu_{CO2}\mathrm{CO_2} + \mu_{H2}\mathrm{H_2} + \mu_{CH4}\mathrm{CH_4} + \mu_{H2O}\mathrm{H_2O} + \mu_{CO}\mathrm{CO}$$

where ν_i are the initial moles of reagent i, and μ_i the final moles of product i. The latter are the five unknown variables that give the gas composition after the reaction. These are computed through the mole balances of carbon, hydrogen and oxygen (Equations 23 – 25) and through the equilibrium constants of the involved reactions (Equations 26 – 27).

$$\nu_{CO2} + \nu_{CH4} + \nu_{CO} = \mu_{CO2} + \mu_{CH4} + \mu_{CO} \qquad \text{(Carbon balance)} \tag{23}$$

$$\nu_{H2} + 2 \cdot \nu_{CH4} + \nu_{H2O} = \mu_{H2} + 2 \cdot \mu_{CH4} + \mu_{H2O} \qquad \text{(Hydrogen balance)} \tag{24}$$

$$\nu_{CO2} + \frac{1}{2}\nu_{H2O} + \frac{1}{2}\nu_{CO} = \mu_{CO2} + \frac{1}{2}\mu_{H2O} + \frac{1}{2}\mu_{CO} \qquad \text{(Oxygen balance)} \tag{25}$$

$$Kp_{RWGS} = \frac{x_{CO} \cdot x_{H2O}}{x_{CO2} \cdot x_{H2}} = \frac{\mu_{CO} \cdot \mu_{H2O}}{\mu_{CO2} \cdot \mu_{H2}} \qquad \text{(Reverse water-gas shift)} \tag{26}$$

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$$Kp_{CO} = \frac{x_{CH4} \cdot x_{H2O}}{x_{H2}^3 \cdot x_{CO}} \cdot \left(\frac{P_r}{P_a}\right)^{-2} = \frac{\mu_{CH4} \cdot \mu_{H2O} \cdot (\mu_{CO2}+\mu_{H2}+\mu_{CH4}+\mu_{H2O}+\mu_{CO})^2}{\mu_{H2} \cdot \mu_{CO}} \cdot \left(\frac{P_r}{P_a}\right)^{-2} \quad \text{(CO methanation)} \qquad (27)$$

Kp_i is the equilibrium constant of reaction i, x_i is the mole fraction of component i in wet basis, P_r is the pressure inside the reactor, and P_a is the ambient pressure. The value of Kp_i is directly computed from its definition (Equation 28):

$$Kp_i = e^{-\frac{G_i}{R \cdot T_r}} \qquad (28)$$

where G_i is the Gibbs free energy of reaction i (Equations 29 – 30), and T_r the temperature of the reactor. It should be noted that the Gibbs free energy of each component can be computed as $g_i = h_i - T_r \cdot s_i$ in Equations 29 and 30.

$$G_{RWGS} = g_{CO} + g_{H2O} - g_{H2} - g_{CO2} \qquad (29)$$

$$G_{CO} = g_{CH4} + g_{H2O} - 3 \cdot g_{H2} - g_{CO} \qquad (30)$$

Lastly, an energy balance is computed to obtain the temperature of the reactor (Equation 31), by using the enthalpies of reactions from Equations 21 and 22. At this point a simplification is taken, for which it is assumed that the exothermal energy released is used to heat the products from the inlet temperature to the final temperature achieved.

$$\sum_i Cp_i \cdot \mu_i \cdot (T_r - T_{in}) = -\Delta H_{RWGS} \cdot (\nu_{CO2} - \mu_{CO2}) - \Delta H_{CO} \cdot (\nu_{CO2} - \mu_{CO2} - \mu_{CO}) \qquad (31)$$

This method is repeated for each of the three reactors of the Figure 3. In those cases in which recirculation exists, it should be taken into account that the initial moles of reagents, ν_i, are the sum of the inlet and the recycled flow (for example, in reactor 3, $\nu_i = \nu_{i\,[29]} + 0.78 \cdot \mu_{i\,[30]}$).

The overall efficiency of the Power to Gas plant is computed as the quotient between the energy contained in the synthetic natural gas produced and the electricity consumed in the electrolysers and compressors (Equation 32).

$$\eta_{PtG} = \frac{\dot{m}_{SNG} \cdot \mathrm{LHV_{SNG}}}{W_{el} + W_{c[18]} + W_{c[20]}} \qquad (32)$$

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3.4. Economic model

The operation of the Power to Gas system combines two different strategies regarding the displacement of the nuclear power production: (i) the avoidance of partial load operation in the coal-fired power plant and (ii) the storage of nuclear electricity whenever the selling price is below the operating cost of the nuclear power plant.

The first strategy does not intend to operate the coal-fired power plant when is usually stopped, but to avoid partial loads whenever is operating (i.e., the coal-fired power plant will still operate during the same periods of the year, but always at nominal load). As shown in Section 3.1.1 the amount of nuclear electricity to be displaced to allow nominal operation of the coal-fired power plant is 441 GWh. The Power to Gas plant (210 MW of nominal capacity) will operate 2100 equivalent hours at nominal load following the first strategy in order to store 441 GWh from the nuclear power plant.

The second strategy accounts for those periods in which the selling price of electricity in the market is lower than the operating costs of the nuclear power plant. This electricity is stored through Power to Gas and then sold as synthetic natural gas at a higher price. In these cases, the CO_2 which has been previously stored is used, as the coal-fired power plant would not be in operation. In 2013, nuclear power plants were operated during 1,059 hours without profit (assuming an operating cost of 18 €/MWh [34]). Therefore, these hours are also included in the planning of the Power to Gas plant operation in order to avoid sales below the production cost.

In total, the Power to Gas plant will operate 3,159 hours in a year. As the present study aims to assess the standalone techno-economic feasibility of the PtG plant, the consumed electricity is considered to be bought to the nuclear power plant and the revenues from the sale of the synthetic natural gas will amortize the investment. The average price to be paid for the electricity takes into account both economic strategies described above and the average price over the total operation of the PtG plant is considered to be 13 €/MWh. Besides, the annual payment to amortize the loan is calculated through the French Amortization formula (Equation 33):

$$A = L\,\frac{i(1+i)^n}{(1+i)^n-1} \qquad (33)$$

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4. Results and discussion

In this section, the following results are presented: (i) the mass, temperature and pressure data of the simulated plant, which includes the coal-fired power plant with amine carbon capture and the Power to Gas facility, (ii) the comparison of the proposed solution (displacing nuclear electricity production) against the conventional partial load operation of coal-fired power plants, in terms of thermal efficiency and specific CO_2 emissions, and (iii) the economic results of the business model described in the previous section.

4.1. Simulation of the coal-fired power plant with amine carbon capture and Power to Gas

The results of the simulation (schemes of Figure 2 and Figure 3) operating at nominal load are presented in Table 3 (pressure drop is neglected as it has a low influence in the overall efficiency). The amine plant treats up to 33.45 kg/s of flue gas, from which 7.16 kg/s of CO_2 are captured. This amount represents only a 12.9% of the flue gas flow produced in the coal power plant. This is later combined with hydrogen to finally obtain 2.67 kg/s of synthetic natural gas, composed by 95.5 vol.% CH_4, 3.6 vol.% H_2 and 0.9 vol.% CO_2 (the composition of the synthetic gas at relevant points of the plant is presented in Table 4).

Table 3. Temperature, pressure and mass flows of the plant.

Point	Temperature [ºC]	Pressure [bar]	Mass flow [kg/s]
0	130.0	1.0	33.5
1	175.5	1.5	33.5
2	45.0	1.5	33.5
3	70.3	1.0	26.3
4	70.3	1.5	165.9
5	95.0	1.5	165.9
6	110.0	1.5	181.1
7	110.0	1.5	15.2
8	120.0	1.5	15.2
9	110.0	1.5	165.9
10	85.3	1.5	165.9
11	50.0	1.5	165.9
12	160.0	3.0	10.9
13	133.5	3.0	10.9
14	32.9	0.05	-
15	110.0	1.5	7.5
16	54.0	1.5	0.3
17	54.0	1.5	7.2
18	308.6	25.0	7.2
19	40.0	1.0	1.3
20	333.2	25.0	1.3

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21	591.6	25.0	38.5
22	300.0	25.0	38.5
23	300.0	25.0	30.1
24	40.0	1.0	10.4
25	300.0	25.0	8.5
26	460.5	25.0	8.5
27	197.4	25.0	3.5
28	197.4	25.0	4.9
29	300.0	25.0	3.5
30	354.4	25.0	16.0
31	300.0	25.0	16.0
32	300.0	25.0	12.5
33	300.0	25.0	3.5
34	155.7	25.0	2.7
35	155.7	25.0	0.9

Table 4. Molar compositions [%] in the methanation plant.

	CO_2 inlet (18)	H_2 inlet (20)	M1 outlet (21)	M2 outlet (26)	M3 inlet (29)	M3 outlet (30)	SNG (34)
CO_2	100.0	0.0	4.8	2.3	5.0	0.7	0.9
H_2	0.0	100.0	21.3	9.3	20.1	2.8	3.6
CH_4	0.0	0.0	24.1	29.4	63.4	74.4	95.5
H_2O	0.0	0.0	49.0	58.9	11.4	22.1	0.0
CO	0.0	0.0	0.7	0.1	0.1	0.0	0.0

The electricity consumption of the Power to Gas plant mostly comes from the electrolyser (210 MW), as the multi-compressors (9.45 MW) account only for the 4.5% of the total consumption. Besides, the heating demands prior the third reactor can be fulfilled with the cooling demands after reactors 1 and 2. The efficiency of the Power to Gas plant (Equation 32) is 59.7%. In the global picture (Figure 4), for each MWh displaced from nuclear power, 33.3 kWh are used in the amine plant, 41.65 kWh in the auxiliaries of the Power to Gas plant, and 576.7 kWh are stored in SNG, leading to an overall efficiency of 57.7%. The low energy penalization of the amine plant is related to the limited amount of flue gas from the coal power plant which are treated in the capture plant (only 12.9%).

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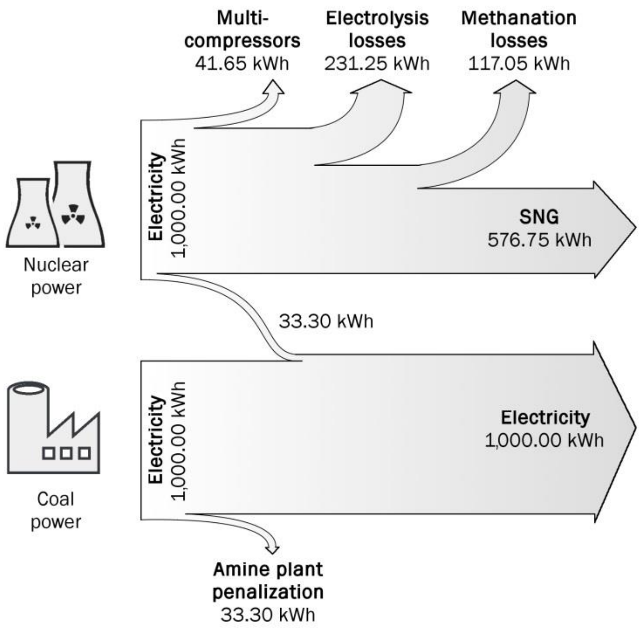

Figure 4. Sankey diagram of the displacement of electricity through Power to Gas.

4.2. Technical comparison between nuclear electricity displacement and coal power modulation

The conventional dispatch of electricity based on the regulation of the operating load of coal-fired power plants leads to a reduction in the thermal efficiency described by Equation 3. The proposed solution to operate the coal-fired power plants at full load by displacing electricity from nuclear power plants also reduces somehow the efficiency (Equation 20) due to the energy penalty of the CO_2 capture plant. Both efficiencies are compared in Figure 5, for operating loads between 40% and 100%, i.e., for power displacement between 210 MW (Power to Gas at full load) and 0 MW.

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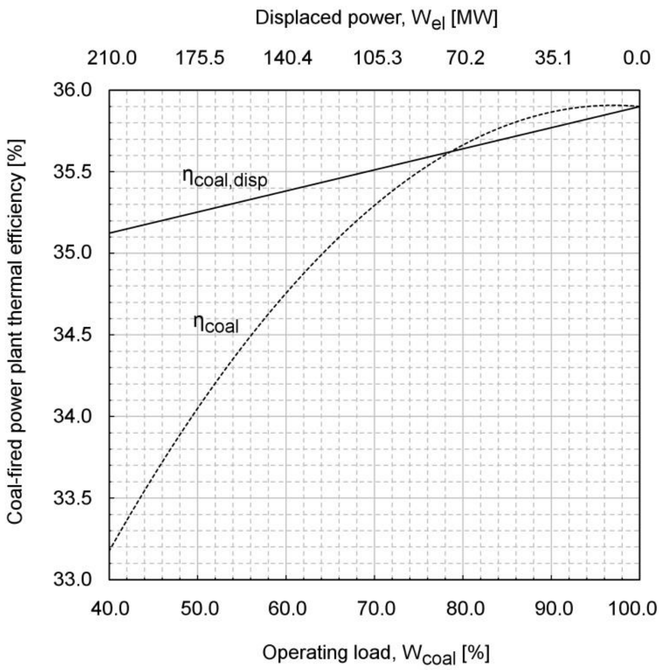

Figure 5. Comparison between η_{coal} vs. operating power and $\eta_{coal,disp}$ vs displaced power

Under conventional operation, the thermal efficiency diminishes 2.8 points when the operating load changes from 100% to 40%, while under the proposed electricity management solution, it decreases less than 0.8 points for nuclear power displacements of 210 MW. The penalization in $\eta_{coal,disp}$ is low because the percentage of flue gas to treat with amine scrubbing is always below 12.9%. It is worth to mention that from about 79% operating load to 100%, the conventional dispatch of electricity is preferable to the proposed method since the energy penalty of the carbon capture plant is avoided in the conventional operation (see Figure 5). Nevertheless, the overall performance of the system is clearly advantageous for the displacement method, as the thermal efficiency greatly increases compared to the conventional dispatch in the range 40% – 79% of operating loads.

Regarding the specific emissions of the coal-fired power plant, Figure 6 illustrates the comparison between conventional dispatch and nuclear displacement. The conventional dispatch based on regulating the operating load of coal-fired power plants makes specific CO_2 emissions, t_{CO2}, to increase 8.2% due to the loss in the thermal efficiency. Contrarily, the electricity dispatch based on displacing nuclear power leads to a reduction in the specific emissions as power is displaced, thanks to the second term of the right side of Equation 21 (i.e., thanks to amine carbon capture). The specific emissions of the proposed method may be as low as 0.90

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t_{CO2}/MWhe, which is a 12.7% lower than the emissions when operating at 40% load in the coal-fired power plant.

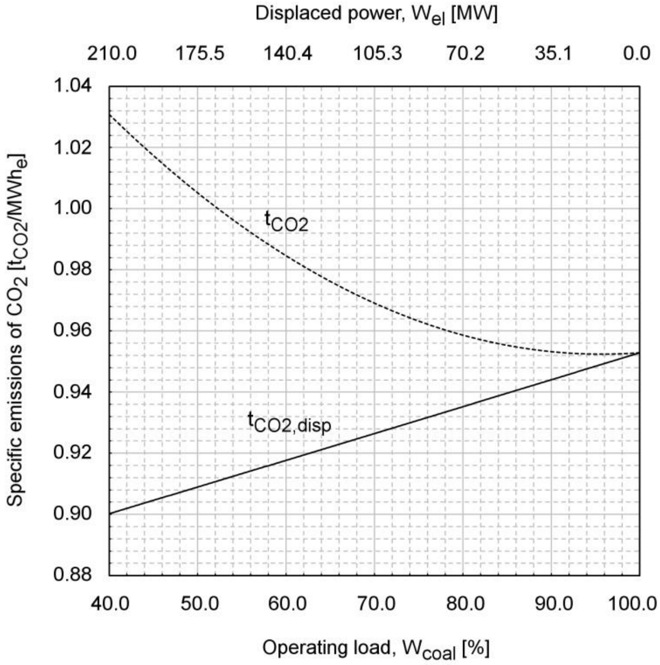

Figure 6. Comparison between t_{CO2} vs. operating load and $t_{CO2,disp}$ vs displaced power

4.3. Economic and environmental results under the proposed business model

The economic analysis of the base case scenario together with the cost equations considered in the study are presented in Table 5. An operation of 3,159 equivalent hours is assessed, with an electricity cost of 13 €/MWh, a CO_2 allowances price of 19 €/t_{CO2}, and selling prices for the SNG and the O_2 of 50 €/MWh [32] and 80 €/t_{O2} [35,36]. The amortization of the loan is considered to happen in 20 years with and annual interest of the 4%. Moreover, the volume of the reactors is calculated assuming a GHSV of 5,000 h^{-1} [37], and the catalyst is supposed to occupy the 60% of that volume [38].

Table 5. Economic analysis for the base case scenario.

	Cost [M€] or [M€/y]	Cost equation [M€] or [M€/y]	Parameters α, β	Ref.
CAPEX [M€]				
<u>Amine plant</u> (M€)				
Overall cost	4.35	$26.094 \cdot (\alpha/408)^{0.65}$	CO_2 captured [t/h]	[39]
<u>Electrolysis</u> (M€)				
Overall cost	84.00	$400 \cdot 10^{-6} \cdot \alpha$	Power [kW]	[40]

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Methanation plant (M€)				
H_2 multi-compressor	1.80	$0.267 \cdot (\alpha/445)^{0.67}$	Power [kW]	[41]
CO_2 multi-compressor	0.67	$0.267 \cdot (\alpha/445)^{0.67}$	Power [kW]	[41]
Reactor 1	0.12	$0.0189 \cdot \alpha^{1.066} \cdot \beta^{0.802}$	Diameter [m], Height [m]	[42]
Reactor 2	0.02	$0.0189 \cdot \alpha^{1.066} \cdot \beta^{0.802}$	Diameter [m], Height [m]	[42]
Reactor 3	0.04	$0.0189 \cdot \alpha^{1.066} \cdot \beta^{0.802}$	Diameter [m], Height [m]	[42]
Catalyst	0.07	$0.01242 \cdot \alpha$	Volume of catalyst [m^3]	[42]
Heat exchangers	0.25	$0.083 \cdot \alpha$	Cost of methanation plant [M€]	[32]
Other direct costs (M€)				
Installation	21.24	$0.10 \cdot \alpha$	Total CAPEX [M€]	[43]
Instrumentation & control	8.50	$0.04 \cdot \alpha$	Total CAPEX [M€]	[43]
Piping	25.49	$0.12 \cdot \alpha$	Total CAPEX [M€]	[43]
Electrical	10.62	$0.05 \cdot \alpha$	Total CAPEX [M€]	[43]
Building	10.62	$0.05 \cdot \alpha$	Total CAPEX [M€]	[43]
Land	2.12	$0.01 \cdot \alpha$	Total CAPEX [M€]	[43]
Indirect costs (M€)				
Engineering	14.87	$0.07 \cdot \alpha$	Total CAPEX [M€]	[43]
Legal expenses	4.25	$0.02 \cdot \alpha$	Total CAPEX [M€]	[43]
Construction expenses	8.50	$0.04 \cdot \alpha$	Total CAPEX [M€]	[43]
Contingency	14.87	$0.07 \cdot \alpha$	Total CAPEX [M€]	[43]
TOTAL:	212.38			
OPEX [M€/y]				
Amine renovation	0.10	$1.2 \cdot 10^{-6} \cdot \alpha$	CO_2 captured [t/y]	[44]
Catalyst renovation	0.01	$0.15 \cdot \alpha$	Initial catalyst cost [M€]	[32]
Electricity	8.62	$210 \cdot 10^{-6} \cdot \alpha \cdot \beta$	Electricity cost [€/MWh], equivalent operating hours [h]	-
Water	0.19	$1.47 \cdot 10^{-6} \cdot \alpha$	Water consumption [m^3/y]	[45]
O&M	6.37	$0.03 \cdot \alpha$	Total CAPEX [M€]	[43]
TOTAL:	15.30			
OUTCOMES [M€/y]				
Annual amortization	15.6	Equation 36		
OPEX	15.3			
TOTAL:	30.9			
INCOMES [M€/y]				
Natural gas	19.13	$10^{-6} \cdot \alpha \cdot \beta$	SNG selling price [€/MWh], SNG generated [MWh/y]	[32]
Oxygen	2.61	$10^{-6} \cdot \alpha \cdot \beta$	O_2 selling price [€/t_{O2}], O_2 generated [t_{O2}/y]	[35,36]
CO_2 allowance price	1.56	$10^{-6} \cdot \alpha \cdot \beta$	CO_2 allowance price [€/t_{CO2}], CO_2 consumed [t_{CO2}/y]	[46]
TOTAL:	23.29			
Annual benefit:	-7.63			

The annual benefit of the base case scenario is negative, what implies that the loan cannot be amortized. Actually, it can be seen that under current economic juncture the incomes barely covers the OPEX. An economic parametric study was performed looking for those combinations of operating hours and electricity prices that allow the Power to Gas to be economically viable for this proposed solution. The obtained results are presented in Figure 7.

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It can be seen that even with electricity prices of 0 €/MWh, a minimum of 3,000 equivalent hours are required to amortize the investment. Nevertheless, when the annual operation is increased to typical values of the industrial sector (~4,800 hours), a cost of up to 13 €/MWh can be assumed.

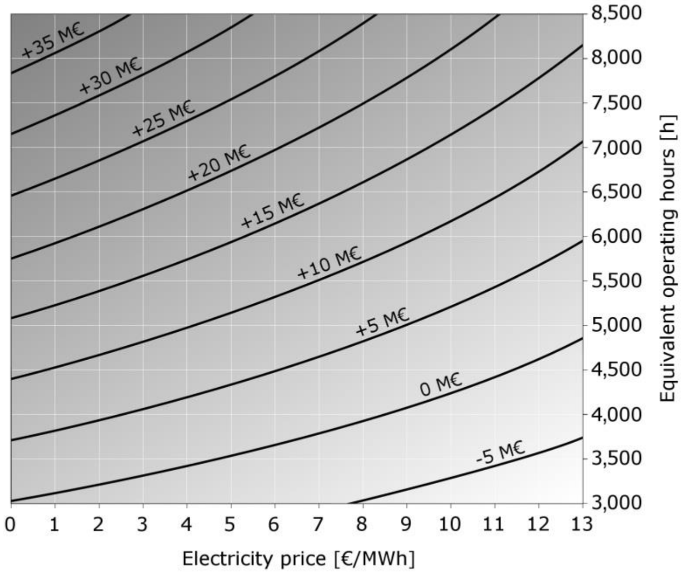

Figure 7. Annual benefit [M€] as a function of the electricity price and the operating hours.

Regarding the CO_2 emissions, the proposed concept reduces the annual specific emissions from 0.967 t_{CO2}/MWh to 0.913 t_{CO2}/MWh. However, the total emissions increase from 1.19 Mt_{CO2} to 1.55 Mt_{CO2}, since the full-load operating coal-fired power plant is producing a 36% more electricity than in the conventional method, what means that is consuming more fuel.

5. Conclusions

A new concept is proposed to modify the management of coal and nuclear power plants. This new concept will store electricity from the nuclear power plant in order to allow the constant operation of the coal power plant at nominal load avoiding the losses of efficiency related to part-load operation. Instead of using the fossil fuel power plant to regulate the global electricity production, the output of the nuclear plant will be controlled through a Power to Gas facility which stores the excess of nuclear production.

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The overall performance is more advantageous for the concept which includes storage from the nuclear power plant. The thermal efficiency of the coal power plant is increased in up to two percentual points from 33.2 to 35.2%) compared to the conventional dispatch in the range 40% – 79% of operating loads.

Under current economic situation, the concept is not economically feasible. The concept would become economically feasible for electricity prices of 0 €/MWh when the Power to Gas facility is operated during a minimum of 3,000 equivalent hours. When the electricity price takes values of 13 €/MWh and the annual operation of the facility is increased to typical values of the industrial sector (~4,800 hours), the economic feasibility of the concept is also foreseen.

Environmentally, the yearly specific emissions are reduced in a 5.6% when this concept is implemented while the total emissions are increased in a 30% since the coal-fired power plant is operated at full-load leading to an electricity production 36% higher.

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Nomenclature

Variables

A	[M€]	Annual payment
Cp	[kJ/kg/K] or [kJ/kmol/K]	Specific heat capacity
E	[MWh]	Electric energy
g_i	[J/mol]	Gibbs free energy of component i
G_i	[J/mol]	Gibbs free energy of reaction i
h	[h]	Operating hours
$\bar{h}$	[kJ/kg]	Specific enthalpy
i	[-]	Interest rate
Kp_i	[-]	Equilibrium constant of reaction i

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L	[M€]	Total amount of the loan
LHV	[MWh/kg] or [MJ/kg]	Lower heating value
$\dot{m}_i$	[kg/s]	Mass flow of component i
M_i	[kg/kmol]	Molar mass of component i
n	[-]	Total number of payments (years)
P	[bar]	Pressure
Q	[kW]	Thermal power
R	[J/mol/K]	Ideal gas constant
t	[t/MWh$_e$]	Specific carbon dioxide emissions
T	[K]	Temperature
w_i	[-]	Mass fraction of component i respect to coal fuel total mass
w'_i	[-]	Mass fraction of component i respect to residues total mass
W	[MW] or [%]	Electric power
x_i	[-]	Mole fraction (wet basis) of component i
x'_i	[-]	Mole fraction (dry basis) of component i
ΔH_i	[kJ/kmol]	Enthalpy of reaction i
η	[-]	Net efficiency
μ_i	[kmol]	Mole production of product i (Stoichiometric coefficient)
$\bar{\mu}_i$	[kmol/kg$_{fuel}$]	Mole production of product i per kilogram of consumed fuel (Stoichiometric coefficient)
ν_i	[kmol]	Mole consumption of reagent i (Stoichiometric coefficient)
$\bar{\nu}_i$	[kmol/kg$_{fuel}$]	Mole consumption of reagent i per kilogram of consumed fuel (Stoichiometric coefficient)

Subscripts

0	Nominal load
in	Initial / Inlet
[i]	Variable at point i of the scheme
a	Ambient pressure
c	Compressor
coal	Coal-fired power plant
des	CO_2 desorption process
disp	Displaced electricity
e	Electricity
el	Electrolyser
eq	Equivalent at full load
M	Moisture
MEA	Mono-ethanolamine
nucl	Nuclear power plant
r	reactor
s	isentropic
SNG	Synthetic natural gas
t	turbine
Z	Ash

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