# Economics and Roles of e-gas towards City Gas Decarbonization

by

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**Abstract**

The role of e-gas exists in how to transport and deliver synthesized methane as carrier of hydrogen to the users while avoiding the risk of stranded assets of the existing city gas network. At the same time, the fact that the existing gas network can relatively easily accommodate renewable energy converted to e-gas should be emphasized. This is exactly a concept of Energy System Integration. This study revealed through simulation model composed from power generation mix module and city gas demand module that if 300GW of wind and 300GW of solar PV can be introduced in Japan, the e-gas production cost can compete with the e-gas production from imported hydrogen. Although cost reduction of renewable energy should be achieved to realize the Energy System Integration through e-gas, it should be remembered that the domestic e-gas production and utilization can bring about advantages in improvement in resiliency and energy security. On the other hand, e-gas import that is able to reduce international shipping cost by using the existing LNG supply chain is also expected to be an option, though this option was out of scope of this study. Meanwhile, in order for e-gas to be introduced into the existing city gas network, there still remains complicated discussions on the attribution of $CO_2$ emission reduction. By the time the transition period is passed, recommended strategies for e-gas producers would be to secure their own $CO_2$ resources such as biomass or DAC to avoid the complicated and political debates.

## 1. Introduction

Besides biogas whose potential is limited compared to city gas demand volume, hydrogen and hydrogen-based methane (e-gas) are expected as options to decarbonize city gas through blending. Although hydrogen blending into the existing city gas network is drawing much attention mainly in Europe, it has been pointed out that hydrogen blending poses various technological and institutional issues, such as safety, calorific adjustment in consumers equipment and change in metering.[1)] On top of these issues, decarbonization impact of city gas gained from hydrogen blending is limited due to lower calorific value of hydrogen. In order to avoid these challenges, e-gas blending into the city gas network is also being addressed mainly in Japan, as e-gas is the major feedstock of city gas. The existing study[2)] shows that e-gas offers an economic advantage over hydrogen that needs new infrastructure. The other study[3)] also reveals an economic advantage of CHPs (combined heat and power) that uses e-gas over batteries as a measure of grid flexibility required when large-scale of variable renewable energy are connected to the power grid. These studies put the focus on domestic production of e-gas synthesized from hydrogen from domestic renewable energy and recycled $CO_2$ with a background that the gas network is increasingly drawing much attention as provider of capacity for energy storage and flexibility to mitigate intermittency of variable renewables through producing and accommodating either hydrogen or e-gas from surplus renewable electricity. This concept is called the Energy System Integration through Power to Gas that is expected as an enabler of decarbonization of the whole energy system through renewable energy.

On the other hand, there is another option for e-gas procurement; producing from imported hydrogen. This study compares the economics of e-gas production from domestic renewable energy-derived hydrogen and e-gas production from imported hydrogen. Based on the comparison, the conditions that the e-gas production from domestic renewable energy-derived hydrogen can be advantageous would be revealed.

In addition to the above comparative economic analysis of e-gas, one of the most crucial institutional issues that may hamper the promotion of e-gas will be addressed. Due to the facts that the process from production to utilization of e-gas overstrides two technological fields, hydrogen and CCU (Carbon Capture and Utilization), and that $CO_2$ is inevitably reemitted upon utilization of e-gas, interpretation of the attribution of $CO_2$ emission reduction from e-gas would cause controversy. This study will discuss how rational institutions for promotion of e-gas should be structured.

## 2. Economics of e-gas Production

### 2.1 Methodology for e-gas production from domestic renewable energy

The simulation model developed in the existing study[3)] is employed to figure out the economics of e-gas production from domestic renewable energy-derived hydrogen. This model is composed of power generation mix module and city gas demand module (Figure 1). The power generation mix module simulates hourly surplus electricity to be used for hydrogen production followed by e-gas production. The city gas module identifies the hourly e-gas volume that can be blended into city gas network. Scenarios are set for capacity (GW) of variable renewable energy (solar photovoltaics and wind), and city gas calorie tolerance that specifies acceptable e-gas volume. For the sake of simplicity, it is assumed that Japan is a single node. The $CO_2$ to be used for e-gas production comes from gas-fired power generation and biomass power generation, which are identified through the power generation mix module, and also from intensive large-scale industries[2)], assuming that only concentratedly emitted $CO_2$ can be used for producing e-gas.

The hourly e-gas producible volume is identified by surplus electricity scale, but not all producible e-gas is able to be blended into the city gas network. The hourly e-gas volume that is blended is determined by the magnitude relation between the hourly producible e-gas and the acceptable e-gas blending ratio (vol%) set as scenario. If the producible e-gas is larger than the acceptable capacity at a certain time, the e-gas is charged and stored in the existing gas storage facility then discharged for the later use. The capacity of e-gas production facility (electrolyzer, methanation, $CO_2$ capture) is identified based on the correlation of the hourly producible e-gas volume from surplus electricity and the acceptable blending volume taking into account the blending via storage, by carrying out multiple case simulation with e-gas production capacity as a variable.

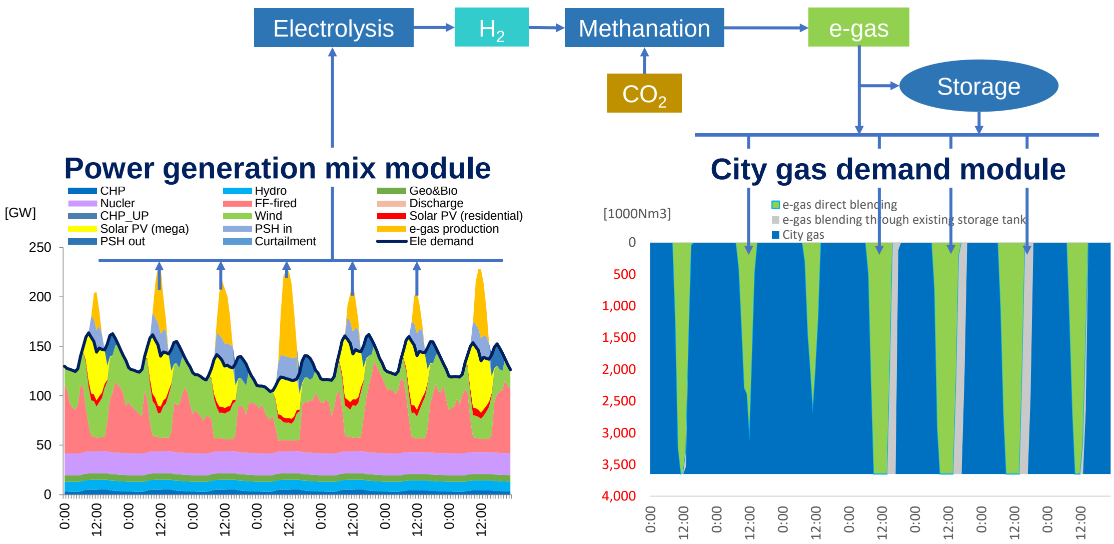


**Figure 1 Simulation Structure**

### 2.2 Assumption and scenarios

(1) Electricity demand, power generation capacity and city gas demand

Taking into account possible long-term electrification trends and electricity saving, it is assumed that electricity demand will increase by 10% from the current level to 1,040 TWh. The must-run power generation from nuclear, hydro and geothermal + biomass is assumed to be 190 TWh, 87 TWh and 58 TWh, respectively, based on the long-term vision discussed at the committee of the Government of Japan. No pumped-storage hydro will be added. Thermal power generation is assumed to be completely LNG-fired from a long-term perspective. The capacity of solar PV and wind is set as scenario (see below). The city gas demand is assumed to be 35.1 billion $m^3$ ($45MJ/m^3$ equivalent) based on the demand of the larger gas utilities in FY2016. The demand varies monthly, but the hourly demand within each month is assumed to be constant due to lack of data. Figure 2 shows the hourly electricity and city gas demand through the year.

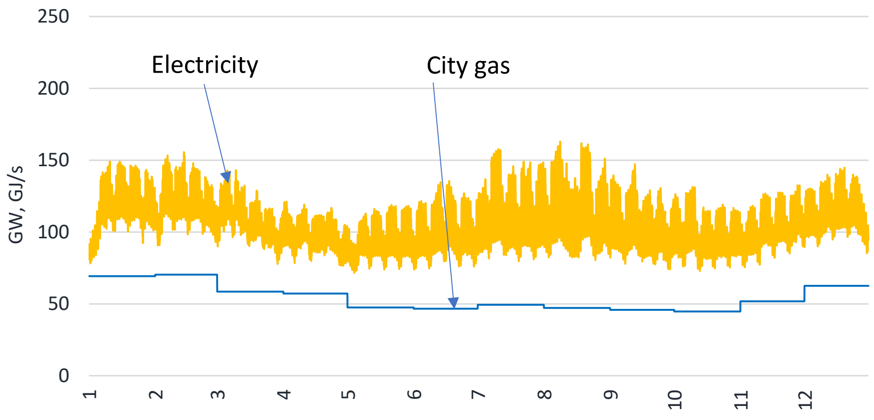


**Figure 2 Hourly Demand Profile of Electricity and City Gas**

(2) Performance and cost of technologies

The technological performances for electrolysis, methanation and carbon capture are shown in Table 1 [2),3),4),5)]. The pressure of e-gas is assumed to be 1MPa as the pressure of city gas storage facilities is usually 0.85MPa. The scale of energy storage in the city gas infrastructure is estimated using the geometric volume and pressure of gas holders and pipelines[6)] (Table 2). While there is room for debate on whether pipelines can be used as storage facilities, as city gas does not require the instantaneous supply-demand balancing as electricity does, the pipelines are also assumed to have storage capacity. Table 3 shows the assumptions of facility costs that are used in the economic analysis [2),3),4),5)].

LNG price is assumed to be 50,000 yen/ton (0.92 yen/MJ) based on trends in recent years. The procurement cost of domestic renewable energy and imported hydrogen is assumed to be JPY5/kWh, JPY30/$Nm^3$, respectively.

**Table 1 Assumptions for Technical Performance**

| | | |
|---|---|---|
| Electrolysis + Methanation | 18.0 | kWh/$Nm^3$-$CH_4$ |
| Auxiliary | 0.32 | kWh/$Nm^3$-$CH_4$ |
| Electricity for $CO_2$ capture | 0.02 | kWh/$Nm^3$-$CH_4$ |
| Compressor (1MPa) | 0.074 | kWh/$Nm^3$-$CH_4$ |
| Total | **18.42** | kWh/$Nm^3$-$CH_4$ |
| Heat for $CO_2$ capture | 3,549 | kJ/$Nm^3$-$CH_4$ |
| | (1,800) | MJ/t-$CO_2$ |
| $CO_2$ capture ratio | 90% | |
| Boiler efficiency | 80% | |

**Table 2 Storage Capacity of City Gas Infrastructure**

| | | |
|---|---|---|
| Gas tank | 34 | million $Nm^3$-$CH_4$ |
| Pipeline | 38 | million $Nm^3$-$CH_4$ |
| Total | 72 | million $Nm^3$-$CH_4$ |

**Table 3 Assumptions for CAPEX**

| | | |
|---|---|---|
| Electrolyzer | 215 | 1000JPY/($Nm^3$-$H_2$/h) |
| Methanation | 500 | 1000JPY/($Nm^3$-$CH_4$/h) |
| e-gas production | 1360 | 1000JPY/($Nm^3$-$CH_4$/h) |
| CCU ($CO_2$ capture and boiler) | 134 | million JPY/(t-$CO_2$/h) |
| | 0.26 | million JPY/($Nm^3$-$CH_4$/h) |

(3) Scenario

Based on the current cumulative capacity and the future perspectives, the power generation capacity of solar PV is assumed to be from 100GW to 300GW and that of the wind power to be from 30 GW to 300 GW. 15 scenarios are established by combination of solar PV and wind power (Table 4). The acceptable e-gas blending ration is set by the acceptable calorific value of city gas (Table 5).

It should be noted that the acceptable blending ratio is hourly ratio and that the annual blended ratio yielded as a result of the simulation is not equal to the hourly ratio, must be smaller than the hourly ratio. With regard to the e-gas produced from imported hydrogen, the blended ratio is equal to the hourly acceptable blending ratio.

**Table 4 Variable Renewable Deployment Scenario**

| | | Solar PV | | |
|---|---|---|---|---|
| | | 100 GW | 200 GW | 300GW |
| Wind | 30 GW | | | |
| | 50 GW | | | |
| | 100 GW | | 15 scenarios | |
| | 200 GW | | | |
| | 300 GW | | | |

**Table 5 e-gas Blending Scenario**

| Acceptable calorific value of city gas (MJ/m$^3$) | Acceptable e-gas blending ratio (vol%) |
|---|---|
| 39.8 | 100.0% |
| 41.0 | 76.9% |
| 42.0 | 57.7% |
| 43.0 | 38.5% |
| 44.0 | 19.2% |
| 45.0 | 0% |

**2.3 Results**

Figure 3 shows the capacity factor of e-gas production from domestic renewable energy with acceptable e-gas blending ratio as a variable, yielded from the simulation. The individual line represents the scenario of variable renewable energy deployment. The larger the scale of variable renewable energy deployment, the higher the capacity factor, due to the fact that the larger-scale of renewable energy deployment produces larger-scale surplus electricity. The higher the acceptable e-gas blending ratio, the lower the capacity factor, because larger capacity of e-gas production is required to meet the maximum acceptable level of e-gas. For example, the e-gas production capacity factor is 3%~6% in case of “50GW of wind + 200GW of solar PV”, 12%~18% in case of “100GW of wind + 300GW of solar PV” and 29%~39% in case of “300GW of wind + 300GW of solar PV”.

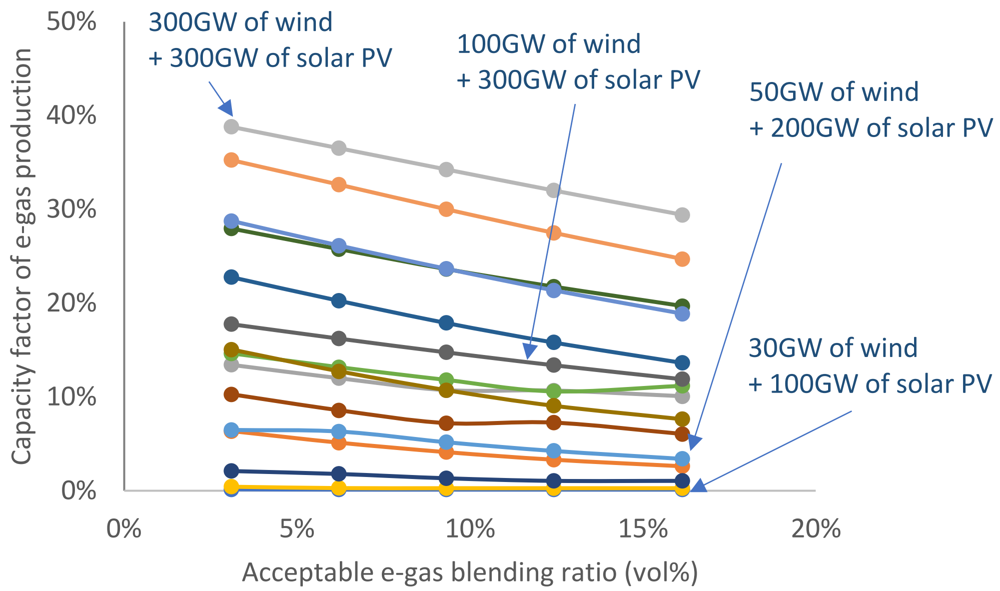


**Figure 3 Capacity Factor of e-gas Production (Domestic Renewable Energy)**

Figure 4 compares e-gas production cost from domestic renewable energy and from imported hydrogen. The area chart shows e-gas production cost from domestic renewable energy with the capacity factor of e-gas production facility (electrolysis, methanation and carbon capture) as a variable (horizontal axis). The cost is composed from CAPEX & OPEX and electricity procurement cost with unit price assumed to be JPY5/kWh. The horizontal solid line represents the e-gas production cost from imported hydrogen with procurement cost (CIF) including liquified hydrogen storage facility assumed to be JPY30/$Nm^3$, which is the target of the Government of Japan at around 2030. According to the bar chart showing the breakdown of the cost of e-gas production from imported hydrogen, the procurement cost of imported hydrogen is dominant element. The intersection of the area chart and the horizontal solid line indicates the required capacity factor of the e-gas production from domestic renewable energy in order for the e-gas production from domestic renewable energy to be competitive with e-gas production from imported hydrogen, which is about 27%.

The range of the capacity factor for several renewable energy deployment scenarios is shown by yellow shading. This means that if renewable energy deploys up to "300 GW of wind + 300GW of solar PV", the e-gas production from domestic renewable energy is able to compete with e-gas production from imported hydrogen. This is due to higher capacity factor of electrolyzer and methanation. The higher capacity factor derives from two factors. One of the factors is that increasing amount of variable renewable energy causes large scale surplus electricity. The other one is that capacity of electrolyzer and methanation can be minimized as determined by e-gas acceptability by city gas.

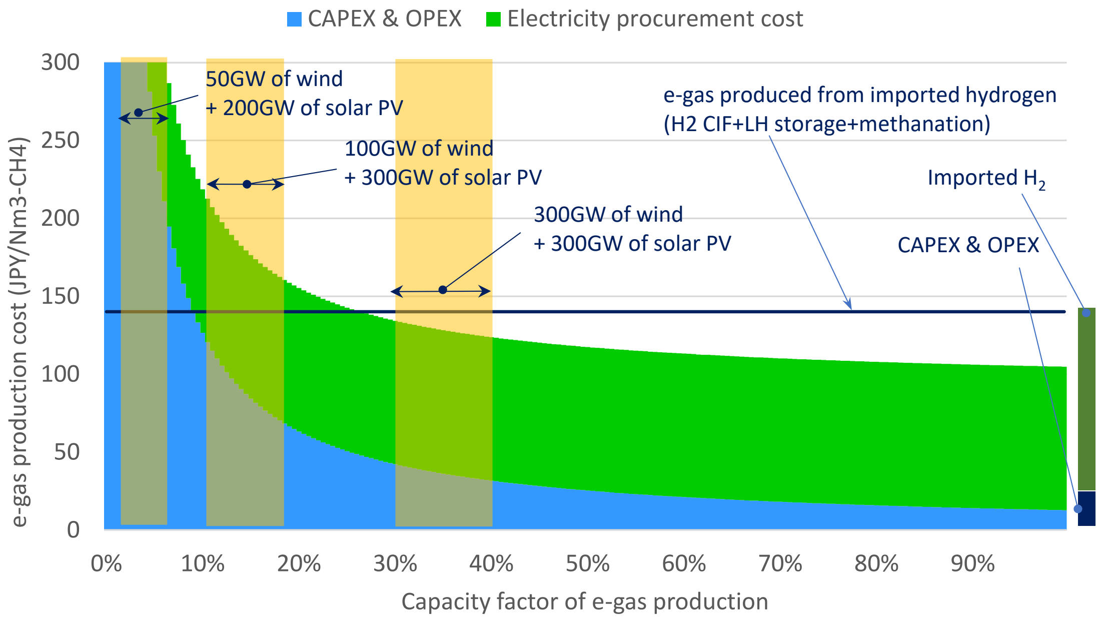


**Figure 4 e-gas Production Cost (Domestic Renewable and Imported Hydrogen)**

If large-scale deployment of variable renewable energy can be realized, the fact that the existing gas network can relatively easily accommodate renewable energy converted to e-gas should be emphasized. This is exactly a concept of Energy System Integration, which aims large-scale deployment of variable renewable energy by expanding capacity to accommodate variable renewable energy through integrating power sector and the other sectors like city gas.

Nevertheless, it should be noted that the results are highly dependent on the assumptions mainly on electricity procurement cost and imported hydrogen cost that have still uncertainty. Whether the renewable electricity procurement cost will be able to reach to JPY5/kWh should be carefully examined. In addition, as renewable energy potential is presumably limited in Japan, the rational possibility of deployment to the level of "300GW of wind and 300GW of solar PV" should also be examined. If large-scale renewable energy deployment cannot be realized, e-gas production from imported hydrogen is required. However, at the same time, whether the procurement cost of imported hydrogen will be able to go down to JPY30/Nm$^3$ should also be carefully examined.

On the other hand, e-gas import that is able to reduce international shipping cost by using the existing LNG supply chain is also expected to be an option.

## 3. Discussions on Institutions Required for e-gas Promotion

### 3.1 Revisiting the mechanism of e-gas

(1) Fundamental impact is not affected by the origin of $CO_2$ in producing and using e-gas

Based on the scientific clarification, the mechanism of e-gas is that; e-gas is synthesized from hydrogen and $CO_2$ that is captured from certain facilities. As the $CO_2$ that is emitted through the use (combustion) of e-gas is offset with the captured $CO_2$, the substitution of natural gas through the use of e-gas is the $CO_2$ reduction impact. In other words, as $CO_2$ is only captured, utilized, and re-emitted, the use of e-gas is essentially identical with the use of hydrogen. Accordingly, $CO_2$ emissions from e-gas are not problematic (Figure 5).

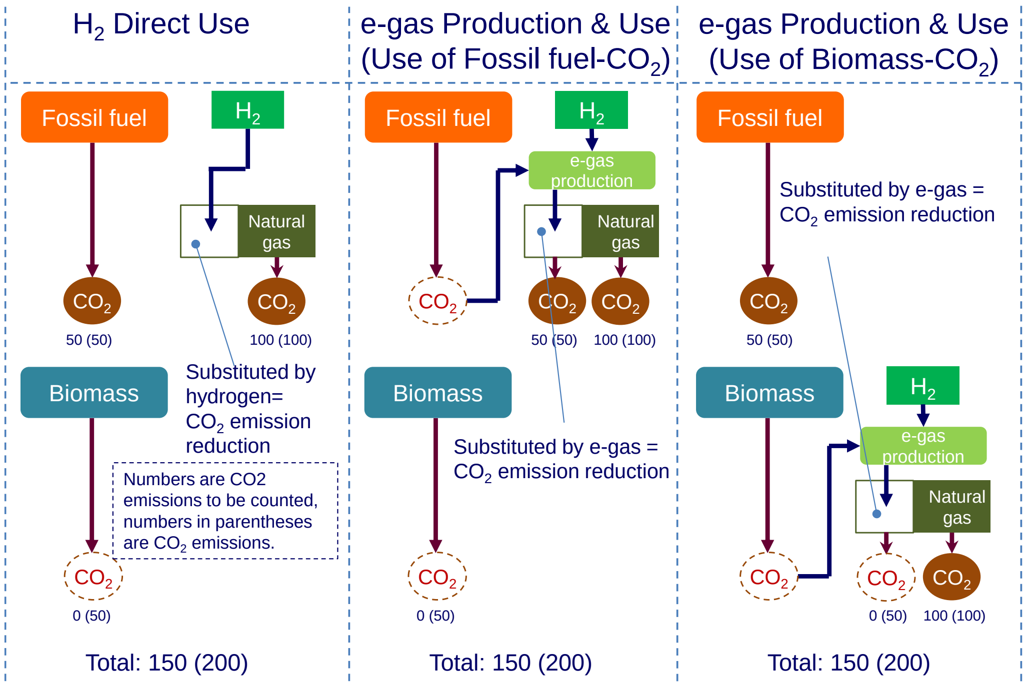


**Figure 5 No Fundamental Difference in $CO_2$ Sources for e-gas Production[7)]**

Therefore, CO2 emission reduction impact of e-gas is identical regardless of the origin of $CO_2$, either fossil fuel or biomass or atmosphere. The reason why e-gas is expected lies in the fact that e-gas is able to utilize the existing infrastructure with no or minimum modification (Figure 6). In order for hydrogen to be transported and directly used in the consumers, new infrastructure should be established. In other word, this is the unique and sole reason for e-gas.

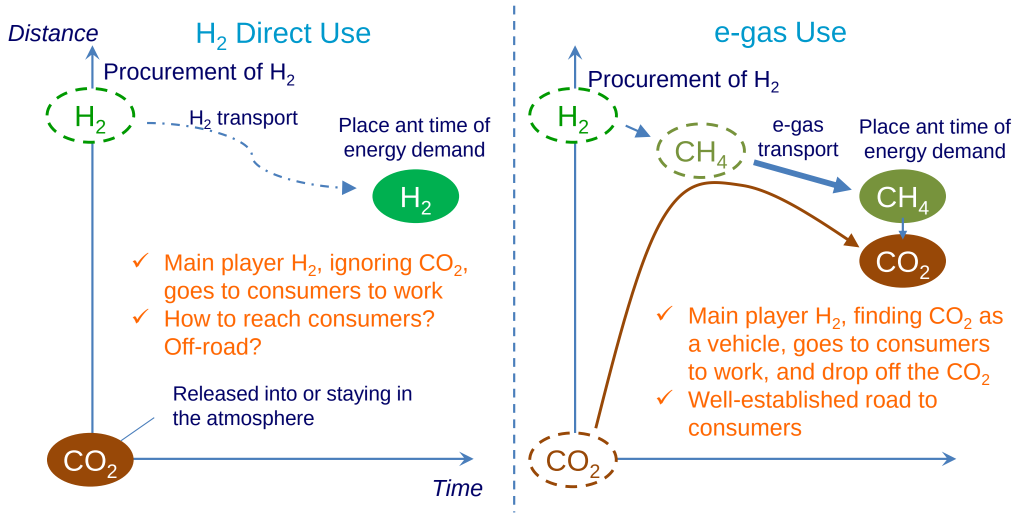


**Figure 6 Why e-gas? Advantages in Using Existing Infrastructure**

(2) e-gas is theoretically identical with hydrogen, should NOT be categorized in CCU

Looking at this aspect from different point of view, it is obvious that the CCU process involved in the e-gas production and utilization does not have any $CO_2$ emission reduction impact as the $CO_2$ is eventually released into the atmosphere. Only hydrogen contributes to the $CO_2$ emission reduction. This is the reason why e-gas/fuel is called "Hydrogen-based Fuels" or "Hydrogen Derivatives", not "Carbon Recycle Fuels". e-gas/fuel should be categorized in hydrogen (Figure 7). Categorizing e-gas/fuel into "Carbon Recycle Fuels" frequently leads to misunderstanding that e-gas/fuel is able to reduce $CO_2$ emission "by CCU or carbon recycling". Correctly, e-gas/fuel is able to reduce $CO_2$ emission "by hydrogen". It is needless to say that the expression "producing fuels from $CO_2$" is definitely incorrect. Hydrogen per se is fuel, but $CO_2$ cannot be a fuel.

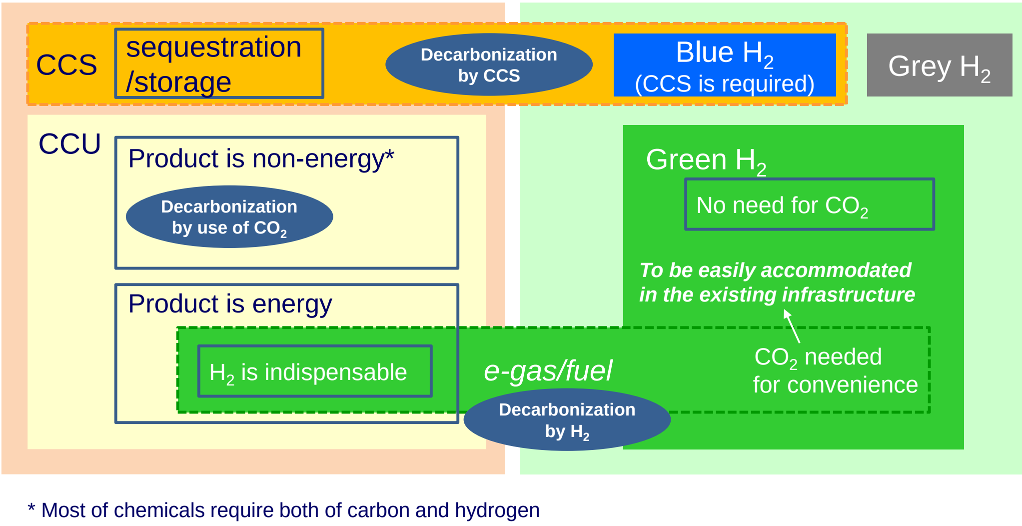


**Figure 7 Categorization of CCS, CCU, Hydrogen and e-gas**[8)]

### 3.2 Discussions on attribution of $CO_2$ emission reduction

The clarification above can be interpreted that the $CO_2$ emitter-and-provider cannot have any $CO_2$ emission reduction, while all of the $CO_2$ emission reduction impact can be attributable to the e-gas producer/user. Meanwhile, there might be an interpretation that e-gas cannot be realized without cooperation from $CO_2$ emitter-and-provider and so that the $CO_2$ emission reduction impact should be shared between $CO_2$ emitter-and-provider and e-gas producer/user. However, it should be noted that institutions established based on this interpretation may lead to lock-in of fossil fuel use for only providing $CO_2$ for producing e-gas, in spite of the fact that there is no $CO_2$ emission reduction impact from the CCU in the process of e-gas production and utilization. In addition, there is no theoretical evidence for allocating $CO_2$ emission reduction impact between $CO_2$ emitter-and-provider and e-gas producer/user. The $CO_2$ emission reduction should be totally attributed to the e-gas producers/users (Figure 8).

According to these discussions, it is highly recommended that e-gas producers should have their own $CO_2$ resources, either biomass or DAC (Direct Air Capture) facilities, in order to avoid these complicated discussions on attribution of $CO_2$ emission reduction.

However, in case of import of e-gas, international rules or bilateral agreement for $CO_2$ emission accountings should be established.

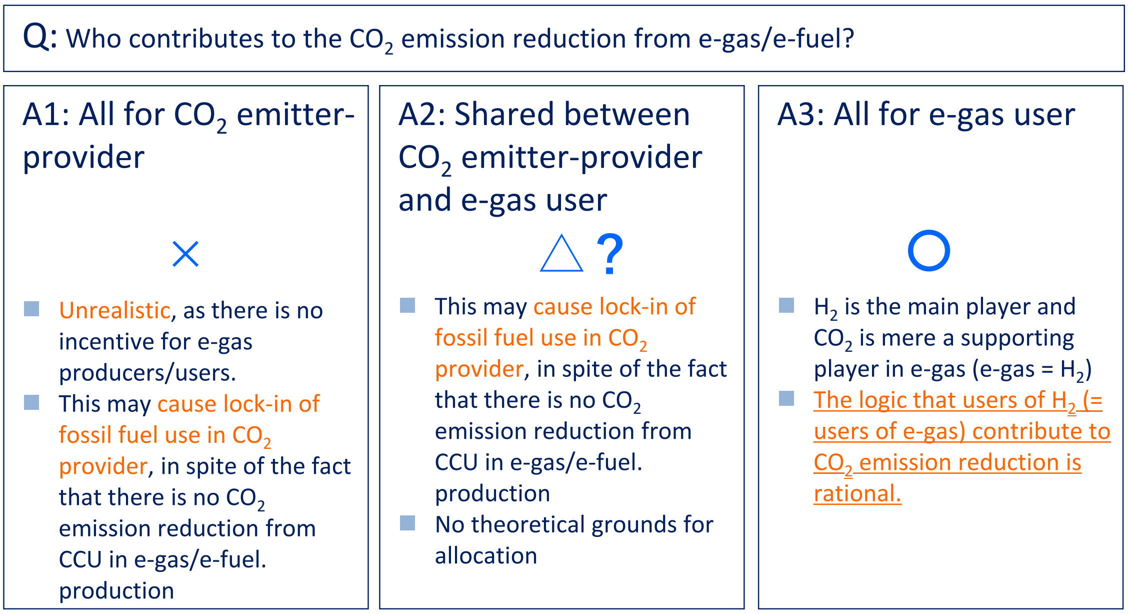


**Figure 8 $CO_2$ Emission Reduction Attribution of e-gas**

## 4. Summary

The role of e-gas exists in how to transport and deliver hydrogen to the users while avoiding stranded assets of the existing city gas network. At the same time, the fact that the existing gas network can relatively easily accommodate renewable energy converted to e-gas should be emphasized. This is exactly a concept of Energy System Integration. This study revealed that if 300GW of wind and 300GW of solar PV can be introduced in Japan, the e-gas production cost can compete with the e-gas production from imported hydrogen. Although cost reduction of renewable energy should be achieved to realize the Energy System Integration through e-gas, it should be remembered that the domestic e-gas production and utilization can bring about advantages in improvement in resiliency and energy security. On the other hand, e-gas import that is able to reduce international shipping cost by using the existing LNG supply chain is also expected to be an option, though this option was out of scope of this study.

Meanwhile, in order for e-gas to be introduced into the existing city gas network, there still remains complicated discussions on the attribution of $CO_2$ emission reduction. By the time the transition period is passed, recommended strategies for e-gas producers would be to secure their own $CO_2$ resources such as biomass or DAC to avoid the complicated and political debates.

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