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Benefits of coal-fired power generation with flexible CCS in a future northwest European power system with large scale wind power

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ABSTRACT

Coal-fired power generation with carbon capture and storage (CCS) is projected as a cost-effective technology to decarbonize the power sector. Intermittent renewables could reduce its load factor and revenues, so flexible capture unit operation strategies (flexible CCS) have been suggested to increase profits: CO_2 venting and lean- and rich-solvent storage. In this study we quantify the benefits of flexible CCS for both the power plant operator and the total Dutch power system. We use a unit commitment and dispatch model of the northwest European electricity system to simulate the hourly operation of two coal-fired power plants with flexible CCS in 2020 and 2030. We find that flexible capture unit operation hardly affects electricity generation (revenues) because the flexible operation capabilities are not often utilized. CO_2 venting is hardly used due to high CO_2 prices (43 €/tCO_2 in 2020 and 112 €/tCO_2 in 2030). The impact of rich-solvent storage is limited because of regeneration constraints of the base-load power plant. The main benefit of flexible CCS is an increase in reserve capacity provision by the power plant of 20–300% compared to non-flexible operation.

1. Introduction

The climate is changing as a result of anthropogenic greenhouse gas (GHG) emissions. In order to mitigate the adverse effects of climate change and keep the global temperature increase below 2.0–2.4 °C, a 50–85% reduction of GHG emissions may be needed by 2050, compared to 2000 (IPCC, 2007). The European Union intends to reduce its greenhouse gas emissions to 80–95% below 1990 levels by 2050 (EC, 2011a). As such, the power sector will need to shift to low-carbon generators, such as renewable energy sources, power plants with carbon capture and storage (CCS) and nuclear power plants (EC, 2011b).

Combining fossil fuel-fired power plants with large shares of intermittent renewable energy sources will have operational and financial complications for both the power plants and the system at large (Lew et al., 2013; Steggals et al., 2011; Stienstra et al., 2010). This also applies to coal-fired power plants equipped with CCS in power systems with stringent emissions reduction targets. The low variable costs of intermittent renewable generators give them an early position in the merit order, shifting the coal-fired plant's position from base-load toward mid-merit. The coal-fired power plants will have to balance variations in intermittent renewable power production and provide sufficient balancing reserves, resulting in more changes in operation with more frequent ramping and start-stop cycles. Moreover, the shift in the merit order decreases the capacity factor of coal-fired power plants. A lower capacity factor is a significant threat to the economic viability of these power plants, as they are capital intensive installations that require high capacity factors (>80%) to be able to be profitable (NETL, 2010).

Flexible operation of the capture unit ('flexible CCS') has been suggested as a solution to improve the flexibility and economic performance of power plants with CCS (Chalmers and Gibbins, 2007). Flexible operation of the capture unit enables its load – and associated energy demand – to be temporarily reduced independently from the load of the power plant. Thus, the net power output of the power plant can be temporarily increased. This increases the flexibility of the power plant, which is an asset for mid-merit power plants. Moreover, increasing the power production can boost power plant revenues when the electricity prices are high and/or from providing balancing services (Chalmers and Gibbins, 2007).

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List of acronyms

CAES	compressed air energy storage
CCS	carbon capture and storage
CHP	combined heat and power
GHG	greenhouse gas
NTC	net transfer capacities [MW]
PHES	pumped hydro energy storage
VOLL	value of lost load [€/MWh]
VORS	value of reserve shortage [€/MW]

The benefits of flexible CCS are dependent on the extent to which the energy demand of the capture unit can be reduced, as it determines the size of the energy penalty (the reduction in net power output). Compared to other CO_2 capture technologies, the energy demand of amine-type solvent post-combustion CO_2 capture can be reduced most through flexible CCS operation (Haines and Davison, 2009). Two flexible operating strategies for post-combustion CO_2 capture units have been reported in literature: venting and solvent storage. *Venting* consists of venting flue gas directly into the atmosphere, thereby bypassing the CO_2 capture unit and largely reducing its energy consumption. *Solvent storage* involves two extra reservoirs of solvent, which enables the capture unit to capture CO_2, whilst postponing the most energy-intensive steps of the capture process (Chalmers and Gibbins, 2007).

Several studies have investigated the effect of flexible operation of the post-combustion capture unit but they included some limitations from which we wish to improve. Nevertheless, they concluded that flexible operation often increases net power plant revenues. Important factors are the electricity and CO_2 prices, which respectively determine the extra revenue and extra costs in case of venting. Many engineering-focused studies assumed fixed (historical) electricity prices (Chalmers et al., 2011; Haines and Davison, 2009; Husebye et al., 2011; Patiño-Echeverri and Hoppock, 2012; Verbaan, 2011; Versteeg et al., 2013; Wiley et al., 2010). This basic approach does not take feedback effects of the flexible operation of capture units on the electricity price into account, nor their competition with other generators, and may therefore overestimate the benefits of flexible CCS. Four studies evaluated the benefits of flexible capture with a power system model, focusing on economics with generally less technical detail. Three out of these four only studied flexible venting, and report an increase in revenues of up to 10% for carbon prices <20 €/tonne (Cohen et al., 2011; Delarue et al., 2012; Ziaii et al., 2009). Just two out of the four studies investigated the benefits of supplying balancing reserves. Cohen reports that flexible CCS always reduces the balancing costs by up to 6%, and Delarue reports that it reduces balancing costs by up to 7% at carbon prices lower than 40–60 €/tonne (Cohen et al., 2013; Delarue et al., 2012). Also, only one study modeled a scenario with a high (20%) share of intermittent renewable sources (Cohen et al., 2013). Most importantly, none of the studies modeled a future, interconnected power system with renewables and electricity storage, even though interconnections and electricity storage are alternatives to flexible CCS for providing flexibility.

This study combines the engineering and economics approaches to comprehensively evaluate the benefits of the two types of flexible post-combustion capture units – venting and solvent storage – for coal-fired power plants in a future electricity market. A model of both types of flexible capture units is constructed, which serves as input for a comprehensive power system optimization model that includes the provision of balancing reserves, the presence of interconnections, electricity storage, and high shares of wind power. This study evaluates whether flexible capture unit operation of a coal-fired power plant increases the short-term profit of the power plant; and whether it reduces the total power system costs. The research focus is on the diverse and well interconnected Dutch electricity market in the context of the Northwest European electricity market, for the years 2020 and 2030. The future Dutch electricity mix is expected to have large shares of power plants with CCS and wind power (Ministerie van EL&I, 2011). Especially the application of CCS to coal-fired power plants appears promising, because these plants have high specific emissions, and can be readily retrofitted with a capture installation (IEA, 2012; Lucquiaud and Gibbins, 2011). The analysis is based on the 450-ppm scenario of the 2011 IEA World Energy Outlook because it foresees joint implementation of CCS and large scale wind power (IEA, 2011).

In this paper, the methodology of this research and a description of flexible capture units are first discussed, followed by a description of the power system model and input data. Model outcomes are then presented, from which conclusions are drawn and finally recommendations are presented.

2. Methodology

The benefits of flexible CCS are investigated by modeling the unit commitment and economic dispatch of two coal-fired power plants with (flexible) post-combustion capture, located in a future Dutch interconnected power system. The analysis distinguishes itself by using a two-step approach, resulting in a detailed simulation of both the capture unit as well as the power system at large (Fig. 1). In the first step, assumptions for the technical performance of flexible CCS are determined (purple boxes). In the second step, electricity market simulations are performed to determine the benefits of flexible CCS.

In the first step, the impact of flexible CCS on the energy use of the power plant and capture unit are explored with an Excel model (purple boxes). This static Excel model calculates the energy use of the capture unit based on assumptions about the energy use of its individual components. The energy use of the absorber, stripper, pumps, flue gas fans and compressors are calculated based on the flue gas flow, operating strategy and capture plant setup. The result of this step is an assumption about the energy use of the (flexible) capture unit as function of its work load. That assumption serves as input for the second step. Moreover, cost estimates for pay-back time calculations are provided based on literature (CESAR, 2011; Dutch, 2011; Klemeš et al., 2007; NETL, 2010).

In the second step, simulations are performed of the Northwest European power system for a full year using DNV GL's European Electricity Market Model which is built in PLEXOS, a commercial power system modeling software package[1] (red box in Fig. 1) (Energy Exemplar, 2013). Simulations are performed for four different configurations of (flexible) CCS. Based on seven main sets of input parameters (green boxes), the electricity market model optimizes hourly unit commitment and economic dispatch for each hour by minimizing the total short-term generation costs of the power system. The total system costs are equal to the sum of the fuel costs, emission costs, variable operation and maintenance costs, startup costs and a penalty in case of loss of load (value of lossed load, VoLL) or reserve capacity shortage (value or reserve shortage, VoRS). Appendix C lists the constraints and input parameters that are taken into account. The electricity market model determines the electricity price per region based on the short-run-marginal costs of its marginal generator (i.e. the shadow price of electricity generation), whilst assuming perfect competition. Reserve markets are modeled for the Netherlands by including reserve capacities

[1] PLEXOS for Power Systems is a power market simulation package that models the unit commitment and economic dispatch of (interconnected) power systems developed by Energy Exemplar.

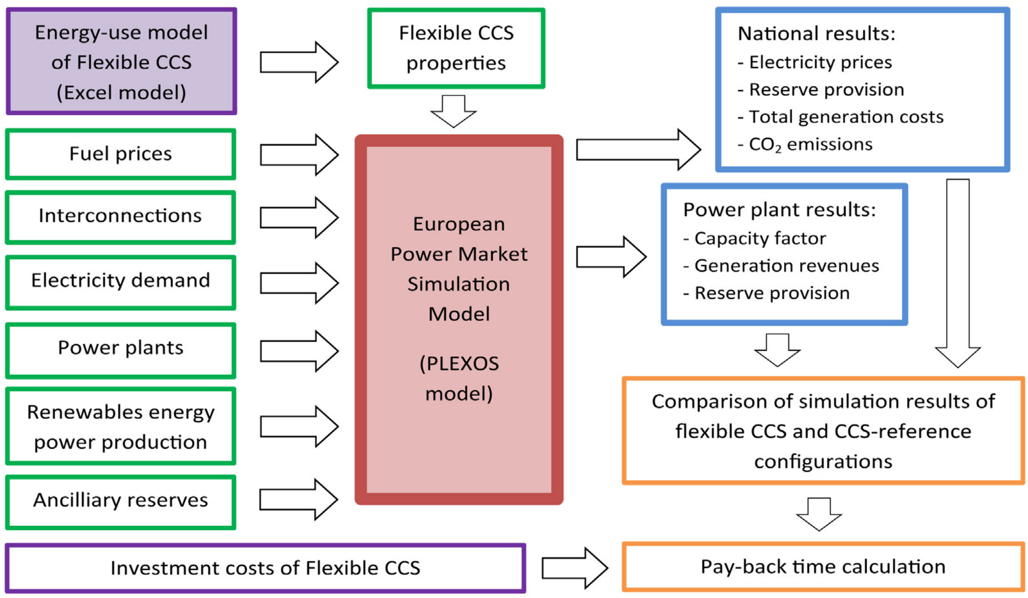

Fig. 1. Schematic overview of the approach of the study. The (purple) upper left and bottom left boxes indicate step 1: exploring the energy use of the (flexible) capture unit as a function of its load, and the investment costs of flexible CCS. The remaining (green) boxes on the left represent the standard input for PLEXOS and the PLEXOS input to model flexible CCS (upper box in the center). The large centered (red) box represents the modeling of the northwest European electricity market for each (flexible) CCS configuration for both scenarios 2020 and 2030. The two upper right blue boxes represent the simulation outputs at the power plant level and at the national level. The two bottom right boxes represent the process of drawing conclusions with respect to the benefit of flexible CCS: a comparison of the results of the flexible CCS configurations to the results of the CCS reference case, and calculation of the payback times as based on the possible difference between the flexible CCS and CCS-reference case results.

requirements for the different types of reserves. The electricity market model optimizes the provision of reserve capacity; it does not model the actual usage of reserve capacity, e.g. the provision of reserve *energy*.

The benefits of flexible CCS are determined using two sets of results: one at a national level and one at the power plant level (blue boxes in Fig. 1, Appendix A), which are further analyzed (orange boxes). As part of this analysis, the simple pay-back time of flexible CCS with solvent storage is calculated. It is based on the change in revenue of the installation from the flexible capture unit operation, which is defined as the increase in power plant generation revenue. The cost of flexible CCS with solvent storage consists of the additional investment costs.

A sensitivity analysis is performed to assess the robustness of the results for different future scenarios. Four model inputs are varied: (1) the CO_2 price, (2) the fuel prices in combination with the CO_2 price, (3) installed wind capacity in the Netherlands, (4) increase in storage size from 2 to 4 h of storage for flexible CCS with solvent storage case, which is an option evaluated in (Cohen, 2012; Versteeg et al., 2013). These four sensitivities are modeled for a set of 12 weeks in 2020 that are representative for the whole year.

2.1. Configurations

Four configurations are investigated by modeling two 725 MW_e coal-fired power plants with one of the following types of (flexible) CCS in the Dutch generation portfolio in 2020 and 2030 (Fig. 2).

Equipping two coal-fired power plants with flexible CCS is a credible scenario for the Netherlands. Four new coal-fired power plants are being built in the period 2010–2015, which will likely replace all older coal-fired units. By modeling two units with (flexible) CCS, their effect on the national power system is emphasized, and potential feedback effects between multiple units with flexible CCS can be accounted for. Only the flexible CCS configurations are altered: one fuel price and generator mix scenario is used in this analysis to represent the electricity market in 2020 and 2030.

1. 'CCS-Reference': two coal-fired power plants with a normal, fully integrated, post-combustion capture unit that always operates at the same load as the power plant.
2. 'Flexible CCS Venting': two coal-fired power plants with flexible CCS *Venting*: the ability to bypass the capture unit resulting in a 70% reduction of the capture unit energy penalty[2] compared to normal CO_2 capture unit operation.
3. 'Flexible CCS with solvent storage': two coal-fired power plants with flexible CCS with *Solvent storage*: the ability to reduce the energy penalty by 70% for up to 2 h of full load operation by storing CO_2-rich solvent. The rich-solvent has to be regenerated to CO_2-lean solvent at a later moment in time.[2]
4. 'Flexible CCS with solvent storage – 125% regeneration': two coal-fired power plants with flexible CCS with *Solvent storage* with +25% over-dimensioned regeneration capacity. Solvent storage reduces the energy penalty with 70% for up to 2-h full load operation.[2]

3. Flexible post-combustion capture unit

In this section the operation of four types of (flexible) CCS is elaborated and translated into a consistent set of assumptions for the net power generated with a state-of-the-art power plant equipped with a flexible capture unit. In addition, assumptions for the techno-economic parameters of flexible CCS are defined.

3.1. Power plant with CCS

In a conventional post-combustion capture unit, CO_2 is separated from flue gas through chemical absorption of CO_2 into a liquid solvent (e.g. a mixture of water and mono-ethyl-amine, MEA). This absorption occurs inside the absorber column as shown in Fig. 2. The liquid solvent containing the CO_2 (defined as the rich-solvent)

[2] Concepts such as 'energy penalty' and '125% regeneration capacity' are explained in more detail in Section 3.1.

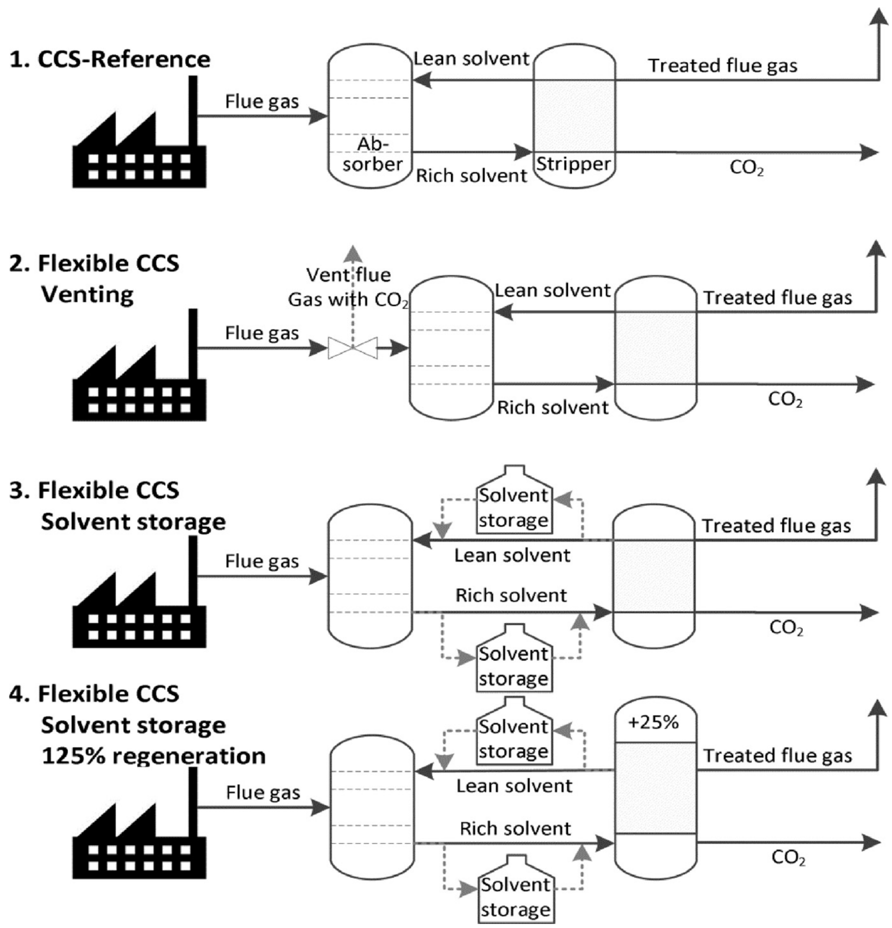

Fig. 2. Overview of the four carbon capture configurations studied in this paper. Dotted lines show the operation of flexible CCS.

is pumped toward the stripper column by solvent pumps. The CO_2 is desorbed from the rich-solvent in the stripper column by heating the solvent with steam that is extracted from the power cycle of the power plant. The solvent is now low in dissolved CO_2, or "lean", and led back to the absorber. The desorbed CO_2 is led to the compressor trains, where it is compressed for transport to a CO_2 storage site.[3]

The capture process requires energy that is supplied by the power plant, resulting in less power output compared to power generation without CO_2 capture. We use an Excel model to explore the impact of (flexible) CCS configurations on the net power production of the power plant that is used in the European Electricity Market Model. The underlying assumptions are listed in Appendix B in detail, with the following key assumptions:

- The total amount of CO_2 in the flue gas flow (in kg/s) is based on the carbon present in the fuel that is consumed in the power plant. Fuel consumption is modeled as a quadratic function of net power generation of the power plant in the electricity market model.
- The load of the absorber and stripper is defined by the solvent flow through the components compared to the solvent flow at full load operation of the power plant and capture unit.
- The load of the compressor trains is assumed to be proportional to the CO_2 flow through the compressor trains compared to the CO_2 flow at full load operation of the power plant and capture unit.
- Minimum loads for the absorber and stripper are 25% of full load and minimum load of a single compressor train (Chalmers and Gibbins, 2007; IEAGHG, 2012).
- The steam supply to the reboiler of the stripper is used for three energy functions: heating of rich-solvent (proportional to solvent flow), steam stripping (proportional to solvent flow) and desorption of CO_2 (proportional to the amount of CO_2 in the flow of rich-solvent to the stripper) (Lucquiaud and Gibbins, 2011).
- The effect of steam extraction from the power plant for the capture unit on the net power production depends on the load of both the power plant and the capture plant: the steam supply and returns are integrated in the coal-fired power plant. The optimal integration of the power plant and the capture unit depends on, amongst others, the type of capture process, the (relative) size of the capture plant, and the specific designs of the steam and power cycles (Lucquiaud and Gibbins, 2011). In this study the reduction in power output is assumed to be reversely proportional to the steam supply to the stripper, with a conversion factor based on an average for a state-of-the-art power generation unit for which the integration and impact on power output was investigated in detail.

Based on the above, a set of consistent assumptions was chosen for a hypothetical 725 MW_e coal-fired power plant, with a 175 MW_e reduction in net power output if operated with CO_2 capture at full load operation.

For a power plant with CO_2 capture, the optimum working point and operating window is influenced by many factors, such as the (future) market conditions, specific cost and design of the

[3] For a more comprehensive description see: Feron (2010), Metz and IPCC Working Group III (2005) and Wang et al. (2011).

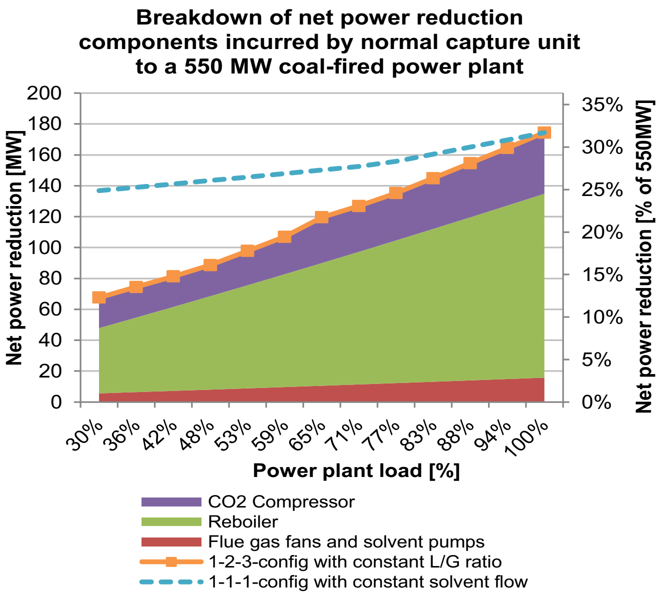

Fig. 3. Simulated decrease in net power output (i.e. energy penalty) as a function of load for a post-combustion capture unit without flexible CCS. The two configurations are described above, where the numbers refer to the number of absorber columns, stripper columns and compressor trains. Breakdown is shown for the 1-2-3 configuration.

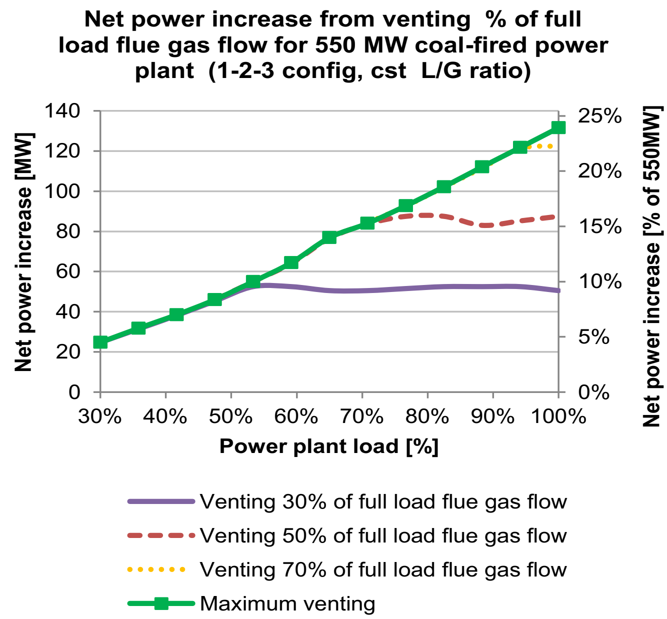

Fig. 4. The additional power output (MWe) resulting from venting (for all flue gas (solid green with marker), and percentages thereof: 70% (dotted yellow), 50% (dashed red) and 30% (solid purple)).

capture and power plant, as well as operating strategy. Flexible CO_2 capture capabilities add to this complexity. Two operating strategies for part load operation of capture plants are considered in this paper: constant *L/G* ratio and constant solvent flow. These are based on generally applied concepts of maintaining capture plant performance.

(1) Constant *L/G* ratio: this strategy is based on a constant ratio of vapor and liquid in the absorber, whilst maintaining a constant high capture rate. It is combined with a flexible plant configuration of multiple parallel processes: one absorber column, two parallel stripper columns and three parallel compressor trains, based on (Ziaii et al., 2011). This operating strategy is simulated with more detail with the Excel model, and used in the European Electricity Market Model.
(2) Constant solvent flow: this straightforward strategy maintains a constant solvent flow rate through the capture unit. It is included as a comparison, in combination with a more inflexible capture unit layout consisting of one absorber column, one stripper column and one compressor train.

The effect of the operating strategy and capture unit layout on the reduction in power output of the power plant is shown in Fig. 3. The figure shows that operating the capture unit with a constant *L/G* ratio and using a more flexible capture unit layout results in halving the net power reduction (orange line) compared to the more inflexible operation strategy. Switching off one of the three parallel compressor trains causes the slight bump in Fig. 3 at around 65% power plant load. In this analysis we assume the constant *L/G* ratio operating strategy because of the larger reduction in energy consumption of the capture unit when reducing the capture unit load.

3.2. Flexible CCS

Flexible operation of the capture unit (flexible CCS) can temporarily increase the power output by reducing the energy consumption of the capture unit in two ways, as shown in Fig. 2: venting and solvent storage. We use the Flexible CCS Excel model to determine the reduction in the energy penalty by applying venting or rich-solvent storage.

3.2.1. Flexible CCS Venting

Venting temporary lowers the energy penalty of the capture unit by letting (part of) the flue gas flow bypass the capture unit. As less flue gas enters the capture unit, less CO_2 is absorbed, allowing for a lower solvent flow rate and reducing the heat requirement for the regeneration of rich-solvent. Hence, *venting* reduces the load and the energy consumption of all components of the capture unit.

However, *venting* increases CO_2 emissions and emission costs because flue gas with CO_2 is directly emitted into the atmosphere (Chalmers and Gibbins, 2007), as would be the case without any capture of CO_2. As a result, the cost of applying venting is largely determined by the emission costs:

$$SRMC_{venting} = \frac{Load_v * Capture\ rate * Fuel\ input\ power\ plant\ w\ CCS * Fuel\ CO_2 content * (CO_2\ \ credit\ \ price - CO_2\ \ transport\ \ and\ \ storage\ \ cost)}{Increase\ in\ net\ generation\ from\ venting}$$

The net power increase from venting is dependent on the load level of the power plant, as shown in Fig. 4. The relation shows several nonlinearities, which are related to the minimum load levels of the compressors.[4] To limit modeling complexity, we assume a linear relationship between the power plant load and the gain in net

[4] The minimum load obstructs these components to further reduce their energy consumption when reducing the capture unit load. Furthermore, switching the component off causes a step in the energy reduction form energy consumption at minimum load to zero. Note that in practice we expect control systems will smoothen these nonlinearities.

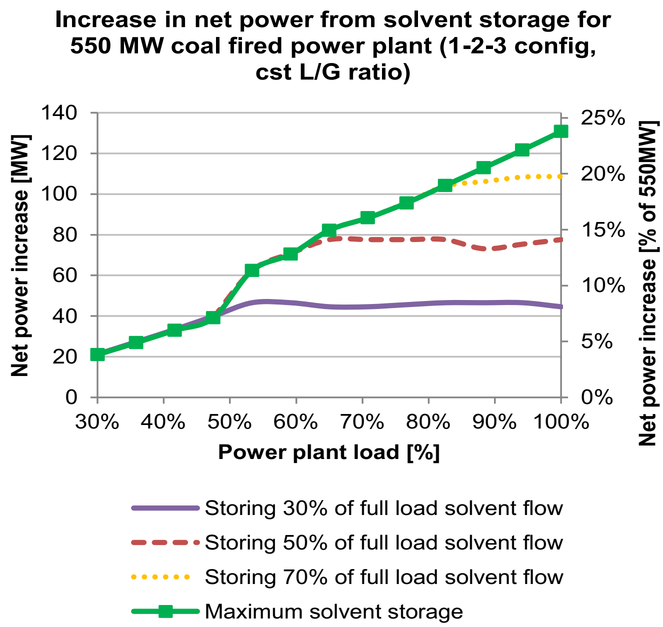

Fig. 5. Effect of rich-solvent storage on the net power output at different power plant loads and different amounts of solvent storage (for storing all rich-solvent leaving the absorber (solid green line with marker), and an amount equal to a percentage of the solvent flow at full load: 30% (solid purple line), 50% (dashed red line) and 70% (dotted yellow line)). This figure ignores possible storage sizes constraints.

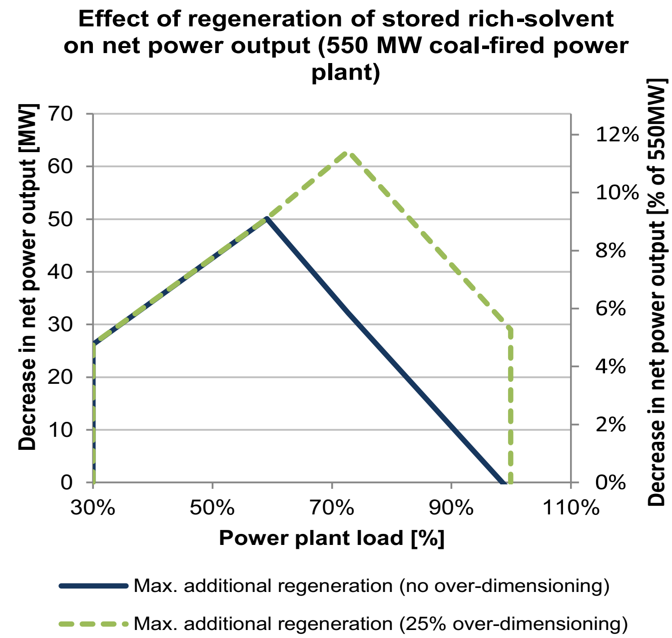

Fig. 6. Effect of regeneration of stored rich-solvent on the net power output, as a result of limitations in the availability of steam (from 30% to 60–70% power plant load) and from limitations in stripper and compressor capacity (from 60–70% to 100% power plant load). The green dashed line shows the effect for a capture unit with 25% over-dimensioned stripper and compressor capacity. This figure does not take possible storage constraints into account.

power generation from venting in the European Electricity Market Model.

3.2.2. *Flexible CCS with solvent storage*

Solvent storage temporary reduces the energy consumption of the capture unit by postponing the most energy intensive steps of the capturing process: rich-solvent regeneration and CO_2 compression. The full flue gas flow enters the capture unit and the CO_2 is absorbed by the solvent inside the absorber with the normal CO_2 capture rate (e.g. 90%). However, (part of) the resulting rich-solvent is stored in a storage tank, reducing the flow of rich-solvent through the stripper, thereby lowering the steam demand of the stripper, reducing the steam extraction from the power plant, and increasing the net power production of the power plant. As shown in Fig. 5, solvent storage reduces the load of the stripper and the compressor, lowering their energy consumption. A second (similar-sized) storage tank with lean-solvent is required to supplement the reduced amount of lean-solvent flowing from the stripper to the absorber to have a normal solvent flow rate through the absorber. The duration of flexible CCS with solvent storage is constrained by the size of the storage tanks and the amount of available lean-solvent (Chalmers and Gibbins, 2007).

During hours with low electricity prices, the stored rich-solvent is generated and stored as lean-solvent. This results in a temporarily increased energy penalty. This additional regeneration coincides with normal operation of the capture unit (Chalmers and Gibbins, 2007).[5]

The regeneration of stored rich-solvent is constrained by (1) the availability of additional steam that can be extracted from the steam cycle of the power plant at a given moment, and (2) by spare capacity of the stripper and compressor. Together, these two constraints create an operating window in which regeneration can occur (Fig. 6). The lower bound is set by the availability of steam: when the power plant operates at load levels lower than 60–70% of full load, the amount of steam available is limited, and the stripper and compressor are not used to available capacity. At loads of the power plant of more than 60–70% of full load, the spare stripper and compressor are limiting factors in the regeneration of stored rich-solvent.

At 100% of full load of the power plant, the full capacity of the stripper and compressor units is already utilized, leaving no spare capacity available for the regeneration of any rich-solvents that are stored. To still allow for regeneration, an extra configuration is included with 125% stripper and compressor capacity to investigate the effect of having the ability of regeneration of stored rich-solvent even when the power plant operates at full load.

3.3. *Coal-fired power plant with (flexible) CCS in the European Electricity Market Model*

In the European Electricity Market Model we assume that two coal-fired power plants, commissioned in 2010–2015 as ‘capture ready’ with a capacity of 725 MW_e each, are retrofitted with flexible post-combustion capture units. The properties of non-flexible retrofitted power plants are shown in Table 1. These parameters also apply to flexible retrofitted power plants, with the difference that the maximum ramp rates of flexible plants are further increased (see Table 2), and that the capture rate can vary when venting.

With the Flexible CCS Excel model we determine an energy penalty of 175 MW_e (24% of original net power capacity) at full load: retrofitting the capture unit reduces the maximum generation capacity from 725 to 550 MW_e. This is equivalent to an 11%-points efficiency penalty. The minimum stable level and the maximum ramp rates decrease proportionally to the reduction in the maximum capacity (IEAGHG, 2012). The power plants with flexible CCS are modeled by adding separate flexible CCS generators to each coal-fired power plant equipped with normal CCS: a ‘venting generator’ or ‘solvent pumped storage’. The venting generator is a power

[5] We assumed that the additional amount of solvent does not lead to significant increase in variable operation and maintenance cost of the capture unit.

Table 1
Techno-economic properties of coal-fired power plants with (flexible) CCS (DNV GL, 2013).

Property	With (flexible) CCS
Maximum capacity	550 MW_e
Minimum stable generation level	165 MW_e
Maximum ramp up rate	21.8 MW_e/min
Maximum ramp down rate	36.3 MW_e/min
Full load efficiency (incl. CCS)	38.3%
Variable operation and maintenance costs	5.31 €/MWh
Minimum up time	20 h
Minimum down time	15 h
Start cost	4000 €/start
Start fuel consumption	2688 GJ/start
Capture unit energy penalty	175 MW_e
Capture unit CO_2 capture rate	90%

plant with high CO_2 emission factor: applying flexible CCS venting to reduce the energy penalty is equivalent to power generation by this generator. The 'solvent pumped storage' generator is modeled as pumped storage power plant: applying flexible CCS rich-solvent storage is equivalent to power generation of this generator, and the regeneration of the rich-solvent corresponds to the pumping mode of this generator. The operation of the flexible CCS generators is dependent on the operation of the power plant with normal CCS. For example, the maximum net power generation of the flexible CCS generators is determined by the generation level of the power plant with CCS. The power generation from the flexible CCS generators does not (directly) affect the generation and fuel consumption of the corresponding coal-fired power plant.

Table 2 provides an overview of selected properties of the flexible CCS generators. Based on the Flexible CCS Excel model, we assume a maximum reduction in the energy penalty from applying flexible CCS of 70% of the 175 MW_e (full-load) energy penalty. This equals a reduction of 123 MW_e when the power plant with CCS operates at 100% load, which decreases linearly to 37 MW_e when the power plant with CCS operates at 30% load. As a result, 123 MW_e is the maximum generation capacity of the flexible CCS generators.

3.4. Investment costs of flexible CCS

We assume that flexible CCS Venting has no significant additional investments costs compared to a normal post-combustion capture unit. It is very likely that a normal capture unit can vent flue gas in case of emergency or during start-up or shutdown procedures (E.ON, 2011).

Flexible CCS with solvent storage requires additional upfront investments compared to a normal post-combustion capture unit. The bare erected cost (in €2010) of the additional investments for a 725 MW_e coal fired power plant consist of:

Table 2
The techno-economic properties of the flexible CCS generators in PLEXOS.

Property	Venting generator	Solvent storage
Maximum capacity	123 MW_e [a]	123 MW_e [a]
Minimum stable generation level	0 MW_e	0 MW_e
Maximum ramp up rate	6.1 MW/min[b]	6.1 MW/min[b]
Maximum ramp down rate	3.9 MW/min[b]	3.9 MW/min[b]
Maximum pump load	–	123 MW_e [a]
Pump efficiency	–	99%

[a] This is the maximum capacity when the power plant operates at full load. The value at a specific time depends on the load of the power plant with CCS.
[b] The ramp rate is proportional to the ramp rate of the base power plant, as the capture unit will at least be able to achieve this ramp speed (Black and Veatch, 2012; IEAGHG, 2012).

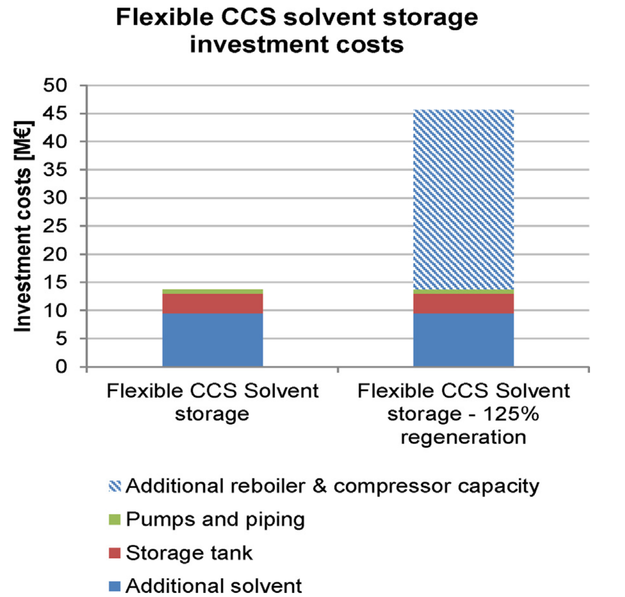

Fig. 7. Breakdown of the additional investment costs of flexible CCS with solvent storage, compared to the CCS-reference case. Values are based on: Dutch Association of Cost Engineers (2011), Klemeš et al. (2007) and NETL (2010).

- Additional solvent (30 wt% MEA): 9.54 M€ for 2 h of solvent storage (NETL, 2010).[6]
- Two solvent storage tanks for rich and lean-solvent each: 3.6 M€ for four tanks (Dutch Association of Cost Engineers, 2011).[7]
- Additional solvent pumps and piping: 0.7 M€ (CESAR, 2011; Dutch Association of Cost Engineers, 2011).[8]
- Capacity increase of stripper and compressor: 33 M€ (Klemeš et al., 2007) (For the flexible CCS with solvent storage – 125% regeneration case only.)[9]

Fig. 7 shows a breakdown of the investments costs. This calculated cost of solvent storage is 35% higher than the costs specified by Chalmers, and 30% lower than those calculated by Haines and Davidson (Chalmers et al., 2009; Haines and Davison, 2009). Given the 326 M€ investments costs of a normal post-combustion capture unit (NETL, 2010), adding solvent storage flexibility to the

[6] 2718 tonnes of MEA is required to capture 90% of the CO_2 emitted during 1 h of operation, considering a net-loading of 0.25 mol CO_2/mol MEA. At a price of 1.74 €2010/kg MEA, the solvent required to capture CO_2 emissions for 2 h will cost 9.5 M€.

[7] The additional 30% MEA solution consisting of 2718 tonnes of MEA and 6341 tonnes of water per hour of storage, has a density of approximately 1000 kg/m^3 and thus a volume of 9100 m^3. At a storage tank construction cost of 98.9 €/m^3, two tanks of 0.9 M€ each are required for 2 h of storage (storage tank costs are based on interpolating the costs of 6000 and a 13,500 m^3 tanks published in DACE (2011)).

[8] The pump capacity per hour is equal to storage capacity required for 1 h of storage. Based on the cost of a pump with a capacity of 315 m^3/h of €25,000 from DACE and a scale law of 0.7, we obtain a cost per pump of 0.27 M€. Two pumps are required: one per storage tank. Piping costs are estimated as 8% of the direct and indirect investment costs (CESAR, 2011). This amounts to 0.2 M€ in total.

[9] Over-dimensioning the regeneration capacity involves increasing the capacity of the drying and compression unit, the sorbent processing unit, sorbent reclaiming unit, reboiler and sorbent regenerator, circulation pumps and heat exchanger. We obtain the construction costs for the over-dimensioned components by applying the scale law assuming 0.8 as the scale factor: (original construction costs for regeneration components) * $(125\%/100\%)^{0.8}$. The original construction costs for the regeneration components are 55% of the total capture unit construction costs (Klemeš et al., 2007). Based on literature review, we obtain an overall capture unit construction costs of 558 €/kW (ZEP, 2011a,b; GCCSI, 2011; CESAR, 2011). The resulting original construction costs for the regeneration components is 55% of 307 M€ and the increase in construction cost from the over-dimensioning is 33 M€.

Table 3
Fuel prices used in the model (IEA, 2011).

	2020	2030
Coal price	3.1 €/GJ	3.1 €/GJ
Natural Gas price	8.8 €/GJ	10.9 €/GJ
Uranium Price	1 €/GJ	1 €/GJ
CO_2 credit price	43 €/tCO_2	113 €/tCO_2
CO_2 transport and storage costs[a]	10 €/tCO_2	10 €/tCO_2

[a] Based on ZEP (2011a,b).

Table 4
Future net transfer capacities of interconnections between the Netherlands and neighboring countries (ENTSO-E, 2012, 2011b).

NTC capacities [MW]	2020	2030
Belgium	3000	3000
Denmark	700	700
Germany	4000	4000
Norway	700	700
United Kingdom	1000	1000

capture unit increases the investment costs of the total capture unit by 5–20%.

4. The European Electricity Market Model

Input data of European Electricity Market Model have been derived from a number of sources, the most important ones being the WEO 2011 and the 2011 adequacy forecast of ENTSO-E (ENTSO-E, 2011a; IEA, 2011). Their respective 450 ppm and EU2020 scenarios project a coherent picture of fuel prices, generator mixes and demand projections for European countries in a future with limits on carbon emissions.[10] Such a low-carbon future is also considered in this study, with a generator mix consisting of high levels of wind power and power plants with CCS. An overview of the fuel prices is shown in Table 3.

4.1. Interconnection capacity

The future northwest European power system is modeled as five core regions (Netherlands, North Germany, South Germany, France, and Belgium) and eight satellite regions (Fig. 8). This interconnected system accounts for the effect of foreign hydro and intermittent renewable capacity on Dutch base load generators (including flexible CCS power plants). Each region is modeled without internal network constraints, but the interconnections between the regions do have a limited transfer capacity (Table 4). The transmission flows are modeled as DC-flows.

4.2. Electricity demand

The hourly load patterns of each of the regions are based on historic load patterns and the projected annual increase in electricity demand of 0.9% per annum according to the EU2020 scenario (ENTSO-E, 2013, 2011a). The main characteristics of the future Dutch electricity demand are shown in Table 5. In addition, a value of lost load was assumed of 10,000 €/MWh.

4.3. Thermal power plants

The future generator mixes of the northwest Europe regions are based on the current generator mixes (Platts, 2010), and the expected future developments from the EU2020 scenario (ENTSO-E, 2011a). In the core regions, power plants with a maximum capacity >100 MW are modeled on an individual basis, while the power plants in satellite regions are aggregated by technology. The following technologies are distinguished: coal steam turbine, natural gas combined cycle, gas turbine, heavy fuel oil steam turbine, nuclear, storage hydro, pumped storage hydro, run-of-river hydro, onshore wind, offshore wind, solar and biomass. The operation of thermal power plants is described by 16 techno-economic input parameters, which include flexibility, reliability and efficiency parameters, as listed in Table 12 in Appendix C. An overview of the installed generation capacity in the Netherlands is shown in Table 6.

The Dutch combined heat and power plants (CHP plants) are modeled with more detail than those in the other regions. Three types of Dutch CHP plants are distinguished: industrial heat supply, district heating and horticultural heat. The industrial CHP plants are modeled as ‘must-run’ by applying a minimum daily capacity factor of 75% (Energieraad, 2008). The district heating CHP plants often have gas-fired auxiliary boilers, and are therefore modeled with a gas-boiler opportunity cost discount that varies with the monthly heat demand. Horticultural CHP plants are mostly small gas turbines and gas engines, which are often combined with heat storage facilities. This adds flexibility to the dispatch pattern of these CHP plants and therefore they are not considered as ‘must-run’. The must-run character of CHP plants in the other regions is modeled through a constraint that defines a daily minimum capacity factor of 75% for these CHP plants.

4.4. Renewable energy sources

The wind, solar, and run-of-river hydro generators are modeled based on an installed generation capacity and an hourly availability profile. The installed capacities are based on the national renewable action plans (Beurskens et al., 2011; Resch et al., 2006), and the availability profiles are based on historic meteorological measurements (JRC, 2010; NOAA/OAR/ESRL PSD, 2008). The future wind and solar PV capacities in the Netherlands are shown in Table 6. Dutch wind power generation is projected to increase to 32.4 TWh in 2020 and 60.0 TWh in 2030, and solar PV generation to 0.6 TWh in 2020 and 2030.

Table 5
Characteristics of future electricity demand in the Netherlands used in the model (ENTSO-E, 2013, 2011a).

	2020	2030
Annual electricity demand	118 TWh	129 TWh
Peak demand	19.2 GW	21.1 GW

Table 6
Overview of installed generation capacity in the Netherlands for 2020 and 2030.

[GW]	2020	2030
Uranium	0.5	0.5
Coal (incl. CCS)	8.2	6.6
. . . of which district heating CHP	0.6	0.6
Gas	24.3	17.7
. . . of which industrial CHP	2.9	1.6
. . . of which district heating CHP	1.6	0.0
. . . of which horticultural CHP	2.5	2.5
Biomass	2.9	2.9
Hydro	0.2	0.2
Wind-onshore	6.0	6.0
Wind-offshore	5.2	13.8
Solar PV	0.7	0.7

[10] All capacities and energy flows in Sections 4 and 5 refer to electrical capacities and electricity flows.

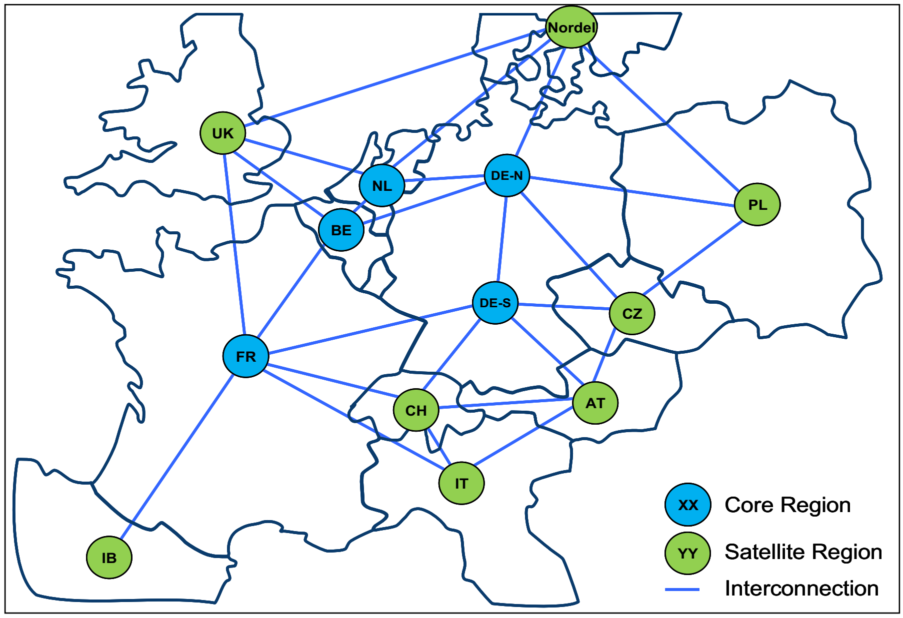

Fig. 8. Topology of the northwest European market model as modeled in the European Electricity Market Model (DNV GL, 2013).

4.5. Ancillary services

The reserve requirements of the Dutch power system are modeled by defining constraints for the minimum amount of reserve capacity that needs to be available within a timeframe specific per reserve type. The reserve requirements in the other regions are simulated with a reduction in the maximum generation capacity of those power plants. Four types of reserves are distinguished, which each consists of up- and down-reserves (Table 7):

1. Primary control reserve (ENTSO-E, 2009) is modeled as a fixed share of capacity that can only be used for supplying this reserve. Its size is 1.4% of maximum capacity for coal-fired power plants and 2.8% for gas-fired power plants.
2. Secondary control reserve (ENTSO-E, 2009; TenneT, 2013) is modeled by specifying the required total amount of reserve as well as the amount of reserve capacity that each power plant can provide.
3. Tertiary control reserve (ENTSO-E, 2009; TenneT, 2013) is modeled in a similar way as the secondary control reserve but with a larger reserve requirement.
4. Hourly control reserve (De Boer and Van der Veen, 2009) is an extra type of reserve that currently does not exist. Its purpose is to balance the forecast errors of large scale wind power. The size is based on the assumption of a 4% root-mean-square-error of the wind forecast error. Applying a 3-sigma confidence level results in a reserve capacity requirement of 12% of the installed wind generation capacity.

Power plants with flexible CCS have an extra option to provide reserves. In addition to normal reserve provision (e.g. provide up reserve by increasing its generation load), the capture unit can also provide reserves through flexible operation. Up reserves can be provided by the potential reduction of the capture unit load and down reserve capacity by the potential increase in the capture unit load. In addition, flexible CCS solvent storage can provide reserve by changing the amount of stored rich-solvent regeneration. Both reserve capacity (in MW) and reserve energy (in MWh) can be delivered this way. It is assumed that renewable energy sources cannot provide reserve capacity. This is in line with the current 'priority'-policy given to renewable energy sources with regard to access and delivery of electricity to the grid, prevailing in most northwest European countries.

5. Results

5.1. Benefits of flexible CCS at the power plant level

To determine the benefits of flexible CCS at the power plant level, we look at the capacity factor, the generation revenues and

Table 7
Overview of reserve modeling of the Dutch power market (ENTSO-E, 2009; TenneT, 2013).

	Primary control reserve [MW]	Secondary control reserve [MW]	Tertiary control reserve [MW]	Hourly reserve [MW]
Up and down Reserve size	n.a.[a]	350	1000	1344–2372[b]
Reserve available within	n.a.[a]	15 min	15 min	4 h
Max provision of reserves as percentage of the maximum capacity[c]				
Gas plants	1.4%	100%	100%	100%
Coal plants	2.8%	45–75%[d]	45–75%[d]	100%
Flexible CCS unit	n.a.	45–75%[e]	45–75%[e]	100%

[a] The amount of primary control reserve available depends on the plants online at that moment, as the primary control reserve provision is a fixed share of the maximum capacity.
[b] 12% of wind power installed (De Boer and Van der Veen, 2009).
[c] The 'max provision' is calculated by multiplying the ramp rate of the generator with the timeframe in which the reserve should be available.
[d] Higher value is used for the down reserve provision.
[e] Lower value is used for the down reserve provision.

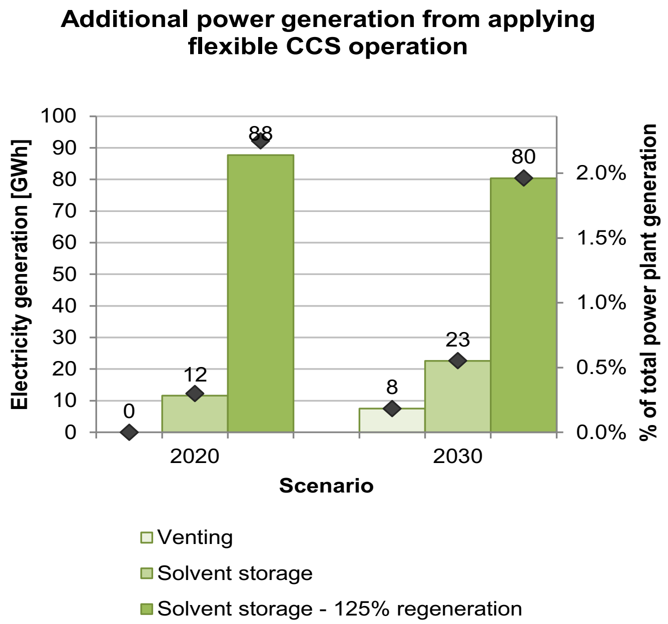

Fig. 9. Additional net power output from increasing the net power generation by applying flexible CCS operation. Black diamonds depict the share of flexible CCS generation as part of the total power plant generation.

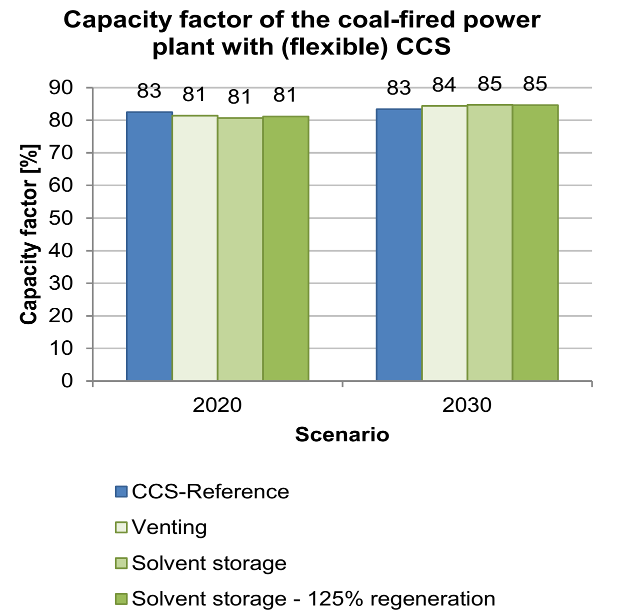

Fig. 10. Capacity factor of the power plant with (flexible) CCS. The capacity factor is the sum of the power generation under normal operation and the additional power generated from utilizing flexible CCS (if applicable). The maximum capacity of the coal-fired power plant (550 MW_e) was used for the capacity factor calculation. (As a reference: we also performed simulation for coal-fired power plant without CCS and with CCS in a model without reserve requirements. The resulting capacity factors in these simulations were 57% and 76% respectively. This shows that for the chosen CO_2 and fuel prices, CCS is preferable than no CCS.)

the reserve provision. These results are based on average values of the two coal-fired power plants with (flexible) CCS.

5.1.1. *Capacity factor*

The capacity factor is calculated by dividing the average hourly electricity generation by the maximum capacity. For the power plant with flexible CCS we use the electricity generated by the 'normal' power plant and the additional power generation from utilizing the venting or solvent storage flexibility of the capture unit (if applicable). Fig. 9 shows the additional generation from applying flexible capture unit operation for each type of flexible CCS for 2020 and 2030. Power generation from venting is zero in 2020 and small (7.5 GWh[11]) in 2030, compared to the total electricity generation of about 4 TWh of the entire coal-fired power plant with (flexible) CCS. Flue gas venting is seldom applied because the costs of extra emissions are allocated to it. This results in high specific emissions (3.7 tonne/MWh) and high associated emission costs: 132 €/MWh in 2020 and 416 €/MWh in 2030 given the assumed CO_2 prices.

The power generation from applying rich-solvent storage in the flexible CCS with solvent storage case is 4–7 times lower than that of the flexible CCS with solvent storage – 125% regeneration case in both 2020 and 2030. The flexible CCS with solvent storage – 125% regeneration case generates more electricity from rich-solvent storage in both years as a result of its increased stripper and compressor capacity. Without the additional regeneration capacity, regeneration is assumed to be either limited to hours in which the coal-fired power plant with Flexible CCS with solvent storage is operating at part load because of a low electricity price (regardless of possible stored rich-solvent regeneration). Or it is limited to hours in which the power plant reduces its generation to regenerate stored rich-solvent, thereby forcing a more expensive power plant to generate electricity (increasing the total generation costs for the Netherlands).

[11] The electricity generation from venting in 2030 is not the result of high electricity prices, but the result of a higher demand for down reserve capacity in 2030: see Section 5.1.3 'Reserve provision'.

The electricity generation from flexible CCS with solvent storage is 12 GWh in 2020 and 23 GWh in 2030. The electricity generation from flexible CCS with solvent storage is higher in 2030 than in 2020 because the coal-fired power plant runs more often at part-load as a result of the increase in renewable generation capacity in the Netherlands and neighboring countries. The increase in hours of part-load operation enables more regeneration of stored rich-solvent. In addition, the increased part-load operation reduces the benefit of the 125% over-dimensioned stripper and regeneration capacity, leading to lower annual power production by flexible CCS with solvent storage – 125% regeneration case in 2030 compared to 2020.

Fig. 10 shows the capacity factor of the power plant with (flexible) CCS for the four different configurations, for the years 2020 and 2030. The flexible CCS cases have a 1–2%-points lower capacity factor in 2020 compared to the CCS-reference case in 2020 and a 1–2%-points higher capacity factor in 2030. The differences between the CCS-reference and the flexible CCS cases are limited: the 8–88 GWh of electricity generation by applying flexible CCS operation (Fig. 9) is 0.2–2% of the total electricity generated (4 TWh) by the coal-fired power plant with (flexible) CCS. The difference in capacity factors between the flexible CCS cases is caused by the different nature of the flexible CCS cases, resulting in different impact on dispatch pattern and provision of reserve capacity.

5.1.2. *Electricity generation net revenues*

The electricity generation net revenues are defined as the revenues from electricity minus all variable generation costs (e.g. fuel, emission, variable operation and maintenance and start costs).

Fig. 11 shows that the electricity generation net revenues power plants with CCS increases from around 49 M€ in 2020 to around 86 M€ in 2030 as a result of higher electricity prices. The revenues of coal-fired power plant with flexible CCS venting are slightly lower compared to revenues of the CCS-reference case: −1.5%

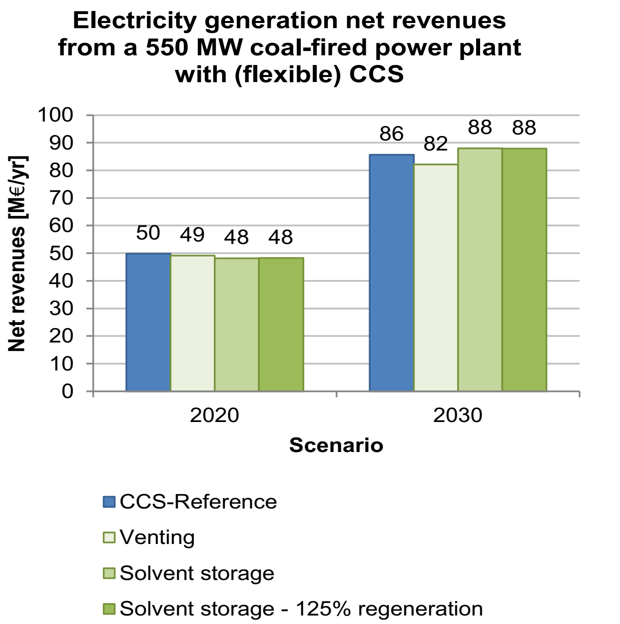

Fig. 11. Electricity net revenues of the coal-fired power plant with (flexible) CCS for all configurations and both scenarios (2020 and 2030). The electricity net revenues of the power plant are defined as its total revenues from the electricity market minus its variable generation costs. The 'electricity price' obtained in PLEXOS is the cost price of electricity and can differ from the actual market price.

(−1 M€) in 2020 and −4 M€ in 2030. The decrease in generation revenues in 2030 is partially caused by the 3.2 M€ emission cost incurred by flue gas venting to be able to provide down reserve capacity.[12]

Fig. 11 also shows that the differences in generation net revenues of the coal-fired power plant between the CCS-reference case and both flexible CCS with solvent storage cases are small: 3% (1.5 M€) lower revenues in 2020 and 2.5% (2.4 M€) higher revenues in 2030 for flexible CCS with solvent storage. This increase in revenues for flexible CCS with solvent storage leads to a payback time of flexible CCS with solvent storage of 6 years and for flexible CCS with solvent storage–125% regeneration of 19 years.[13]

5.1.3. *Up reserve provision*[14]

The cumulative up reserve provision (GWh) is the sum of the up reserve capacity[15] provided (GW) for the duration of the period it is provided (in hours). The cumulative up reserve provisions of the coal-fired power plant with (flexible) CCS are shown in Fig. 12: the blue bar shows the up reserves provided by the coal-fired power plant by increasing its coal input, while the green bar shows the additional up reserves provided by flexible CCS.

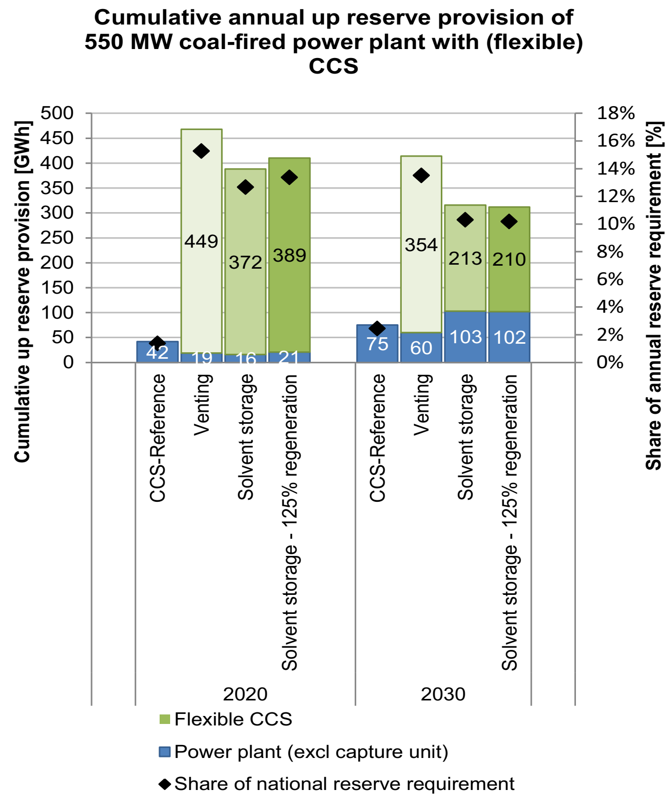

Fig. 12. The amount of up reserve capacity provided by the power plant with (flexible) CCS in the scenarios 2020 and 2030. The blue bottom part represents the amount of up reserve provided by spare generation capacity of the power plant itself. The green upper part is the reserve capacity provided by the flexible capture unit. The black diamond represents the share of the annual secondary up reserve capacity requirement of the Netherlands that is provided by the power plant with flexible CCS.

Fig. 12 shows an increase in the up reserve provision from less than 50 GWh for the CCS-reference case to 375–450 GWh in the flexible CCS cases in 2020, and an increase from 75 GWh to 310–414 GWh for the flexible CCS cases in 2030. The 450 GWh corresponds to 17% of the required annual up reserve capacity of the Netherlands. Using the average secondary reserve capacity price of the German market, with 13% of national demand provided by wind and solar PV in 2013, of 4.1 €/MW (1st quarter of 2014), the 450 GWh would corresponds to revenues of 1.8 M€ per year (Regelleistung.net, 2014).

The large increase in up reserve provision comes from the large up reserve provision from the flexible capture unit: +370 to +410 GWh in 2020 and +210 to +350 GWh in 2030. The flexible capture unit provides 'spare generation' capacity for the up reserve (either from applying flue gas venting or from applying rich-solvent storage). Up reserve provision from flexible capture unit is preferred to up reserve provision by a power plant without flexible CCS (from a system cost minimization perspective): the up reserve provision from the flexible capture unit does not incur additional costs (assuming the coal-fired power plant is running), whereas a power plant without flexible CCS must operate at part load and therefore generates at a reduced efficiency. The up reserve provision of the flexible capture unit in 2030 is less than for 2020 because the coal-fired power plant runs more often at part-load in 2030.

The coal-fired power plant with flexible CCS venting provides more up reserve provision than the coal-fired power plant with flexible CCS with solvent storage: 449 GWh compared to

[12] Note that the model optimizes the national Dutch power system, and that dispatch decisions might therefore not be optimal from a power plant operator perspective, who seeks to maximize profits.

[13] Based on investments costs of 14 M€ and 46 M€ for Flexible CCS with solvent storage and flexible CCS with solvent storage flexible CCS with solvent storage – 125% respectively. Payback times for 2020 electricity generation revenues are not calculated as the power plants with Flexible CCS with solvent storage flexible CCS with solvent storage had lower revenues from electricity generation than the CCS-reference case.

[14] We will not discuss the results with respect to the down reserve. The assumption that wind turbines do not provide down reserves resulted therefore in very high down reserve costs. However, in reality it seems more likely that wind turbines are allowed to provide down reserves, lowering the difference between the flexible CCS cases and the CCS-reference case.

[15] Notice that we focus on the reserve *capacity (MW)* and not the actual provision of reserve *energy (MWh)*. Hence, the provision of reserve capacity does not incur operating costs directly such as fuel consumption, but it can result in operating at a less efficient operating point.

Table 8
Impact of flexible CCS on average electricity price, CO_2 intensity and wind curtailment of a future Dutch power system.

	Average Dutch electricity price [€/MWh]		CO_2 intensity of Dutch electricity [kg CO_2/MWh]		Wind curtailment [curtailed wind (GWh)/potential wind generation (GWh)]	
	2020	2030	2020	2030	2020	2030
CCS – reference	60.8	77.2	265	155	60 GWh (0.2%)	5206 GWh (7.8%)
Flexible CCS venting	60.7	77.7	261	156	69 GWh (0.2%)	5087 GWh (6.6%)
Flexible CCS solvent storage	61.0	77.6	265	152	79 GWh (0.2%)	4961 GWh (7.5%)
Flexible CCS solvent storage – 125% regeneration	60.9	77.4	265	151	75 GWh (0.2%)	4940 GWh (7.4%)

380 ± 9 GWh in 2020 and 354 GWh versus 211 ± 2 GWh in 2030. The up reserve provision of all three flexible CCS cases is constrained by the power generation of the coal-fired power plant. In addition, the up reserve provision in the two flexible CCS with solvent storage cases is also constrained by the amount of lean-solvent available.

5.2. Impact of flexible CCS on other national parameters

We also assessed the impact of flexible CCS on the year-average electricity price,[16] the CO_2 emission intensity of the Dutch power sector, and the amount of wind curtailment within the Netherlands (Table 8). Differences between the CCS-reference case and the three flexible CCS cases are (very) small: less than 0.6% for the electricity price, less than 3% for the emissions (venting gives a small increase in specific emissions when used whereas solvent storage a decrease) and less than 2% for wind curtailment.

The impact of flexible CCS on these indicators is small due to the small increase in generation capacity flexible CCS can provide (123 MW per capture unit versus a peak load of 19–21 GW). Small changes can be attributed to the reserve provision of flexible CCS but also to variations in unit commitment and dispatch as part of the national least cost optimization.

5.3. Sensitivity analysis

A sensitivity analysis was performed for changes in the storage size of solvent, CO_2 price in combination with the fuel prices, installed wind capacity and the CO_2 price (Table 9). Runs were performed for a selection of 12 weeks to represent the year 2020 and all results in this section are based on those 12 weeks. The results show that these variations in inputs mainly impact the dispatch of the coal-fired power plant itself, rather than the use of the flexibility of the flexible capture unit.

5.3.1. Solvent storage capacity of 4 h

Increasing the solvent storage capacity from 2-h to 4-h increases the generation from using flexible CCS with solvent storage by up to 50% (increasing generation revenues by 0.2–0.3 M€ per year). The reserve provision is not affected. However, the increase in revenues does not justify the doubling in investment costs for 4-h solvent storage. The 4-h solvent storage option closely resembles that of the 2-h solvent storage. The sensitivity of 2-h and 4-h storage is therefore reported together.

5.3.2. CO_2 price

Fig. 13 shows the influence of changing the CO_2 price on the power plant generation, reserve provision and electricity generation revenues. It shows that both power generation and revenues of the power plants with (flexible) CCS decrease in case of a lower CO_2 price as result of the power plant is moving to a later position in the merit-order and lower electricity prices. The shift in merit-order dominates the impact of lower CO_2-price.

The usage of solvent storage increases as a result of the increase in part-load operation. However, the benefit of over-dimensioning the regeneration capacity is reduced: the electricity generation from the 125%-regeneration cases converges to the normal flexible CCS solvent storage case. Flexible CCS venting becomes much more attractive at lower CO_2 prices because the associated emissions costs are reduced: the amount of venting increases from 0 to 250 GWh for the low CO_2 price case.

5.3.3. CO_2 price and fuel prices

The results of CO_2 and fuel price sensitivity case combined are mainly influenced by the results due to a change in the CO_2 price: the obtained results are similar to the results of the CO_2 price sensitivity case. The only exception is that the change in fuel prices affects the generation revenues of venting generation, which are 10 M€ higher in the 'low CO_2 price and high fuel price' case compared to the base case because of the higher electricity price-levels.

5.3.4. Installed wind capacity

In both the base (11.2 GW) and low (6 GW) wind case, the power plants with CCS are in a base-load position. Hence, the results of both cases are quite similar. In the high wind case the power plant with CCS operates more often at part-load (i.e. as a mid-merit order power plant), which reduces the load factor of the power plants by 19% and increases the utilization of the flexible capture units with 20–120%.

6. Discussion

6.1. Comparison of flexible CCS to other technologies

Flexible CCS competes with other flexibility options, such as electricity storage and gas-turbine peaking plants. Although the two latter options do not change the flexibility of the coal-fired power plant with CCS, they do change the flexibility of the portfolio of the power plant owner and of the system as a whole.

Flexible CCS with solvent storage primarily competes with other electricity storage options. Examples of alternative storage technologies are: pumped hydro energy storage (PHES), compressed air energy storage (CAES) or (flow) batteries. Flexible CCS with solvent storage differs from these storage alternatives because it offers a 'constrained flexibility' in two ways: the coal-fired power plant must be dispatched for the solvent-storage to be available, and the amount of electricity generation or energy storage of solvent storage depends on the load of the coal-fired power plant.

The investment costs of flexible CCS with solvent storage are comparable to other storage technologies at 56 €/kWh (±35%) (Section 3.4). The reported investment costs of other storage technologies show a wide range, depending on the technology, location and operating pattern. Typical values are: PHES 10–115 €/kWh; CAES: 3–85 €/kWh and batteries: ≫50 €/kWh (Akhil et al., 2013; Díaz-González et al., 2012).

[16] The 'electricity price' defined by the short-run-marginal cost of the marginal generator and can differ from the actual market price.

Table 9
Overview of the four sensitivity cases investigated for the flexible CCS configurations for the 2020 scenario.

Sensitivity case	Altered input	Unit	Low-case	Base-case	High-case
Increased solvent storage capacity	Solvent storage size	h		2 h	4 h
CO_2 credit price	CO_2 credit price	€/tCO_2	21.3	42.6	63.9
Fuel and CO_2 credit price	CO_2 credit price	€/tCO_2	63.9	42.6	21.3
	Gas price	€/GJ	4.4	8.8	13.2
	Coal price	€/GJ	1.6	3.1	4.7
Wind capacity	Installed wind capacity	GW	6	11.2	18

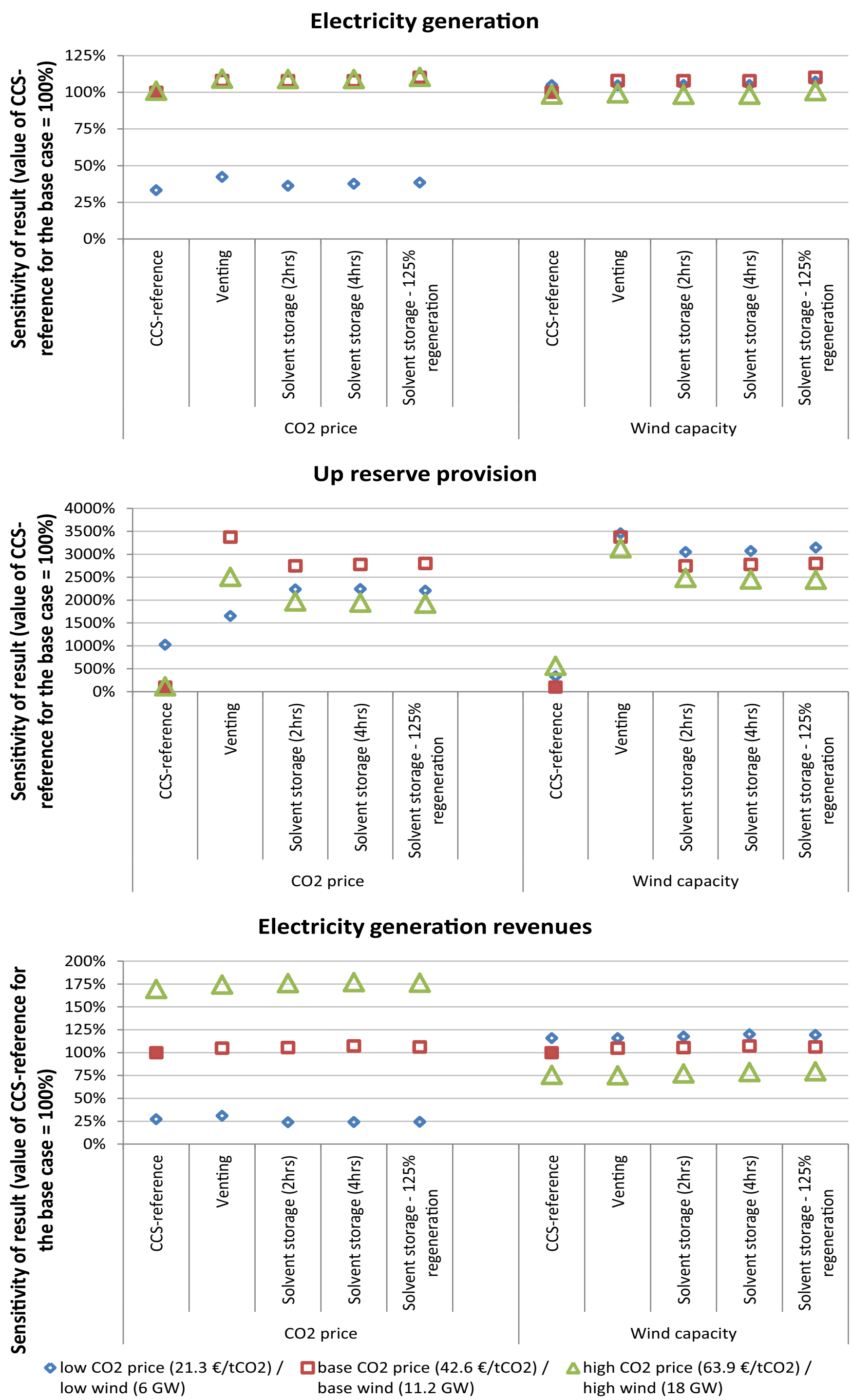

Fig. 13. Sensitivity of outcomes to variations in CO_2 price and installed wind capacity. The three markers indicate the range over which the value (e.g. power generation, up reserve provision, electricity generation revenues) varies from changing the CO_2 price (21.3 €/tCO_2 (low-case), 42.6 €/tCO_2 (base-case) and 63.9 €/tCO_2 (high-case)) or the installed wind capacity (6 GW (low-case), 11.2 GW (base-case) and 18 GW (high-case)). The squares represent the value of the base case for each sensitivity analysis.

The 'constrained flexibility' of the flexible CCS with solvent storage lowers the net revenues compared to an alternative portfolio of a coal-fired power plant with normal CCS and a stand-alone energy storage option in two ways. During hours of low electricity prices, stand-alone energy storage can fill up while the coal-fired power plant is switched off. The operator of the power plant with flexible CCS has to choose between switching off both the power plant and storage, or running the coal-fired power plant at a loss at 60–70% load to regenerate stored rich solvent. Moreover, hours of low electricity prices are often caused by high renewable production. Supplying up reserves is relatively profitable during these hours, as the available up reserve capacity is limited. Again, the plant operator has to choose between unprofitable dispatch or not using the flexible capabilities of the capture unit to provide up reserve capacity.

The 'back-up' power generation functionality of venting is comparable to a peaking plant such as an open-cycle gas turbine (OCGT). The investment costs of flexible CCS venting are small assuming that capture units require venting capabilities as an emergency operation, whereas the investment costs of an OCGT are substantial: 400–500 €/kW (Black and Veatch, 2012). Still, the functionality of flexible CCS is also reduced by 'constrained flexibility'. Therefore, an OCGT is a more flexible but also more expensive back-up generation source.

6.2. Improvements of model

Although comprehensive, the analysis could be expanded in three aspects:

6.2.1. Electricity market model

The electricity market model optimizes the dispatch by minimizing the short-term total generation costs of the entire system and hence does not maximize the profits of the individual power plants or generation portfolios. We use this approach because it accounts for feedback loops between the power system and the dispatch of the flexible CCS plant. However, situations may occur where the dispatch of a power plant is beneficial from a system perspective, but not necessarily from the perspective of the power plant operator. The modeled benefits of flexible CCS at the power plant-level could therefore be an underestimation. For example, other studies show that the lowest-cost power plant dispatch for the whole system is different from a power plant dispatch where power plant operators maximize their profits (Cohen et al., 2011; Ziaii et al., 2009).

6.2.2. Reserve modeling

Our results show that reserve provision could be a significant source of revenues for flexible CCS. Further research is needed to quantify this potential, where two modeling aspects are particularly important.

First of all, it is important to accurately model reserve markets to determine the reserve price. Ideally, the model simulates bids from generators to provide reserves, which are accepted in order of increasing price. Next, the model determines which shares of reserve capacity actually needs to be activated, and simulates their activation. This way, the reserve price is based on supply and demand of reserves, can generators be remunerated for their reserves, and can extra fuel and CO_2 costs be accounted for.

In contrast, the actual generation of reserve power (MWh) is not considered in the European Electricity Market Model. This could affect the results, as the utilization costs of flexible CCS Venting (related to extra CO_2 allowances) are higher than those of flexible CCS with solvent storage (related to fuel costs for regeneration of solvent, and indirect costs related to the loss of generation capacity during regeneration of stored rich-solvent). Therefore, the actual contribution of flexible CCS Venting to up-reserves could be smaller than the model outcome, especially if remunerations per MWh of reserves supplied are low.

Secondly, the rules of the reserve market affect the revenues of reserve provision, mostly downwards. These include the reserve sizing methodology and the types of generators that can supply reserves:

- If the reserve sizes would be reduced (e.g. by intra-day trade or allowing net balancing via the interconnections), this would result in lower reserve prices, and reduce the benefit of flexible CCS.
- If wind power could supply reserves, this would lower the reserve revenues for thermal generators, because reserve prices are especially high during high wind, low load situations.

6.2.3. Flexible operation of power plants with CCS

Little information is available on the dynamic performance of integrated flexible power plants with capture unit. Only Lucquiaud concluded that even a retrofitted coal-fired power plant can operate flexibly if adequately designed (Lucquiaud, 2010). No sources report on the flexible operation of a natural gas-fired combined cycle plant with capture, even though flexible operation of these power plants might be profitable due to their lower specific CO_2 emissions. These will decrease the CO_2 costs of venting, and the investment costs of amine storage.

This study did not consider the effect of variable use of transport and storage facilities on their costs. Variability in the supply of CO_2 will reduce the utilization rate of transport and storage, increasing the costs per tonne of CO_2 stored (Middleton and Eccles, 2013). Moreover, the use of solvent storage will increase the peak CO_2 flow that these facilities must be able to process, which may also increase transport and storage costs.

6.2.4. Model uncertainty

There are different types of uncertainty in the model:

- The modeling framework (e.g. system cost minimization) that assumes perfect competition without strategic behavior, a certain market structure (e.g. no capacity mechanism) and the limited reserve capacity modeling. This is the largest source of uncertainty but difficult to quantify for future scenarios.
- Data availability. For example the power plant capabilities and fuel contracts (e.g. the model uses generic technology assumptions as the real properties of the power plants are only available for the company that operates the plant). We estimate this uncertainty to be in the order of a few percent (~5%).
- Solver accuracy. This uncertainty is estimated at the order of <1% based on comparing model runs with different random number seeds.

From this, the impact of flexible CCS on the reserve provision is significant compared to the model uncertainty (although the impact on reserve revenues needs further investigation). In addition, the impact of flexible CCS on the electricity generation and generation revenues are of the same order of magnitude as the model uncertainty and will be affected by the (strategic) operation of the power plant. The results concerning the impact of flexible CCS are of the same order as the uncertainty.

6.3. Comparison to literature

Two types of studies have evaluated the benefits of flexible CCS: technical studies that considered fixed electricity price patterns and economic studies that focused on power system modeling. Two technical studies evaluated venting: Chalmers et al.

concluded that venting is profitable until around €18/tCO_2[17] for lower electricity prices (€37/MWh[17]), while for high electricity prices (€146/MWh[17]) the break-even point shifts to ∼€51/tCO_2[17] (2011). Haines and Davidson report the same boundary figure of €18/tCO_2[17] (2009). Studies that evaluated flexible CCS with solvent storage conclude it has the potential to increase revenues of the plants, but that this is dependent on the electricity price, carbon price and electricity price patterns (Chalmers and Gibbins, 2007; Haines and Davison, 2009; Patiño-Echeverri and Hoppock, 2012; Versteeg et al., 2013).

Three studies modeled flexible CCS operation with a power system model. Ziaii et al. modeled the optimal dispatch of the ERCOT power system of Texas with a unit commitment and dispatch model, where they observed that up to carbon prices of €11–18/tCO_2[17] venting was often applied, but that at higher prices no venting took place. When power plant operators were modeled to maximize their profits with perfect foresight, the shift occurred at carbon prices of €11–29/tCO_2[17] (Ziaii et al., 2009). Cohen et al. also optimized the profits of power plants in the ERCOT area, and found venting gradually decreased between carbon prices of €15–€44/tCO_2[17] (Cohen et al., 2011). Delarue et al. (2012) found similar break-even figures by statically assessing the feasibility of flexible CCS venting.

Only two studies quantified the effect of flexible CCS on the power system level. Cohen states that "it appears that under most conditions in ERCOT, [flexible] CO_2 capture will not have major impact on electricity prices, even when installed on half the coal-based capacity in the grid." (Cohen, 2012). Delarue et al. (2012) found that providing reserves through flexible CCS venting can reduce the costs of delivering reserves in a hypothetical simplified power system by 7% (carbon price of €20/tCO_2) and 2% (€40/tCO_2) compared to reserves being delivered by gas turbine plants. No other ways of reserve provision are considered (e.g. by conventional thermal units).

Our model outcomes are in line with previously reported values. The basic conditions for economic operation of venting are not affected by combining a technical capture unit model with a power system model. Our results show that the conclusions also apply to a European power system. Moreover, interconnectors and electricity storage do not appear to affect the operation of the flexible CCS unit, nor are feedback effects likely to occur when venting is applied by a small number of power plants. As previously reported, the operation of solvent storage is dependent on electricity price patterns. Our results show that the availability of the base power plant is important for solvent storage operation and that solvent storage can have a large impact on reserve provision. It is therefore important to simulate the operation of solvent storage with a power system model to simulate the base-plant power plant operation and electricity prices.

7. Conclusion

We investigate the benefits of two types of flexible post-combustion carbon capture, venting and amine solvent storage, by combining two simulation models. We first quantify the energy consumption of flexible operation with a capture unit model. These outcomes are used in the second model, the PLEXOS European Electricity Market Model of DNV GL, to evaluate the benefits of equipping two recently built Dutch coal-fired power plants with flexible CCS. The electricity market model minimizes the cost of power generation in the Netherlands and surrounding countries, whilst accounting for flexibility constraints and balancing reserves. By combining the two models, we account for potential feedback effects of flexible CCS on the electricity price, simulate electricity price patterns that can be expected in a future electricity system, and providing reserve capacity.

We find that the main benefit of flexible CCS for power plant operators is an increase of more than 400% in up reserve provision and a market share of 17% of the national reserves in the 2030 scenario per power plant with flexible CCS. The impact of flexible CCS on the electricity generation and wholesale revenues is limited to a small increase by up to 2%.

Flexible CCS venting seems a profitable option for power production at a carbon price of 21 €/tCO_2, but its high extra CO_2 costs make venting unattractive at higher carbon prices of >43 €/tCO_2, as also suggested in literature. Feedback effects of venting on the electricity price are limited, because the extra capacity resulting from venting is only 123 MW for a 725 MW coal fired power plant with CCS, or 0.3% of the total Dutch generation capacity in 2020 and 2030.

Flexible CCS solvent storage could be a viable option independent of the carbon price, as long as the generator operates regularly at part-load, so that solvent can be regenerated during hours of low demand. A 2-h storage capacity is sufficient in most situations, because the extra investments for more storage or regeneration capacity are larger than the extra benefits. These conclusions are in line with findings of Cohen (2012).

Flexible CCS solvent storage is economically unattractive in The Netherlands in the 2020 scenario. This changes in the 2030 scenario, when new renewable capacity pushes the generator to a mid-merit position whereby the power plant will operate more at part-load. Pay-back times are then 6 years when considering the effect of flexible CCS on electricity generation.

In addition, another benefit of flexible CCS was identified at system level: flexible CCS can provide significant share of the national up reserve requirements for the Netherlands: up to 17% in 2030. Further investigation is required to assess the impact of flexible CCS on the revenues from the reserve market. Flexible CCS hardly affects the power systems in other ways: the average electricity price could increase by 0–0.6%, and the national CO_2 emissions are slightly reduced by ∼0.1% in 2020 and 1.5–2.6% (5.5 Mt CO_2 captured with CCS) in 2030.

Combining a capture unit model with a power system model has shown to produce comparable results regarding the basic conditions for economic operation as previous studies. However, our approach also accounts for reserve provision, and it simulated the operation of the base-power plant, which is important when simulating the operation of solvent storage.

As the impact of flexible CCS on the wholesale power market is limited, it does not affect the business case of power plants with CCS. Hence, inclusion of flexible CCS in broad energy models is not necessary. Flexible CCS could be valuable on reserve markets, which can be quantified with chronological hourly simulations that include reserve markets in future studies. Overall, it is recommended to include the potential benefits of flexible capture units when deciding on the implementation of CCS.

Suggested topics for further research:

- Further research is recommended to calculate reserve prices in future energy systems for different reserve market designs, and simulate the actual generation of reserve power.
- The benefits of installing a flexible capture unit at a natural-gas combine cycle plant.

Appendix A. Performance parameters from PLEXOS model

See Table 10.

[17] Prices were converted from \$ to €$_{2010}$ with the average 2009–2011 conversion rate of \$1.37 = €1.

Table 10
Overview of performance parameters at a power plant and at power system level.

Performance parameters of coal-fired power plants with (flexible) post-combustion capture
The 'Time period' corresponds to one year (2020 or 2030) and the time step '*t*' corresponds to 1 h.

Generation of power plant[a]*: direct output from model*
Capacity factor:

$$\text{Capacity factor}\ [\%] = \frac{\text{Total power plant generation}\ [\text{GWh}]}{\text{Time period}\ [\text{h}] * \text{Maximum capacity power plant}\ [\text{GW}]}$$

Generation revenues:[a]

$$\text{Generation revenues}\ [€] = \sum_{t=1}^{\text{Time period}} \text{Generation}_t\ [\text{MWh}] * \text{Electricity price}_t [€/\text{MWh}] - \text{Fuel costs}_t [€] - CO_2\ \text{Emission costs}_t\ [€] - \text{Variable operation}\ \&\ \text{Maintenance costs}_t\ [€] - \text{Start costs}_t\ [€]$$

Reserve provision per power plant for each reserve type:

$$\text{Reserve provision}_{\text{reserve type}}\ [\text{GWh}] = \sum_{t=1}^{\text{Time period}} \text{Reserve capacity provided}_{\text{reserve type},t}\ [\text{GWh}]$$

Reserve revenues per power plant for each reserve type:

$$\text{Reserve revenues}_{\text{reserve type}}\ [€] = \sum_{t=1}^{\text{Time period}} \text{Reserve capacity provided}_{\text{reserve type},t}\ [\text{MW}] * \text{Reserve price}_{\text{reserve type},t} [€/\text{MW}]$$

Where the Reserve price is defined by the shadow price of the required reserve quantity.

Performance parameters of the power system of the Netherlands
The 'Time period' corresponds to one year (2020 or 2030) and the time step '*t*' corresponds to 1 h.

Price of electricity:[a]
The price of electricity is defined by the short-run-marginal costs of the marginal generator within that region.

Total generation costs of a country:[a]

$$\text{Total generation costs}\ [€] = \sum^{\text{All power plants in country}} \left(\sum_{t=1}^{\text{Time period}} \text{Fuel costs}_t [€] + CO_2\ \text{Emission costs}_t [€] + \text{Variable operation}\ \&\ \text{Maintenance costs}_t [€] + \text{Start costs}_t \right)$$

Total reserve provision costs for a type of reserve:

$$\text{Total reserve provision costs}_{\text{reserve type}} \sum_{t=1}^{\text{Time period}} \text{Total reserve capacity provided}_{\text{reserve type},t} [\text{MW}] * \text{reserve price}_{\text{reserve type},t} [€/\text{MW}]$$

Where the Reserve price is defined by the shadow price of the required reserve quantity.

Wind curtailment:[a]

$$\text{Wind curtailment}\ [\%] = \frac{\text{Curtailed wind generation}\ [\text{GWh}]}{\text{Potential wind generation}\ [\text{GWh}]}$$

[a] A selection of 12 representative weeks for the sensitivity analysis is based on these performance parameters. The weeks were selected such, that the performance parameters are the same as for a whole year when extrapolated with a factor (52/12). Moreover, 1 week was selected per month, including the weeks with the highest and lowest wind power production of the year.

Appendix B. Input parameters capture unit energy model

See Table 11.

Table 11
List of all inputs in the energy penalty calculation.

Variable	Number	Reference
Power plant load	%	
Amount of flexible CCS venting	% of flue gas produced by power plant at full load	
Amount of flexible CCS solvent storage	% of full load solvent flow	
Amount of flexible CCS stored solvent regeneration	% of full load solvent flow	
Power plant properties		
Maximum net capacity (without CCS)	725 MW_e	Assumption
Heat rate function	(2-degree polynomial) GJ/MWh	Assumption
CO_2 production rate	98.3 kg CO_2/GJ coal	(Eggleston et al., 2006)
Power equivalent factor	0.3 GJ_e/GJ_{th}	Assumption
General capture unit properties		
Solvent	MEA (30%-weight)	(CESAR, 2011; Wang et al., 2011)
Net loading	0.25 mol CO_2/mol absorbent	Assumption
Density of MEA solvent	300 kg/m^3	Assumption
Capture rate of capture unit	90% of CO_2 in flue gas	(NETL, 2010; CESAR, 2011)
Properties for each component of the capture unit (pumps, fans, absorber, stripper, compressor, additional solvent pumps for solvent storage)		
No. of units		Assumption
Minimum load of compressors	75%	(Chalmers and Gibbins, 2007; IEAGHG, 2012)
Energy consumption of compressor at full load	0.32 GJ/tCO_2	(CESAR, 2011)
Minimum load of absorber and stripper columns	25%	(E.ON, 2011; IEAGHG, 2012)

Table 11 (*Continued*)

Variable	Number	Reference
Efficiency penalty	11%-points	(NETL, 2010; CESAR, 2011)
Specific stripper component properties		
Heat required for heating, stripping or desorption (all at full load)	1.05 GJ_{th}/tCO_2 per process	Assumption based on (Lucquiaud and Gibbins, 2011; DNV GL, 2013)
General assumptions		
The solvent flow varies as function of capture unit load: the capture unit will be operated such that it either maintains a constant solvent liquid to flue gas ratio (*L*/*G* ratio) or a constant solvent flow at all loads.		
Parallel components in the capture unit are operated such that if there are multiple units of one component, maximum one unit runs at part-load and the other units run either at full load, at minimum load or are turned off.		

Appendix C. Data input PLEXOS modeling

See Table 12.

Table 12
Input parameters used in the model.

Power plants (DNV GL, 2013)	
• Maximum generation capacity [MW]	• Maximum up and down ramp rates [MW/min]
• Minimum stable level [MW]	• Minimum up and down time [h]
• Heat rate function (2-degree polynomial) [GJ/MWh]	• Maximum reserve provision [MW] [specified for each reserve type separately]
• Capacity rating [%]	• Start Fuel consumption [GJ/start]
• Variable operation and maintenance cost [€/MWh]	• (Minimum capacity factor [%] [for industrial CHP only])
• Start cost [€/start]	• (Markup [€/MWh] [for district heating CHP and old power plants only])
• Maintenance frequency [–]	• Mean time to repair [h]
• Forced outage rate [% of h]	• Min and max time to repair [h]
Interconnections (ENTSO-E, 2012, 2011b)	
• Maximum Flow [MW]	• Minimum flow [MW]
Regions (ENTSO-E, 2013, 2011a)	
• Load [MW]	• Availability patterns for wind and solar energy
Fuels (IEA, 2011)	
• Price [€/GJ]	• Emission price [€/kg CO_2]
• Emission production rate [kg CO_2/GJ]	
Reserves (DNV GL, 2013; ENTSO-E, 2009; TenneT, 2013)	
• Required capacity provision [MW]	• Value of reserve shortage (VoRS) [€/MW]

Appendix D. Threats and opportunities for flexible CCS

A number of factors can worsen ('threats') or improve ('opportunities') the benefits of flexible CCS with solvent storage and flexible CCS Venting, as compared to a non-flexible CCS unit (Table 13). Some of the threats are opportunities for the coal-fired power plant itself and vice versa.

Table 13
Threats and opportunities for a power plant with flexible CCS.

Threats	Opportunities
Flexible CCS solvent storage	
• More flexibility in the power system (e.g. more interconnection capacity, electricity storage, OCGTs). These can compete in providing balancing services.[a]	• An island network with limited flexibility. Flexible CCS solvent storage can capitalize on providing flexibility.[c]
• A smaller CCS energy penalty. This reduces the extra power that can be delivered by flexible CCS, but not the size of the storage facilities.[b]	• A larger reduction in the energy penalty (>70%) from using Flexible CCS, giving a larger increase in net power generation from solvent storage.
• A reserve market design where non-thermal generators can supply reserves, in particular wind power. These will compete in reserve provision, and could lower reserve prices.	• More volatile electricity prices, for example resulting from high penetration of intermittent renewable sources.[c]
• A balanced combination of fuel and CO_2 prices. The fuel and CO_2 prices influence the merit-order position of the power plant with flexible CCS solvent storage. For these plants, the optimal position in the merit order delivers a high load factor, but also periods of part-load operation to regenerate stored rich-solvent.	
Flexible CCS venting	
• A high CO_2 credit price will make venting very expensive.[b]	• A low CO_2 credit price will reduce the CO_2-credit penalty of venting.[d]
A smaller CCS energy penalty. This will increase the emissions per MWh produced through venting, and reduce the increase in net power.[b]	• A larger reduction of the CCS energy penalty when venting (e.g. 90% reduction rather than 70% of the energy penalty).

[a] These power system elements will decrease the variability in the required generation from thermal power plants, which may increase the load factors of base load plants such as coal-fired power plants with CCS.
[b] These developments will improve the business case of the base plant. They move the plant to an earlier position in the merit order, thereby increasing the load factor of the plant.
[c] An island system increases the variability of the residual load and more volatile electricity prices are an indicator of more variable residual load. More variable residual load can decrease the load factors of base load plants such as coal-fired power plants with CCS.
[d] A low CO_2 price may decrease the value of the business case of the coal-fired power plant with CCS. It moves the plant to a later position in the merit order, thereby decreasing the load factor of the plant.

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