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Profitability analysis of flexible operation of thermal power with CO_2 capture in future electricity market

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Abstract

Carbon neutrality within the electric power sector has a pivotal role for achieving net zero greenhouse gas emissions. Variable renewable energy (VRE) sourced from solar photovoltaic and wind stands for a foundation for decarbonizing electric power sector. Multiple energy system models or integrated assessment models (IAMs) assessing strategies to decarbonize the electric power sector have included low-carbon, dispatchable power sources in addition to VRE in their optimal power generation mix, indicating their economic rationality [1]. One of such dispatchable power sources is thermal power plants with carbon capture and storage (CCS). Despite the technological maturity and economic rationality of CCS, many CCS projects have failed to be implemented. The primary obstacle to CCS implementation remains its high cost and insufficient credibility of revenues [2].

For decades, CO_2 avoided cost has been the most common index for CCS [3]. Reducing CO_2 avoided cost below the carbon price might incentivize thermal power plant owners to adopt CCS. Nevertheless, as long as net profits of the power plant are negative, the final investment decision of the CCS implementation is likely to be failure. In addition, although various energy system models or IAMs have shown economically rationality of incorporating thermal power plants with CCUS into grid-level energy systems, these models do not guarantee the power plants' profitability in the electricity market. Moreover, the profitability of thermal power plants with CCS has been scarcely evaluated and reported regardless of high interest for CCS cost in this research field. According to Otsuki et al.[4], there are 13 existing energy system analyses for Japan—most of them include thermal power plants with CCS in the power generation mix—, but none of them do not evaluate the profitability of each power plant. Previous research estimated the profitability based on actual electricity prices in the electricity market at the time [5,6]. Therefore, to our knowledge, this study is one of the few attempts to examine the financial viability of thermal power plants with CCS in the future electricity market.

This study aimed to evaluate the profitability of a natural gas combined cycle (NGCC) system with CCS and clarify key factors that influence its profitability. An NGCC system can be operated with quick ramp-up/down, and its relatively low CAPEX and high OPEX are economically well-suited to couple with high VRE shares [1] in terms of the capacity factor (CF). Among CO_2 capture methods, post-combustion CO_2 capture (PCC) using amine-based aqueous solutions was chosen owing to its high level of technological readiness and applicability via either integration or as a retrofitting. The overview of the evaluation methodology is

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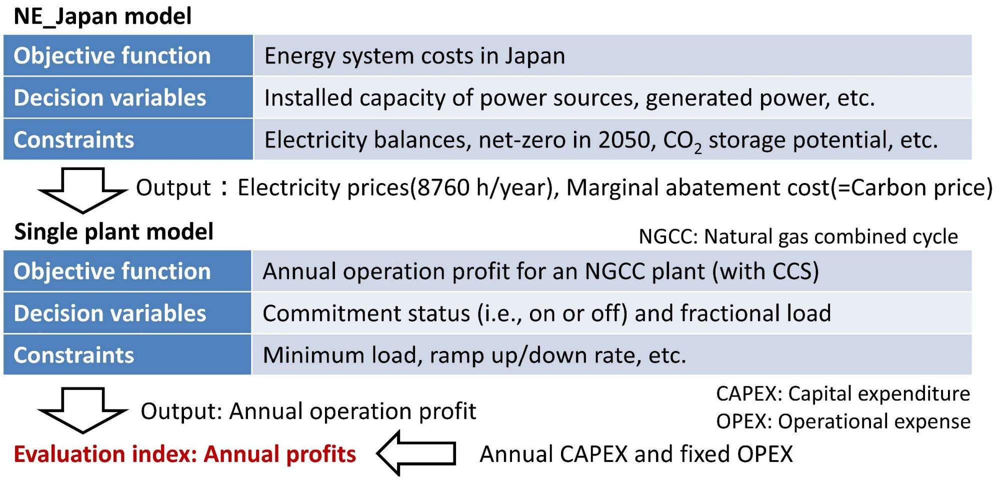

Fig. 1. Overview of profitability evaluation combining IAM and single plant model.

shown in Fig. 1. First, an energy system model in Japan developed by Otsuki et al., NE_Japan model [4], estimates the hourly, year-long electricity prices and marginal abatement cost (MAC). Then, a single plant model developed using General Algebraic Modelling (GAMS) estimates the annual operating profits of a single thermal power plant. The capital expenditure (CAPEX) and fixed operating expense (OPEX) of the thermal power plant operation are also estimated. Finally, net annual profits are obtained by subtracting CAPEX and fixed OPEX from the annual operating profits.

NE_Japan model is a linear programming model which calculates a cost-effective energy system by minimizing the discounted total system costs from 2015 to 2080. The model calculates energy balances and annual energy system costs in seven representative years: 2015, 2020, 2030, 2040, 2050, 2065, and 2080. Periods between each representative year are handled by linear interpolation. Japan is geographically divided into five regions (Hokkaido, Tohoku, Tokyo, Western Japan, and Kyushu/Okinawa) in the model to reflect renewable energy installations in each region and costs of inter-regional transmission. The reinforcement of inter-regional interconnection lines is also taken into account. Various technical and physical constraints are incorporated, such as spatial conditions of VRE or energy balance. A constraint to achieve net-zero CO_2 emissions from energy sources by 2050 is also imposed. The CO_2 storage availability for Japan is assumed to be 0, 66.6 and 200 Mt/year in 2030, 2040 and 2050, respectively. The electricity power balance is modelled in time units of 8760 hours/year to reflect the system integration costs and intermittency of VRE. The detailed calculation method and conditions of the model basically followed the previous study by Otsuki et al. [4], but specifications and costs of CO_2 capture facilities were updated based on several recent reports (e.g., [7,8]). The updated values are summarised in our recent publication [9].

The single plant model is developed using a mixed-integer linear or quadratic programming. The model optimizes the commitment status (i.e., on or off) and load factor of the components (i.e., the power plant and CO_2 capture facility) to maximize the objective variable, annual operating profits, under given input data and operational constraints. Input data includes fuel prices, cost for CO_2 transport and storage, and output of NE_Japan model (i.e., hourly, year-long electricity prices and MAC). Directly utilizing electricity price data from NE_Japan model in the single plant model optimization implies perfect foreknowledge of electricity prices throughout the study period, which is unrealistic. Hence, this study adopted a pseudo-forecasting procedure following the methodology outlined by Cohen et al. [5]. This procedure utilized historical prices to calculate a pseudo-forecasted price curve intended to approximate expected prices from day-ahead forecasts. The optimisation of plant operation mode was conducted using the pseudo-forecasted prices, and actual operating profits were subsequently calculated using the actual price data from NE_Japan model. In addition, it was assumed that the carbon price equal to the MAC calculated from NE_Japan model is imposed on the CO_2 emissions in the NGCC. Constraints include the plant's minimum load factor or ramp rate. Table 1 summarizes several scenarios considered in this study and the main assumptions in each scenario. As shown in this table, 'high fuel price scenario' and 'low capacity factor (CF) scenario' were set as pessimistic ones, while 'low specific reboiler duty (SRD) scenario' was set as an optimistic one. In the base scenario, the case without PCC ('w/o PCC') and the case with power to heat PCC ('w/ P2H-PCC') were also evaluated. The concept of P2H-PCC is detailed in our previous study [10]. Fuel prices in the future were determined based on the future perspective by IEA [11]. The detailed calculation method and conditions of the model basically followed our previous study [9,10].

For CAPEX, the total plant cost (TPC) for each facility was first calculated with referenced values of the bare erected cost (BEC). The calculated TPC values for each facility are presented in our recent publication [9]. The total overnight cost (TOC) was then calculated based on the TPC, taking into account the owner's cost, spare cost, etc. Finally, annual CAPEX was calculated by multiplying the calculated TOC by the capital recovery factor (CRF). The fixed operating costs were calculated by using the calculated TPC values, accounting for maintenance costs, labour costs, etc. The specific calculation methods for TPC, TOC, CRF, and fixed OPEX are given in the Appendix of the authors' previous study [10]. In the calculation of CRF, the interest rate and the economic life of the plant were assumed to be 0.08 and 40, respectively. The costs used in this study were converted to 2021 US dollars using the plant cost index, the exchange rate for each year and the location factor. The values calculated by NE_Japan model were also converted using the 2021 exchange rate (1 USD = ¥109.88).

Table 1. Principal assumptions in each scenario.

	Units	Value			
Scenario name		Base	High fuel price	Low CF	Low SRD
Net power output of NGCC	MW	981.1	981.1	981.1	981.1
Specific reboiler duty (SRD) of amine-based PCC	GJ/t-CO_2	2.5	2.5	2.5	1.25
Fuel price (2030/2040/2050)	USD/MMBtu	6.2/5.8/5.3	9.4/8.7/8.0	6.2/5.8/5.3	6.2/5.8/5.3
Maximum carbon capture rate	%	90	90	90	90
Maximum capacity factor of NGCC	%	85	85	42.5	85
MAC	USD/t-CO_2	See Table 2	See Table 2	See Table 2	See Table 2

Table 2 shows the MAC calculated by NE_Japan model. The MAC drastically increased as the year approached 2050, in which the constraint to achieve net-zero CO_2 emissions from energy sources was imposed. Figure 2 illustrates the annual profits and annual average electricity price at each region in Japan in 2030–2050 in the base scenario. As shown in this figure, annual profits of cases with PCC were higher than the case without PCC, and the difference was more pronounced in 2040 and 2050, when carbon prices (i.e., MAC) were higher. This result indicates that carbon prices work as an incentive for thermal power plant owners to implement CCS.

Table 2. Marginal abatement cost calculated by NE_Japan model.

Year		2030	2040	2050
Marginal abatement cost USD/t-CO_2	Base & low CF scenario	148.16	407.05	463.80
	High fuel price scenario	157.30	405.87	475.95
	Low SRD scenario	145.99	405.25	474.38

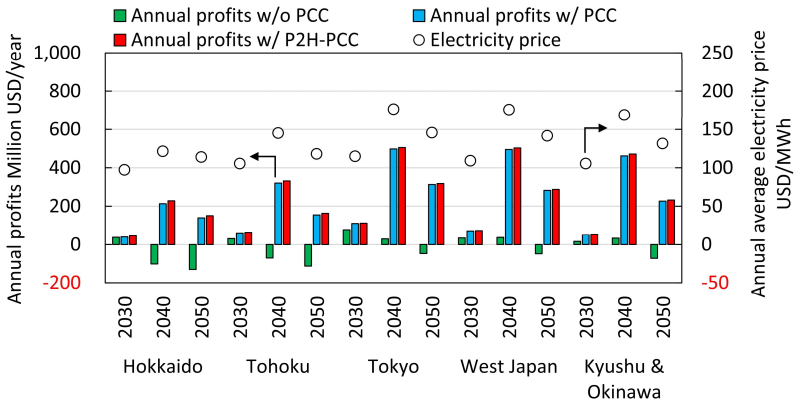

Fig. 2. Annual profits at each region in Japan in 2030–2050 obtained by the base scenario.

Figure 3 shows annual profits as a function of annual average electricity price in several scenarios, including the results shown in Fig. 2. As shown in Fig. 3, the coefficients of determination were above 0.95 except for the case without PCC, meaning that electricity price is a dominant factor in the profitability of thermal power plants with CCS. In the case without PCC, the discontinuity of the plots was supposed to be caused by drastic change in carbon price during 2030–2040, conversely supporting that the annual profits in the cases with PCC will be less influenced by carbon price. In the 'low CF scenario', annual profits drastically decreased compared to the base scenario, indicating that the maximum CF of the NGCC is also the dominant factor. Likewise, fuel price is also important (cf. 'high fuel price scenario'). On the other hand, as shown in the results of 'low SRD, w/ PCC' and 'base, w/ P2H-PCC' in Fig. 3, efficient CO_2 capture operation led to an increase in annual profits, but the impact was limited. As shown in the same figure, except for 'low CF scenario' and the case without PCC, annual profits were positive in the range of annual average electricity price above ~100 USD/MWh, which overlaps annual average electricity prices in Japan in the past five years. Moreover, the electricity prices in the future will be likely to increase owing to additional costs for realizing decarbonization. Therefore, thermal power plants with CCS are possibly economically viable in the future as long as the CF of the power plant is maintained. As such, adjusting the number of thermal power plants in a given area will be important to transition to decarbonization of the power sector.

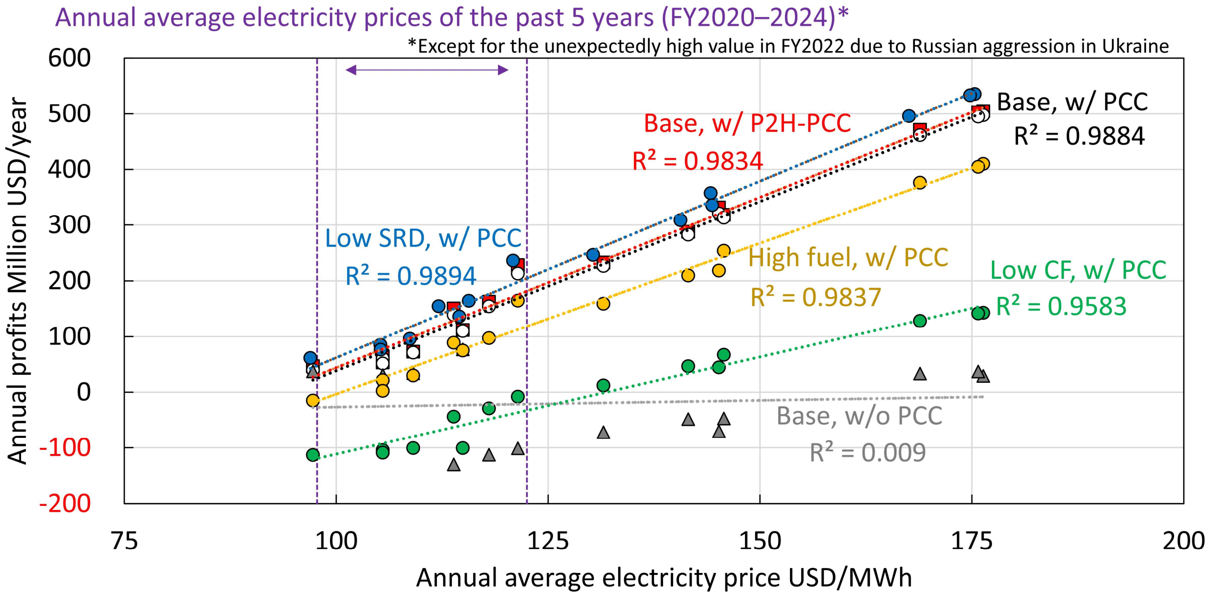

Fig.3. Annual profits as a function of annual average electricity price in each scenario.

The combination of the energy system model and single plant model in this study highlighted the key factors of the profitability of thermal power plants with CCS. Techno economic analysis of CCS should not be limited simply to evaluate the impacts of improvement of CO_2 capture performance on the cost. Investigation like this study will envisage the more realistic context of CCS implementation and help consider strategies to facilitate the implementation.

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Keywords: Amine scrubbing; Linear programming; Techno economic analysis; Chemical absorption; Energy system model; Unit commitment model

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