Chapter 41
Techno-economic Analysis on Renewable Energy via Hydrogen from Macro and Micro Scope Views

Meng Chen, Tatsuya Ookubo, Kei Hasegawa, Manabu Ihara, Takuya Oda, and Koji Tokimatsu

Abstract Since 2012, the Japanese government has widely adopted variable renewable energy (VRE), especially photovoltaics (PVs), as a result of the Feed-In-Tariff (FIT) system. However, energy storage technologies must reduce their burden on the electric power grid to make best-use of intermittent renewable power sources. Power-to-Gas (P2G), which converts surplus power from VRE to hydrogen, is a promising candidate for large-scale and long-term energy storage technology. We utilized analytical models based on actual data from micro-side research and simulation results from macro-side one. We assume that the system either uses a combination of electrolysis cells (ECs) and hydrogen fuel cells (FCs), or ECs and hydrogen co-firing using surplus power from PVs, and will be introduced around 2030 on both sides of the micro (building) and macro (power district area). On the macro side, we investigated power mix by a power planning model. We found that hydrogen fuel cells have great potential to increase local utilization of surplus power. On the micro side, we applied a cost evaluation model consisting of ECs, FCs, hydrogen storage, and PVs, with surplus power selling price as a given parameter. The model shows that total costs are lower when hydrogen is used. Additionally, when electricity selling price is volatile depending on power demand, the model predicts FC capacity expansion. We conclude that P2G has both cost competitiveness and environmental benefit, and that the combination of solar power and hydrogen is a promising technology which expands PV capacity beyond limits without combination.

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41.1 Introduction

Variable renewable energy (VRE) such as photovoltaic (PV) power has been rapidly introduced to Japan since 2012 thanks to the Feed-In-Tariff (FIT) system. However, due to the expansion of VRE, it is expected that growing surplus power from solar power may outpace the grid's power adjustment ability. To achieve a low carbon society, it is essential to expand VRE capacity beyond the current stabilized power supply system via energy storage (using batteries or hydrogen) or peak shaving.

Hydrogen-based energy storage technology is attracting attention because it offers more scale and longevity compared to batteries. Hydrogen can be used as a secondary energy source in mobile applications, as well as other applications such as hydrogen co-firing in gas fired power. In order to clarify the possibilities and challenges of hydrogen energy, we undertook a techno-economic assessment of hydrogen in both macro (i.e. co-firing in a power mix) and micro (i.e., P2G in a building with EC, FC, storage, and PV) views.

We have significant advances from previous research, e.g. The International Renewable Energy Agency's review report on hydrogen (International Renewable Energy Agency (IRENA) 2018). In Japan, Komiyama et al. (2014) wrote a review of the optimal power supply for hydrogen storage from surplus power under strict constraints on CO_2 emission. However, they targeted mainly wind power generation in Hokkaido, where wind resources are abundant. Aziz et al. (2017) developed an optimal power planning model enabling techno-economic analysis on hydrogen in both production and storage from surplus VRE in a power mix. However, they did not use actual PV data and instead use an estimate based on aggregated solar radiation data from the Japan Meteorological Agency. Additionally, as their focus was on power mix, they did not consider distributed energy including consumer-side hydrogen technologies.

These previous researches are either focused on single technology system operation (micro side) or on energy mixing but simplified calculations by using the estimated value of specific technologies (macro side). Thus, it is essential to analyze P2G technology from both macro and micro views, using actual data and establishing analysis models suitable for different implementation sizes and component technologies.

We conducted a study assuming an introduction date of 2030 of P2G technology from both macro and micro views. We used the following data: surplus power from solar power generation, EC, hydrogen tank, hydrogen FC (micro side, building level), co-fire (macro side, area level), and power demand as shown in Fig. 41.1. Sections 41.2 and 41.3 covers the macro and micro views, respectively. Moreover, we show the interlinking research between macro and micro sides in Sect. 41.4.

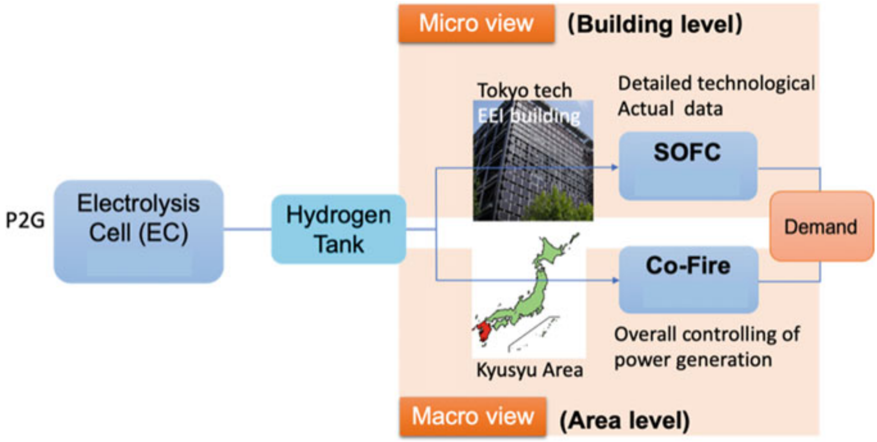


Fig. 41.1 The scope of this study

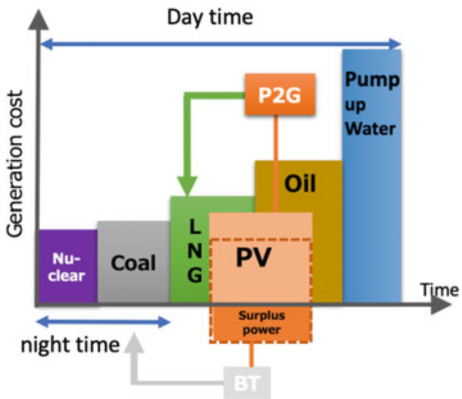
41.2 Macro Perspective

41.2.1 Methodology

The macro view analysis is based on previously developed model by Aziz et al. (2017). It is an optimal power planning model covering Kyushu area, assuming a system that produces and stores hydrogen from surplus power, in combination with thermal power plants. We expanded the power planning model to include hydrogen production equipment and storage tanks. Surplus power generation and power mix were analyzed using the power mix model, shown in Fig. 41.2.

The vertical axis represents the cost of various energy sources while the horizontal axis represents the hourly time of day. Low-cost nuclear and coal power sources are

Fig. 41.2 The power operation planning model



used both day and night whenever electricity price is low, and other energy sources such as natural gas, PV, oil, and hydro power are added only during the day time. From this analysis, we concluded that from the perspective of solving the difficulty of solar power expansion, P2G technology is beneficial. Because hydrogen can be generated (using PVs and ECs) and consumed (using hydrogen co-firing) in different place simultaneously, while batteries can only either charge or discharge, P2G technology offers an advantage since it can use surplus power during the day time as well (when electricity prices are higher). In this way, P2G enables communities to utilize zero-cost surplus power.

41.3 Result

To analyze the power mixing in Kyushu area and the characteristic of surplus power generation. Figure 41.3 models annual load duration curve in hourly basis for generation and surplus power in the Kyushu area. The horizontal axis represents larger-order of surplus power from left to right (L-shaped red curve; right vertical axis). The area graphs (blue in negative while the others such as gray in the left vertical axis) represents the amount of power generated by various energy sources.

Result shows that the time duration of surplus power generation is around 800 h/year (at a point of time to drop off zero in the red curve though actual number is higher than we expected), while the surplus power remains stable at around 300 kWh for 600 h, and 100 h afterwards, implying marginally balancing between the surplus power and demand changes. From Fig. 41.3, we conclude that as PV power increases in the future, surplus power's amount and duration will also greatly increase.

Figure 41.3 also indicates that we cannot rely on pumping hydro as a reliable energy source under various mixed renewable energies. When surplus power remains at 300 kWh, no power change is observed except from pumping hydro. This indicates that pumping hydro takes on the main role of power adjustment at 300 kWh. However,

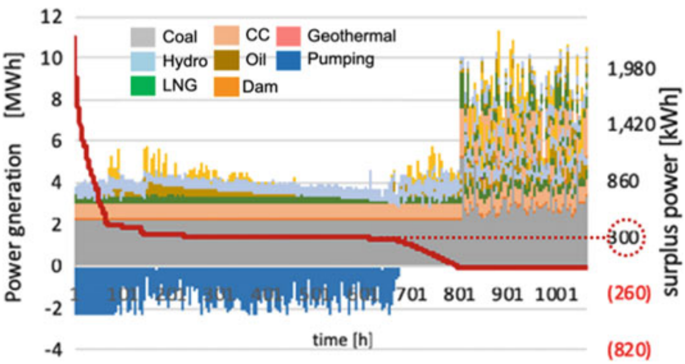


Fig. 41.3 The surplus power curve (red line, right axis) and power generation (area, left axis)

expansion of pumping hydro is limited by geographical conditions as pumping facilities can only be built on a large scale, their physical distance is typically to some extent away from other renewable energy sources unable to contribute to the power adjustment. Furthermore, when pumping hydro adjustment reaches its limit (left side of Fig. 41.3) surplus power disenables to adjust conventional power.

Our investigations in how to utilize this surplus power, focusing on distributed energy including hydrogen fuel cells as a solution.

41.4 Micro Perspective

41.4.1 Methodology

From the micro side, we used a P2G cost evaluation model, developed by Okubo et al. (Okubo et al. 2018), in a distributed energy system using PVs and hydrogen technology (the *technology system* hereafter). The model uses measured power demand and generation data from our Institute campus, and assumes an introduction year of 2030 for P2G technology, using ECs, FCs, and PV-sourced surplus power. The model also assumes a significant PV usage by 2030, backed by expected technical progress by that year.

Power market prices is important to apply this model in the real world. To this end, Apurba Sakti et al. conducted a techno-economic analysis on enhanced representations of lithium-ion batteries in power systems models and their effect on the valuation of energy arbitrage applications (Sakti et al. 2017). However, no research considers the power market in Japan using hydrogen energy storage technologies. Thus, we built an electricity selling model incorporating hydrogen energy and analyzed the operation of the technology system by using the volatile power price parametrically. Caveating that in this setting, we excluded either specific and non-existing schemes for supporting renewable powers nor extra crediting and funding mechanisms.

Selling model

Figure 41.4 shows the technology system model. In the P2G model (developed by Okubo et al. (Okubo et al. 2018), dark blue) PV, EC (including compressor), hydrogen tank, and FC determine the technology system's operation. If the amount of PV power supply exceeds demand, hydrogen is produced by EC electrolyzing the surplus power and stored in a high-pressure hydrogen tank. At this time, when the capacities of the EC and the hydrogen tank are insufficient, output control of surplus power is operated. If the PV power supply is less than the demand, the FC generates power using hydrogen to meet the power demand. If there is a shortage of power generated by the FC, then the system will purchase from grid power (Grid).

On the other hand, in the power selling model (developed by ours, in light orange), the selling time of surplus power is set (cf. the next subsection). The model assumes that whenever electricity can be sold, the technology system always sells

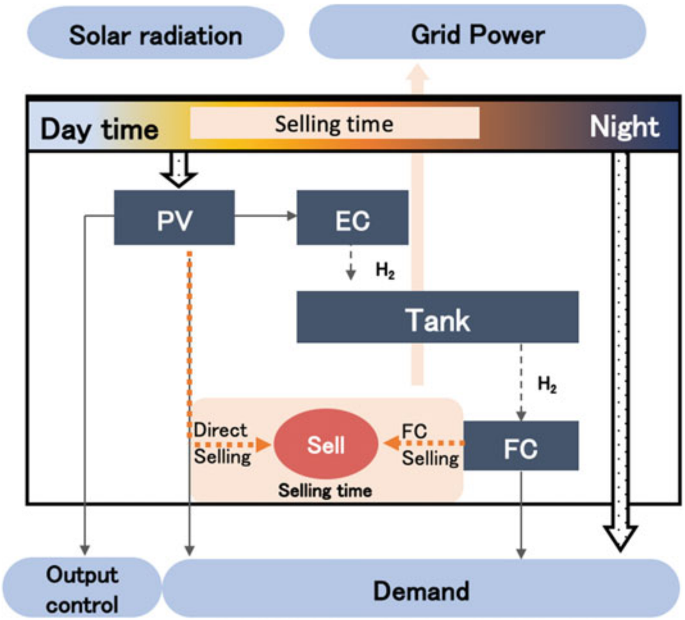


Fig. 41.4 The power selling model

FC-generated power to the grid. "FC selling" is defined as selling electricity from stored hydrogen power in FCs, and "direct selling" is defined as selling electricity from surplus power in PVs.

Selling time

Based on the curves of power supply and demand, with data sourced from the Tokyo Electric Power Company (TEPCO) [Past electricity usage data. TEPCO (2016, 2017)], we set the selling time shown in Fig. 41.5a. On the demand side shown in Fig. 41.5b, we used data from the EEI building in our Institute and determined the operational data of the technology system based on selling time. The proportion of PV in the future power supply configuration was set to 30%. It was also assumed that 30% of the power demand would be covered by PV and the rest would be covered by base-load power sources such as thermal power generation. Figure 41.5a shows a simplified power supply and demand curve for a 24-hour period by TEPCO. The base-load power generation must keep stable output in time periods during when the PV power supply capacity is lower than the power demand in selling time.

Technology system operation

By setting the selling time, we determined the technology system's operation on the demand side in a 24-hour period, as shown in Fig. 41.5b. During selling time, the power mix includes PV supply, power generation from FCs, direct selling, and FC selling. It is assumed that FC selling occurs whenever feasible. During non-selling

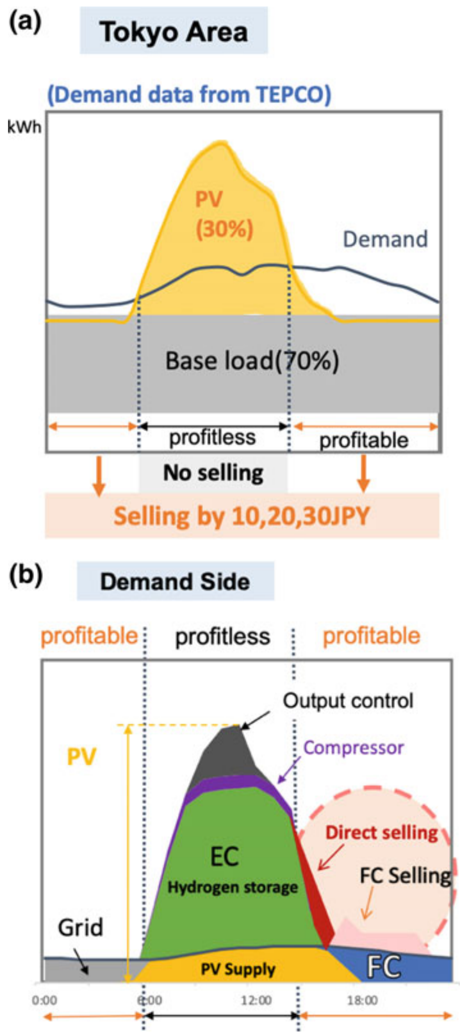


Fig. 41.5 Image of power supply in one day **a** Tokyo area (the upper image) **b** Demand side (the lower image)

time, the power configuration includes PV supply, hydrogen production from ECs, and PV output control.

Cost calculation

In this study, the combined cost of annual system cost and power sales revenue was used as the evaluation index. We present the calculation method below:

(1) **System cost**:

System cost is the total amount of initial cost and running cost. The calculation method of initial cost described as below:

(2) **Initial cost**:

a. *Introduction cost* as the product of unit price and each technology's capacity.
b. *Annual Introduction cost* is introduction cost divided by lifetime (measured in years).
c. *Initial costs* are the total sum of each technology's annual introduction cost.

(3) **Running cost**:

a. *Annual power consumption* from the operation of the technology system determined by the capacity of each technology.
b. *Running cost* is the product power purchase price and annual power consumption.

Technical parameters including unit price, lifetime, efficiency, etc. of each technology were set as shown in Table 41.1. In order to carry out the analysis while taking into consideration the future performance improvement of each technology, we estimated what each technology's performance in 2030 would be based on various references [Japan Science and Technology Agency Center low carbon society strategy (2016, 2017); Fuel Cells and Hydrogen Joint Undertaking (2014); Keizai (2017); International Energy Agency (2015); United States Department of Energy (2009); Tokyo Electric Power Company (2009)]. In this estimation, cost reduction by technological progress and learning by doing are taken into consideration. It is assumed that PV is a single crystal silicon type, EC is an alkali type, FC is a solid oxide type, and the hydrogen tank can handle 40 MPa compressed hydrogen.

41.4.2 Result

To clarify the cost composition of this model, we calculated total and detailed cost for 5 different patterns. Figure 41.6 shows the total cost and its breakdown in five different scenarios including 10JPY, 20JPY, and 30JPY in power grid price (Grid in grey bar graph), and Non-H2. The horizontal axis represents each scenario's relative cost to Grid (set at 1.0 wherein all electricity demand is satisfied by grid power). This is followed by the Non-H2 case (using PV power generation without storing surplus power) and then the selling power cases where demand is fixed regardless of the selling price (with selling power to the grid priced at 10JPY, 20JPY, and 30JPY, while purchasing power from the grid priced at a fixed in 21JPY). The bars in the graph represent relative cost for values >0, and amount sold for values <0. The red dotted line represents *total cost*, defined as annual system cost minus power selling revenue.

Comparing the scenarios of the selling prices of 20 JPY and 30 JPY with the case of Non-H2, the total cost is lower in the 20 JPY and 30 JPY scenarios. In these scenarios, although the technology system cost is high, the selling income is also high, in particular, power sold from FC accounted for the majority of the revenue.

Table 41.1 Device performance and electricity purchase price

Device	Parameter	Unit	Future value	References
PV	Unit price	JPY/kW	70,000	Japan Science and Technology Agency Center low carbon society strategy (2017)
	Lifetime	Year	30	Japan Science and Technology Agency Center low carbon society strategy (2017)
EC	Unit price	JPY/kW	70,000	Fuel Cells and Hydrogen Joint Undertaking (2014)
	Lifetime	Year	10	Fuel Cells and Hydrogen Joint Undertaking (2014)
	Efficiency	%	80	Fuel Cells and Hydrogen Joint Undertaking (2014)
FC	Unit price	JPY/kW	105,000	Japan Science and Technology Agency Center low carbon society strategy (2016)
	Lifetime	Year	20	Japan Science and Technology Agency Center low carbon society strategy (2016)
	Efficiency	%	65	Japan Science and Technology Agency Center low carbon society strategy (2016)
Tank	Unit price	JPY/L	5000	Keizai (2017)
	Lifetime	Year	20	International Energy Agency (2015)
Compressor	Unit price	JPY/ (Nm3/h)	200,000	Keizai (2017)
	Lifetime	Year	20	International Energy Agency (2015)
	Power consumption	kWh/kgH2	4	United States Department of Energy (2009)
Grid	Unit price	JPY/kWh	21	Tokyo Electric Power Company (2015)

Thus, when selling price is equal to or higher than the purchase price of electricity, hydrogen utilization technology is cost-competitive.

For each scenario, we calculated CO_2 emissions using an emission factor of 0.475 kg CO_2/L based on TEPCO 2017 (Electricity Rates and Rate Systems http://www.tepco.co.jp/en/corpinfo/illustrated/charge/overall-rates-e.html), and represent them proportionally to grid power CO_2 emissions, which is set at 100% (gray color). PV installation reduced CO_2 emissions by approximately 50%. CO_2 emissions were the lowest in the 10JPY scenario at 15.2%. This implies that CO_2 emissions can be reduced by up to 85% by using a hydrogen storage technology system.

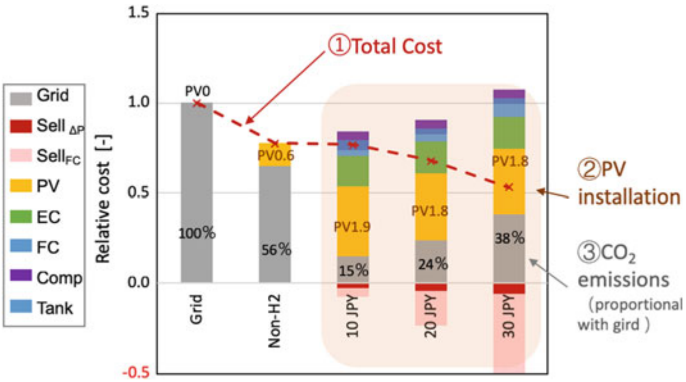


Fig. 41.6 Total cost and details of scenarios

41.5 Macro and Micro Perspectives

The above contents analyze the role of renewable use of hydrogen from micro and macro viewpoints. Combining these two views, we developed a grid-coordinated distributed smart energy system realistically for hydrogen technology usage in 2030 wherein fully deregulated power market. We use volatized selling price here instead of fixed price and redefined the selling time in the Sect. 41.3.

41.5.1 Methodology

The *actual demand* (dotted yellow line) is defined as the amount of demand without PV supply. Based on actual demand, we redefined the selling time shown in Fig. 41.7. We also revised the model from using a fixed price to using a volatile price. We calculated the volatile price based on historical actual demand using the electricity price curve. For simplicity, we ignored the grid-based adjustment cost by setting the annual minimum demand on the grid to the actual annual minimum demand of TEPCO in 2016, (the minimum power generation value on 2016, means that in this amount, it doesn't require gird adjustment control) (Fig. 41.7, orange line).

Figure 41.8 shows fuel cost lines for the Kyushu (left side) and Tokyo (right side) areas. The Kyushu fuel cost line is sourced from (Aziz et al. 2017), which is a linear regression of Kyushu Electric Power Company's (Kyushu Power Co.'s) fuel cost versus demand (Aziz et al. 2017). We created the Tokyo fuel cost curve for the TEPCO area as described below.

The fuel cost line in Fig. 41.8 shows the cost range of Kyushu Power Co. is 2~10JPY. We used TEPCO's actual minimum and maximum demand from 2016–2017 and assumed that TEPCO's maximum and minimum fuel costs are the same as

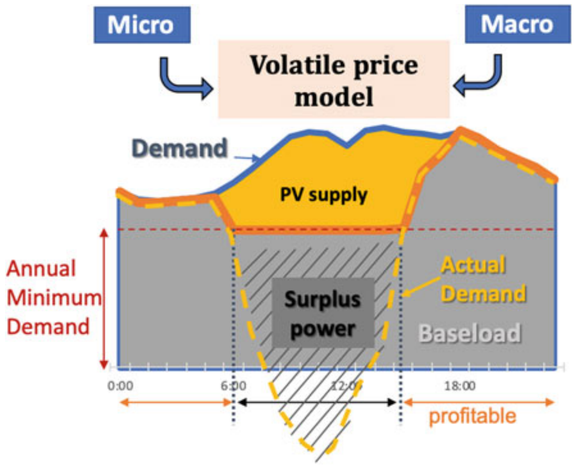


Fig. 41.7 The volatile price model

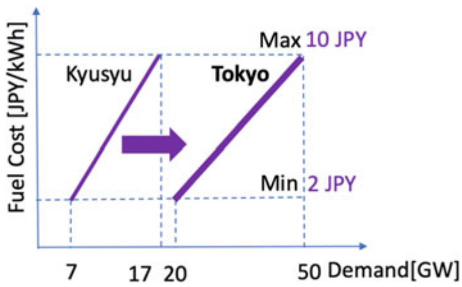


Fig. 41.8 The method of fuel cost curve in accordance with demand capacity

Kyushu Power Co.'s because the equipment used by both companies has the same power generation efficiency at peak and minimum load.

By substituting volatile prices for fixed prices in the micro-view electricity selling model presented in Sect. 41.3, we calculated the *demand-based hourly volatile price*, which is the sum of fuel cost, capital cost, and power company profit (Fig. 41.9).

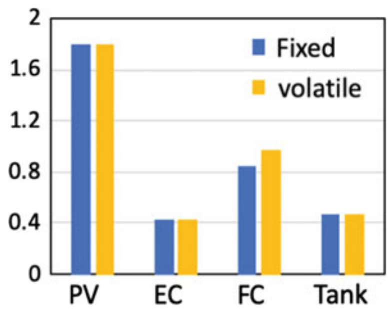


Fig. 41.9 Installation ratio of P2G device

Using this updated model, we optimized the system's total cost. The installation rate of EC, FC, and hydrogen tank were optimized at a PV installation rate of 1.8, which balances purchase and sales amounts. Although the installation rates of EC and Tank are almost the same between fixed and various models at minimum cost, the installation rate of FC increases. Our explanation for this is that when fixed prices are changed to volatile ones, FC plays a role in adjusting variable cost. This implies FC installation expansion is required to mitigate demand fluctuations in volatile price.

41.5.2 Future Consideration

The daily PV supply and power demand inevitably depend on weather conditions and other factors. Therefore, analyzing FC selling methods that can respond to these external factors is a logical next step. The following two FC selling methods should be considered.

1. Instead of selling at the full capacity, we should set a sales-volume ratio; i.e. selling at a high ratio in high prices, selling in a controlled manner in moderate prices, and not selling in low prices.
2. Since the shape of the price fluctuation curve doesn't change significantly daily, we should simulate FC sales accordingly. Specifically, sets sales to be suppressed when prices rise and to be sold in large quantities when prices fall.

41.6 Summary

We evaluated a hydrogen energy technology system from both macro and micro views. It is assumed that the technology system, which includes PV, EC and FC or hydrogen co-firing, will be introduced around 2030 on both micro (building) and macro (power district) levels.

On the macro side, power mix sourced from various energy technologies was investigated. We found that hydrogen fuel cells have great potential to increase the utilization of surplus power locally. On the micro side, a renewable energy system using hydrogen storage technology considering power sold by FCs was created. After evaluating this system, we clarified that incorporating the hydrogen system decreases costs. Furthermore, after substituting consumer demand-based volatile price for fixed price in the model, it became clear that FC installation expansion will be necessary.

We conclude that the hydrogen-based technology system has demonstrated cost merit and environmental benefit, and that solar power could see widespread usage in the future when combined with hydrogen storage.

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