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Economic and environmental evaluation of hydrogen carriers traveling from overseas production to final demand in Japan

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Summary

Various hydrogen carriers, including liquified hydrogen, methylcyclohexane (MCH), ammonia, and synthetic methane will be an option for importing hydrogen. The economic and environmental performance of these hydrogen carriers varies depending on the domestic supply chain, including end-use (electricity or heat), in addition to the international supply chain. In this study, we evaluated the economic performance and the carbon footprint of hydrogen carriers traveling from overseas production sites to final demand sites in Japan assuming a long-term perspective beyond 2030. We obtained the following conclusions:

- In terms of cost for power generation application, synthetic methane (innovative technology)-firing is the lowest among carriers derived from renewable electricity, followed by ammonia cracked hydrogen-firing. Among carriers derived from natural gas (abated by carbon capture and storage: CCS), synthetic methane (existing technology)-firing and ammonia cracked hydrogen-firing are the least expensive. In terms of the cost of industrial heating application, which is significantly affected by domestic transportation, synthetic methane is the least expensive option due to the fact that synthetic methane can use existing gas pipelines and other infrastructure.
- With regard to the carbon footprint of the entire supply chain for the power generation application, synthetic methane is the smallest among carriers derived from renewable electricity, while ammonia is the smallest among carriers derived from natural gas (with CCS). For the industrial heating application, synthetic methane using existing gas pipelines has the smallest carbon footprint because truck transportation can be avoided through the utilization of existing city gas infrastructure. On the other hand, the carbon footprint of MCH is the largest due to the high fuel consumption involved in international transportation and dehydrogenation. Synthetic methane and ammonia can maintain their economic advantage due to the smaller carbon footprint of their entire supply chains, even after counting in a certain level of carbon price. It should be noted although the carbon footprint of synthetic methane will vary depending on how international rules are formed regarding the attribution of CO_2 emissions

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from synthetic fuel and gas combustion, the CO_2 emissions from synthetic methane combustion are assumed to belong to the original CO_2 emitters in this analysis.

This analysis is based primarily on the assumptions made in the 2019 International Energy Agency (IEA) report “The Future of Hydrogen,” and does not take into account the effects of recent soaring resource prices, high commodity prices, and the depreciation of the Japanese yen.

A certain amount of clean fuels such as hydrogen and its derivatives is required for decarbonization. The cost structure of hydrogen carriers employed for importing clean fuels from overseas is roughly divided into hydrogen carrier synthesis and transportation. The cost of hydrogen carrier synthesis is higher for carriers derived from renewable electricity than for those derived from natural gas (with CCS). However, it is necessary to reduce the capital cost of hydrogen carrier synthesis in both cases, and procuring inexpensive renewable electricity is critical for carriers derived from renewable electricity.

With regard to transportation costs, MCH, ammonia, and synthetic methane, which can utilize existing infrastructure and commercial transportation technologies, are considerably less expensive than liquefied hydrogen, which requires new transportation technologies. However, dehydrogenation of MCH and cracking of ammonia into hydrogen are factors that increase cost, and the advantageous options are direct use of ammonia and synthetic methane, which do not require conversion into hydrogen. If domestic transportation is included, the cost of synthetic methane is the lowest because the use of existing city gas infrastructure avoids the use of trucks and the construction of hydrogen pipelines, which would be cost-increasing factors.

In other words, in order to achieve a cost-effective supply of clean fuel from overseas to Japan, it is necessary to secure inexpensive feedstocks, reduce the cost of hydrogen carrier synthesis through technological innovation, and squeeze the transportation cost by utilizing existing infrastructure and transportation technologies that are already in commercial use.

Introduction

Various hydrogen carriers, including liquified hydrogen, methylcyclohexane (MCH), ammonia, and synthetic methane will be an option for importing hydrogen. The Institute of Energy Economics, Japan (IEEJ) has conducted evaluations and studies on international hydrogen supply chains connecting hydrogen producing countries and Japan, represented by the “Study on the Economics of the Green Hydrogen International Supply Chain” [1]. However, when considering the actual application of hydrogen, it is necessary to carry out an evaluation that includes domestic customers in Japan. As indicated by the establishment of a price difference support scheme (contract for difference) to promote the introduction of hydrogen and the establishment of a CO_2 emissions intensity standard for the hydrogen production mentioned in the Basic Hydrogen Strategy revised in June 2023, the economic efficiency and carbon footprint are important axes for evaluation.

In this report, we evaluated the economics and carbon footprint of hydrogen in a manner that includes not only international supply chains but also domestic supply chains assuming domestic consumers in Japan.

1. Economic evaluation of international supply chains

This study first estimates the costs involved in international transportation and import (including reconversion costs) of hydrogen produced at suitable overseas locations. As shown in Section 1.1, multiple supply chains are assumed, and the cost per unit of supply is calculated by dividing the annual cost of each supply chain by the annual supply volume (Equation 1-1). In calculating the annual cost, capital costs are converted to an annual cost using a capital recovery factor.

$$\mathrm{JPY/Nm^3\text{-}H_2} = \frac{\text{Annual cost (JPY/year)}}{\text{Annual supply (Nm}^3\text{-H}_2\text{/year)}}$$
$$= \frac{\text{Hydrogen or carrier production cost} + \text{Port storage cost} + \text{Transportation cost} + \text{Reconversion cost}}{\text{Total supply}} \quad (1\text{-}1)$$

1.1. Supply chain options

Figure 1-1 summarizes the supply chain options. A total of 14 cases were assumed, depending on the hydrogen production process and domestic and international transportation carriers. Two types of hydrogen production processes are considered: water electrolysis using renewable electricity (cases 1 to 9) and natural gas reforming abated by CCS (cases 10 to 14). Synthetic methane, liquefied hydrogen, MCH, and ammonia are assumed as carriers for international transportation, while synthetic methane, hydrogen, and ammonia are assumed as carriers for domestic distribution after unloading in Japan. The boundary for cost estimation is set to the gate before the distribution by these domestic carriers (Figure 1-2 and Figure 1-3). The cost of infrastructure for distribution to consumers and the cost of energy-consuming equipment of the customers are not included. Furthermore, Cases 8 and 9, as references, estimate the cost of producing synthetic methane from hydrogen derived from domestic renewable electricity.

Case	Production site and feedstock	International H_2 carrier	Domestic delivery H_2 carrier
1 Overseas SCH_4 (innov)	Overseas renewable electricity	$LSCH_4$	SCH_4
2 Overseas SCH_4 (conv)			
3 Overseas LH_2		LH_2	H_2
4 Overseas MCH		MCH	
5 Overseas NH_3 (split into H_2)		LNH_3	
6 Overseas NH_3 (direct use)			LNH_3
7 Overseas MCH + Domestic methanation		MCH	SCH_4
8 Domestic SCH_4 (innov)	Domestic renewable electricity	none	
9 Domestic SCH_4 (conv)			
10 Overseas SCH_4 (conv)	Overseas natural gas abated by CCS	$LSCH_4$	SCH_4
11 Overseas LH_2		LH_2	H_2
12 Overseas MCH		MCH	
13 Overseas NH_3 (split into H_2)		LNH_3	
14 Overseas NH_3 (direct use)			LNH_3

Figure 1-1 Cases for International Supply Chain

Note: SCH_4 = Synthetic methane; $LSCH_4$ = Liquified Synthetic methane; LH_2 = Liquified Hydrogen; MCH = methylcyclohexane; LNH_3 = Liquified ammonia; innov = innovative, conv = conventional.

An overview of each case is described below. Firstly, in Cases 1, 2, and 10, synthetic methane is produced and liquefied in the overseas production country and transported internationally. Conventional technology (Sabatier reaction) and innovative technology were considered for the methane synthesis technology. Specifically, the conventional methane synthesis technology is combined with water electrolysis located upstream, while the innovative technology is a more efficient direct methane synthesis technology that integrates water electrolysis and methane synthesis. After the liquefied methane gas is unloaded in Japan, it is distributed to consumers as synthetic methane. In Cases 3 and 11, liquefied hydrogen is transported from the producing country to Japan. After being unloaded in Japan, it is vaporized into hydrogen for domestic distribution. Cases 4, 7, and 12 involve international transportation of MCH and dehydrogenation to extract hydrogen after unloading in Japan. Cases 4 and 12 are based on the assumption that domestic distribution is made in the form of hydrogen, while Case 7 is based on the assumption that methane synthesis is performed at the unloading site. As shown in Section 1.3, Case 4 was the least expensive among Cases 3 to 5, in which hydrogen derived from overseas renewable energy is transported in the form of carriers and converted back to hydrogen after unloading in Japan. Based on these results, we decided in this study to set Case 7, in which synthetic methane, the main component of city gas, is produced from hydrogen transported by MCH. Cases 5, 6, 13 and 14 are cases in which liquefied ammonia is used as a carrier for international transport. Cases 5 and 13 involve cracking ammonia into hydrogen after unloading in Japan, while Cases 6 and 14 involve the direct use of imported ammonia (excluding the cost of ammonia cracking).

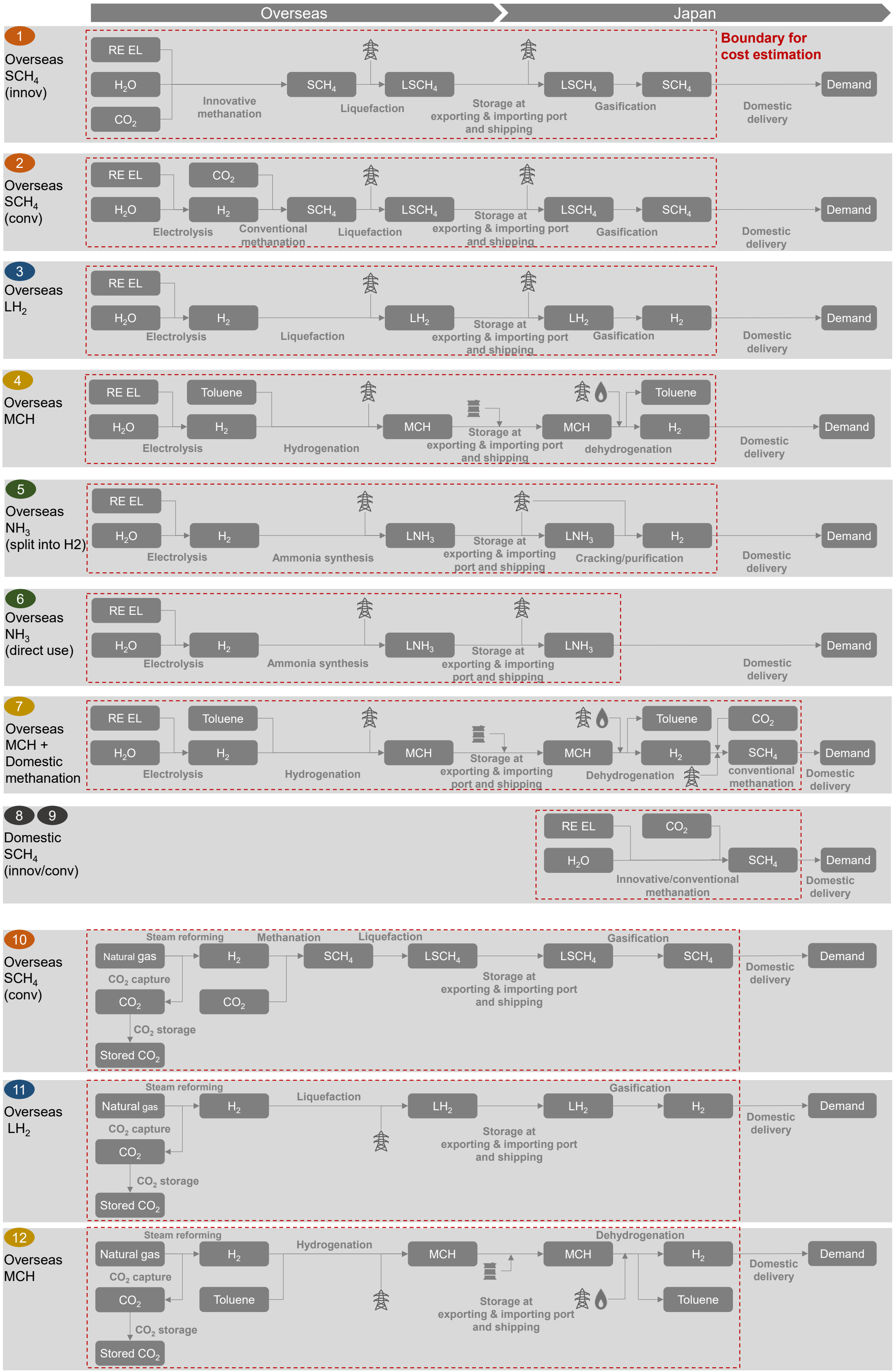

Figure 1-2 Description of International Supply Chains

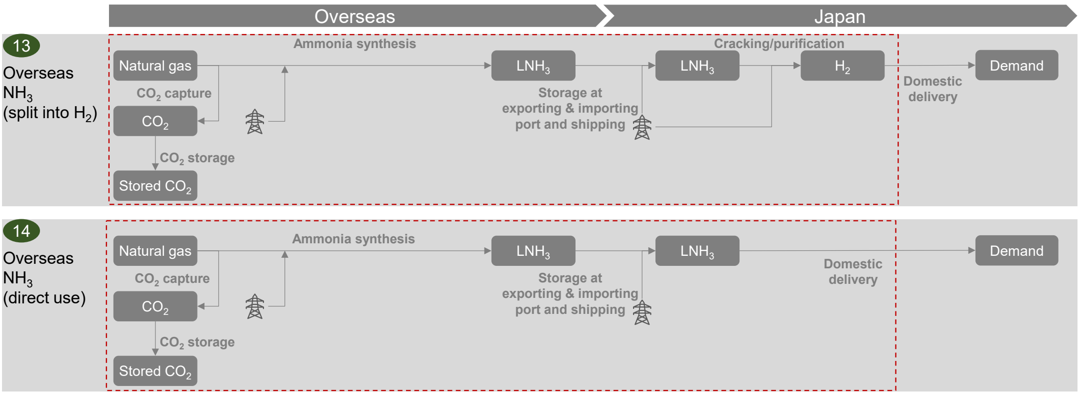

Figure 1-3 Description of International Supply Chains (cont.)

Note that Case 10, in which synthetic methane is produced from natural gas-derived hydrogen abated by CCS, needs to be considered from the viewpoint of overall system efficiency. In Case 10, the procedure is that natural gas is separated into hydrogen and CO_2 in the overseas production country, and then the CO_2 captured from other CO_2 sources and hydrogen are synthesized into methane. Compared to this case, it would be more efficient in the overall system to transport natural gas directly to Japan, capture CO_2 from the CO_2 sources, and store CO_2 directly (Figure 1-4, "Separated gas chain and CCS system"). In other words, the "Separated gas chain and CCS system" (Figure 1-4) keeps the overall system CO_2 emissions and energy amount transport to Japan at the same level as Case 10, but is able to eliminate the natural gas reforming, CO_2 capture (required for methane synthesis), and methane synthesis processes. Needless to say, in the "separation system," as the natural gas chain and CCS are separated, there is no environmental benefit to the natural gas chain. However, from the perspective of overall optimization, it is important to note that there may be a way to maintain the natural gas chain and to achieve net decarbonization through measures like credit transfers.

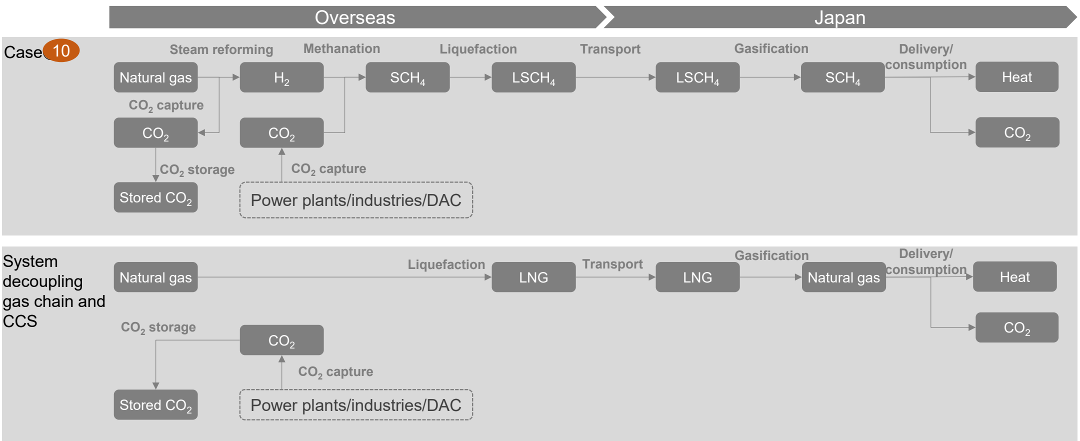

Figure 1-4 Comparison of Case⑩ and "System decoupling gas chain and CCS"

1.2. Major assumptions

The analysis methodologies are based on [2]. The scale of transportation volume for each supply chain is assumed to be about 260 ktH_2/year (about 2.9 billion Nm^3-H_2/year, or 100,000 Nm^3-CH_4/h in synthetic methane equivalent) based on the "The Future of Hydrogen" by the IEA [3]. When supplied as synthetic methane, this scale corresponds to about 2% of Japan's annual city gas consumption. The year of analysis is not specifically identified, but the parameters are set assuming a long-term perspective beyond 2030.

Overseas producing countries are assumed to be in the Middle East, which has relatively excellent renewable energy conditions and abundant natural gas resources. The unit price of renewable electricity is set at 2.5 cents/kWh and the capacity factor at 29%, based on the IEA's report [3]. This renewable energy is assumed to be a hybrid of solar photovoltaic and wind power. The capacity factor for the water electrolysis and the innovative methane synthesis (Case 1) are assumed to be identical to that of renewable energy electricity. The natural gas price is assumed to be 3.4 USD/MMBtu (the world's lowest long-term price level in the IEA's report [3]). The domestic renewable energy assumptions for Cases 8 and 9 are also based on the same IEA report (the unit price of renewable electricity is 6.3 cents/kWh, and the capacity factor is 19%). The hydrogen production (water electrolysis and natural gas reforming with CCS), liquefied hydrogen production and transportation, MCH production and transportation, and ammonia production and transportation are also based on the IEA's report [3], while methane synthesis, methane gas liquefaction, and liquefied methane gas transportation and receiving facilities are based on interviews with companies working on these technologies. For the factors related to hydrogen production, the capital cost for water electrolysis is set at 450 USD/kW and the efficiency (based on lower heating value) at 74%. The capital cost for natural gas reforming with CO_2 capture is set at 1,280 USD/kW_{H2} and efficiency at 69%, with an additional 20 USD/tCO_2 for CO_2 transportation to the storage site and storage. See Table 1-1 for the description and parameters for the conversion of hydrogen to each carrier and its transport and receiving at the port. The discount rate for this analysis is assumed to be 8%, following the IEA [3]. In addition, since the assumptions in the IEA's report [3] are presented in 2017 USD prices, this analysis is also based on 2017 prices, and the exchange rate is assumed to be 113 yen/USD. Note that some of the factors related to methane synthesis and liquefied methane gas transportation are changed from [2], so the results are slightly different from those in [2]. Also, note that only supply chain costs are evaluated in this estimation, and the environmental aspects (such as CO_2 emissions) were not included in this estimation. The CO_2 emission intensity of each supply chain is discussed in Chapter 3.

Table 1-1 Process and Parameters for International Supply Chains

(a) Overseas synthetic methane chain (Case①, ②, ⑩)

Process/technology	Description	Utilities	Major parameters
Innovative methanation	Technology that integrates electrolysis and methanation, which does not need independent electrolysis and gains high conversion efficiency. The capacity factor of the innovative methanation is identical with that of renewable electricity.	Electricity (renewables)	CAPEX and life OPEX Capacity factor Water unit consumption CO_2 unit consumption Electricity unit consumption
Conventional methanation	Sabatier reaction. When electrolytic hydrogen is used, the capacity factor of electrolysis and conventional methanation is identical with that of renewable electricity. When natural gas steam reforming hydrogen is used, the capacity factor of Sabatier reaction is assumed to be 95%.	Electricity (Renewable electricity is used if the hydrogen is produced from renewable electricity. If hydrogen is produced from natural gas, grid electricity is used.)	CAPEX and life OPEX BOP electricity consumption
Liquefaction	Existing liquefaction is used (efficiency is 50%).	Electricity (grid)	Electricity unit consumption Maintenance cost
Storage at exporting & importing port and shipping	Existing infrastructure is used (storage tank, loading, LNG tanker). The fuels required for shipping are supplied from cargo $LSCH_4$, reducing the arriving amount of $LSCH_4$.	Electricity (grid)	Electricity unit consumption Boil-off rate Port entry interval Maintenance cost Loading/unloading days Boil-off rate at loading/unloading Nautical speed of tanker

(b) Overseas liquified hydrogen chain (Case③, ⑪)

Process/technology	Description	Utilities	Major parameters
Liquefaction	The capacity factor of H_2 liquefier is assumed to be 90%.	Electricity (grid)	Facility scale CAPEX Life OPEX Capacity factor Electricity unit consumption
Storage at exporting port	Liquefied H_2 storage tank.	Electricity (grid)	Facility scale CAPEX Life OPEX Boil-off rate Capacity factor Electricity unit consumption
Shipping	Liquified H_2 tanker. The fuels required for shipping are supplied from boil-off H_2 and cargo LH_2 if boil-off is not sufficient, reducing the arriving amount of LH_2.	none	Facility scale CAPEX Life Nautical speed of tanker OPEX Fuel consumption Boil-off rate Flush-rate Loading/unloading days
Storage at importing port and gasification	Liquefied H_2 storage tank.	Electricity (grid)	Storage days Others are same as exporting port

(c) Overseas MCH chain (Case④, ⑦, ⑫)

Process/technology	Description	Utilities	Major parameters
Hydrogenation	Hydrogenation of toluene. Initial and refill costs are included. Heat is supplied from hydrogen. The capacity factor is assumed to be 90%.	Electricity (grid) Natural gas	Toluene price Toluene initial requirement and refill Facility scale CAPEX Life OPEX Capacity factor Electricity unit consumption Heat unit consumption
Storage at exporting port	Existing petroleum storage tanks are used.	Electricity (grid)	OPEX Electricity unit consumption
Shipping	Existing oil tankers are used. The fuels required for shipping are supplied by fuel oil.	none	Nautical speed of tanker OPEX Fuel consumption Fuel price Loading/unloading days
Storage at importing port	Existing petroleum storage tanks are used.	Electricity (grid)	Same as exporting port
Dehydrogenation	Dehydrogenation of MCH. The heat required is supplied from natural gas. PSA is used for purifying hydrogen.	Electricity (grid) Natural gas	Facility scale CAPEX Electricity unit consumption Heat unit consumption OPEX H_2 recovery rate (dehydrogenation and PSA)

Table 1-2 Process and Parameters for International Supply Chains (cont.)

(d) Overseas ammonia chain (Case⑤, ⑥, ⑬, ⑭)

Process/technology	Description	Utilities	Major parameters
Synthesis	If using renewable electricity, electrolysis and ammonia synthesis is regarded to be not-integrated; the capacity factor of electrolysis is identical with that of renewable electricity, while the capacity factor of ammonia synthesis is assumed to be 95%. If using natural gas, the process is integrated, the capacity factor is assumed to be 95%. The hydrogen is abated by CCS.	Electricity (grid)	CAPEX Life Capacity factor OPEX Unit consumption of electricity and natural gas CO_2 coefficient
Storage at exporting port	Liquified ammonia storage tank.	Electricity (grid)	Facility scale CAPEX Life Capacity factor OPEX Electricity consumption
Shipping	Liquified ammonia tanker. The fuels required for shipping are supplied from cargo LNH_3, reducing the arriving amount of LNH_3.	none	Facility scale CAPEX Life Nautical speed of tanker OPEX Loading/unloading days Fuel consumption
Storage at importing port	Liquified ammonia storage tank.	Electricity (grid)	Storage days Others are same as exporting port
Cracking	Ammonia is split into hydrogen, with required heat supplied from natural gas. PSA is used to purify hydrogen.	Electricity (grid) Natural gas	Facility scale CAPEX Electricity unit consumption Heat unit consumption OPEX H_2 recovery rate (cracking and PSA)

1.3. Analysis results

Figure 1-5 shows the cost analysis results for international supply chains. As an overall trend, it can be inferred that hydrogen carriers derived from natural gas with CCS (Cases 10 to 14) are less expensive than those derived from renewable electricity (Cases 1 to 9). The least expensive of the cases is Case 14 (direct use of ammonia derived from natural gas with CCS), which is at the level of JPY 21/Nm^3-H_2. The Japanese government has set targets for "hydrogen supply cost" (CIF cost) of JPY 30/Nm^3-H_2 in 2030 and JPY 20/Nm^3-H_2 in 2050, and for ammonia at the upper JPY 10 level/Nm^3-H_2 in 2030 in the Basic Hydrogen Strategy [4]. In Case 14, the cost equivalent to CIF (excluding "import port and reconversion" in Figure 1-4) was estimated to be 20 yen/Nm^3-H_2, which is close to the Japanese government target. The technologies for ammonia production from natural gas and ammonia transportation are matured and commercialized. On the other hand, Case 13, which involves cracking ammonia into hydrogen after unloading, resulted in worse economic performance throughout the supply chain compared to direct combustion. This is due to the cost of supplying heat to the ammonia cracking process and to losses in hydrogen purification.

Next to overseas ammonia derived from natural gas with CCS (direct use), overseas synthetic methane (Case 10) derived from natural gas with CCS was evaluated as a favorable option (JPY 25/Nm^3-H_2). Like ammonia, synthetic methane has a significant advantage in that the technologies related to transportation (liquefaction, transportation, receiving base, storage tanks, etc.) are commercially established. Furthermore, in the case of synthetic methane, existing infrastructure can be utilized, which is also regarded to contribute to cost reduction. As pointed out in Figure 1-4, Case 10 needs to be considered from the perspective of overall system efficiency. However, the utilization of hydrogen derived from natural gas may be useful in the short to medium term as a foothold for the future expansion of synthetic methane derived from renewable electricity. For example, one of the technological challenges for methane synthesis is scaling up, and if natural gas-derived hydrogen can be used for demonstration purposes to achieve a larger scale at an early stage, it could contribute to the expansion of the synthetic methane supply chain derived from renewable electricity in the long term.

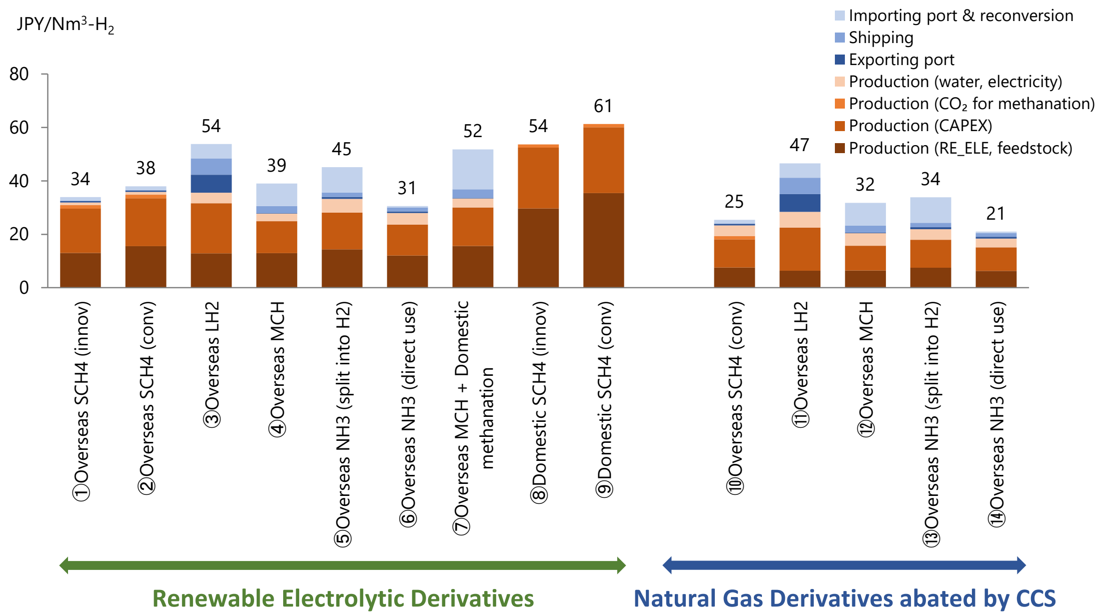

Figure 1-5 Cost Comparison among International Supply Chains

Note: "Production" includes costs associated with the production of hydrogen carriers (water electrolysis, methane synthesis, hydrogen liquefaction, hydrogenation reaction, and ammonia synthesis).

Note: The estimates in the IEEJ's report [1], which aim to compare the economics of multiple hydrogen supply chains connecting Japan and other countries (but do not include synthetic methane), and the estimates of this study show almost the same results. The slight difference stems from differences in assumptions for water electrolysis capital costs, energy prices, and other such aspects.

For hydrogen derived from renewable electricity in Cases 1 through 9, overseas ammonia (direct use) in Case 6 is the least expensive option, followed by overseas synthetic methane in Cases 1 and 2. It can be said that overseas ammonia (direct use) and overseas synthetic methane are important options for hydrogen carriers.

A breakdown of the cost structure shows that the production costs of hydrogen carriers account for the greater part of all supply chains. In particular, hydrogen carrier production costs dominate in case of ammonia (direct use) and synthetic methane, which have relatively low transportation and post-unloading costs. More specifically, the capital costs of water electrolysis and hydrogen carrier production (for example methane synthesis) and the procurement costs of feedstock energy (renewable electricity and natural gas) are the major cost factors. In order to improve the economics of each supply chain, in addition to technological development, securing “concessions” of inexpensive renewable energy with high capacity factors (such as securing land) as well as stable and inexpensive natural gas procurement in the producing country is extremely important for realizing each supply chain.

MCH was the most competitive option in the supply chains with conversion back to hydrogen after unloading (Cases 3 to 5 and 11 to 13), but was evaluated as more expensive than ammonia (direct use) and synthetic methane. The cost structure of MCH includes a relatively high heat supply cost for the dehydrogenation reaction (endothermic reaction) after unloading. To improve the economics of MCH, it is important to reduce the heat supply cost in addition to the points figured out in the previous paragraph (capital cost of carrier production and procurement cost of feedstock energy). If effective utilization of waste heat from the hydrogen consumer side can be achieved, there is a possibility to improve the economics. With this background, Case 7 (domestic methane synthesis from MCH hydrogen) is more expensive than the overseas synthetic methane in Cases 1 and 2. For liquefied hydrogen, it was suggested that the costs for the export port, transportation, and import port would be challenges. It will be key to have future technological development in the hydrogen liquefaction process and in liquefied hydrogen storage tanks and ships.

2. Economic evaluation of whole supply chains from overseas to domestic consumers

In Chapter 1, we evaluated the economics of hydrogen carriers imported from overseas, but only to the reconversion to hydrogen after unloading (excluding synthetic methane), and downstream consumers are not in the scope. However, in reality, it is important to evaluate the economics of hydrogen carriers including the consumers. Therefore, this chapter specifically assumes hydrogen carrier consumers and evaluates the economic performance including cost up to the end-use consumers. Electricity generation and heat use are considered as the end-use forms of hydrogen carriers.

2.1. Power generation use

In the case of power generation, we assume that a power plant is located adjacent to the hydrogen carrier unloading (receiving) port, and delivery costs from the unloading base to the power plant are not taken into account.

2.1.1. Power generation technology

We assume three power generation technologies: Gas Turbine Combined Cycle (GTCC) for synthetic methane as for LNG, hydrogen GTCC for liquefied hydrogen and MCH, and ammonia cracked hydrogen GTCC for ammonia. All technologies are assumed to be single-fuel-firing (not co-firing with natural gas). Ammonia cracked hydrogen GTCC is a technology in which a portion of recovered waste heat from gas turbine is used in ammonia cracking and the hydrogen extracted is fed into the hydrogen gas turbine [5].

2.1.2. Major assumptions

The annual fuel demand at the power plant is assumed to be the amount of fuel arriving at the unloading port in Chapter 1. The factors for the power generation cost assessment follow the METI [6] for GTCC and hydrogen GTCC. The LHV-based power generation efficiency is 60% and 64.3%, and the construction cost is JPY 161,000/kW for both. For the ammonia cracked hydrogen GTCC, the power generation efficiency is assumed to be 60% on LHV basis, which is equivalent to GTCC based on [5], and the total capital cost is assumed to be JPY 238,000/kW based on [7]. For other details, see the Appendix.

2.1.3. Analysis results

Figure 2-1 shows the results of the power generation cost estimation. As shown in Chapter 1, the import cost of ammonia is the least expensive among fuels derived from renewable electricity, but the capital cost of ammonia cracked hydrogen GTCC is expensive, so the innovative synthetic methane with GTCC is the least expensive in terms of power generation cost. On the other hand, in the case of natural gas derived synthetic methane (with CCS), the costs of synthetic methane (conventional technology) × GTCC and ammonia cracked hydrogen GTCC are almost equivalent.

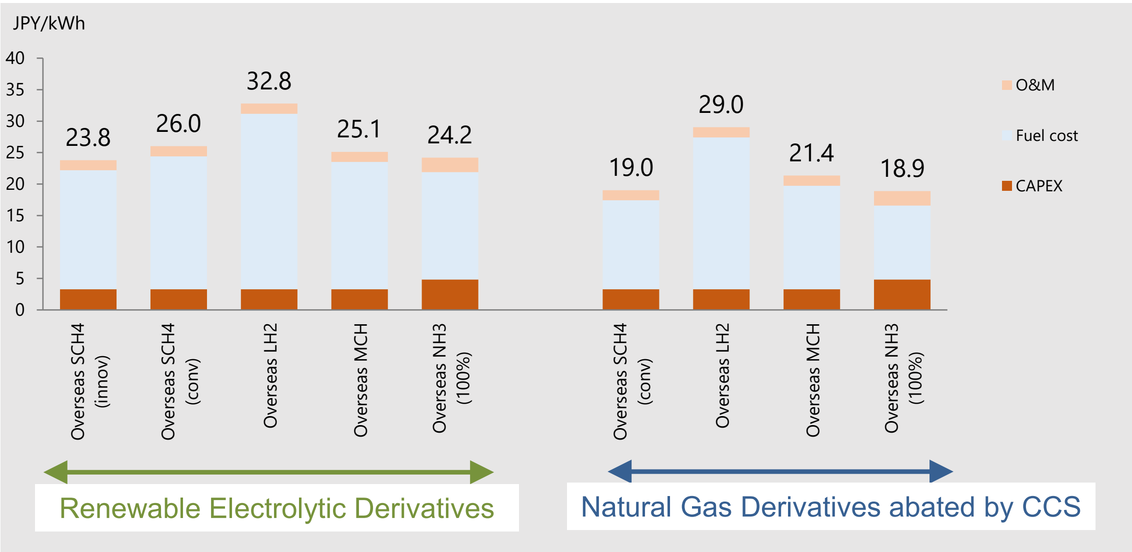

Figure 2-1 Results of power generation cost estimation

2.2. Heat use

In the case of heat use, delivery to the end-user is assumed to be by truck and existing infrastructure (existing city gas pipelines). In addition, a boiler is assumed as the heat use application.

2.2.1. Transportation routes

Two cases were assumed with synthetic methane delivery to end-users: LNG trucks and existing city gas pipelines. For others (liquefied hydrogen, MCH, and ammonia), two cases were assumed: trucks and hydrogen pipelines (in the case of direct use of ammonia, only truck delivery was assumed). Furthermore, in the case of truck delivery, dehydrogenation of MCH or cracking of ammonia is performed at a satellite base located near the end user. In the case of hydrogen pipelines, dehydrogenation and cracking are performed at the receiving port. Three cases of end-use equipment are assumed: gas boilers, hydrogen boilers, and ammonia boilers (Table 2-1).
In all cases, the delivery distance is assumed to be 50 kilometers.

Table 2-1 Hydrogen carrier delivery methods and hydrogen carrier usage forms for heat use

Hydrogen carrier	Delivery method	Satellite base	End-use equipment
Synthetic methane	Existing gas pipelines	-	Gas boilers
	LNG trucks	LNG satellite bases	
Liquefied hydrogen	Liquified hydrogen trucks	Liquified hydrogen satellite bases	Hydrogen boilers
	Hydrogen pipelines	-	
MCH	MCH trucks	MCH satellite bases (including dehydrogenation)	Hydrogen boilers
	Hydrogen pipelines	-	
Ammonia	Ammonia trucks	Hydrogen use Ammonia satellite bases (including ammonia cracking)	Hydrogen boilers
		Direct ammonia use Ammonia satellite bases	Ammonia boilers
	Hydrogen pipelines	-	Hydrogen boilers

2.2.2. Major assumptions

The amount of annual fuel demand (= annual amount of fuels delivered by trucks) for the consumer is defined as the amount of fuel arriving at the unloading port in Chapter 1. The scale of the satellite base is set based on a report [8]. See the Appendix for detailed assumptions for satellite bases, LNG trucks, liquefied hydrogen trucks, MCH trucks, ammonia trucks, truck travel patterns, and labor costs.

The assumptions for dehydrogenation or ammonia cracking equipment in the case of MCH and ammonia (hydrogen use) are the same as those assumed for the international supply chains in Chapter 1. The electricity price (USD 158/MWh) and city gas price (USD 35/MWh) are also the same as those assumed for the international supply chains.

When the transportation method is existing city gas pipelines (synthetic methane), the delivery cost is assumed to be JPY 3.5/Nm^3-CH_4 based on the price of city gas pipeline usage. See the Appendix for more details. The various factors used to evaluate the unit delivery cost of a hydrogen pipeline are based on a report [9]. Specifically, the cost of pipeline construction is JPY 32,000/(inch*m), the pipe diameter is 500 mm, the variable cost is 100 million yen/year, and the hydrogen transportation volume is 100,000 tons/year.

For the boiler on the consumer side, based on the scale of the satellite base, the boiler capacity was set at 1,000 kg/h x 2 boilers. The capital cost is assumed to be 10 million yen/unit, 95% efficiency, and 80% capacity factor.

2.2.3. Analysis results

Figure 2-2 shows the results of heat use cost estimation. The heat use cost of synthetic methane with existing gas pipelines is the lowest cost option because domestic transportation costs can be significantly reduced by using existing gas pipelines. In the case of truck delivery, the heat use costs of synthetic methane and ammonia are at the same level. In the case of hydrogen pipelines, the heat use costs of MCH and ammonia are comparable and less expensive than liquefied hydrogen. The hydrogen use case also shows that the delivery cost of hydrogen pipelines is less expensive than that of trucks. The hydrogen pipeline costs assumed in this estimation are based on the condition that the pipelines are located near the receiving base (unloading port), which is considered to have few restrictions on the construction of hydrogen pipelines. It should be noted that the cost of a hydrogen pipeline passing through a city gas area would be higher than assumed due to the many restrictions on laying pipelines.

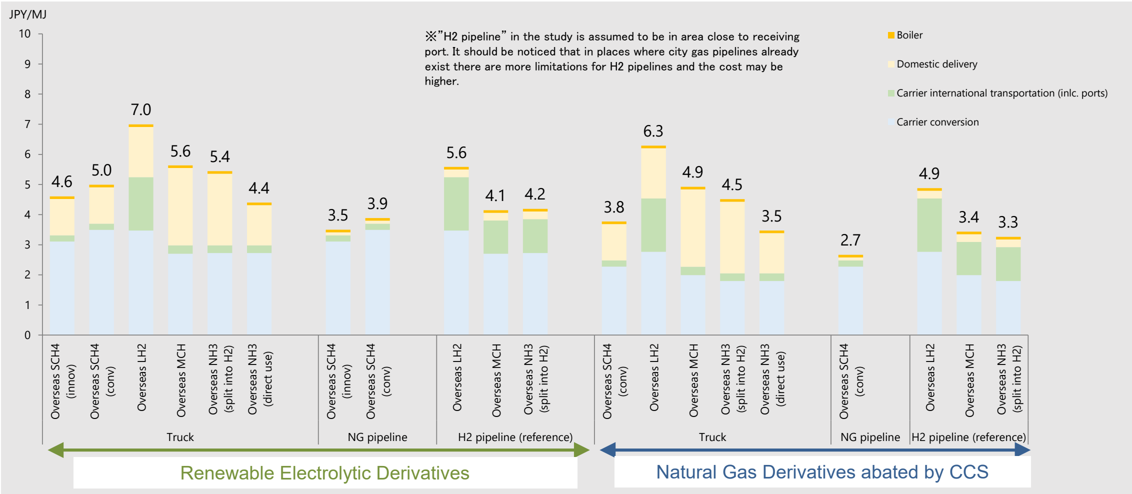

Figure 2-2 Results of heat use cost estimation

3. Economic evaluation based on CO_2 emissions of entire hydrogen supply chains

In this chapter, the economic evaluation is conducted considering the carbon footprint (carbon emission intensity) of entire hydrogen supply chains. In June 2023, the EU Renewable Energy Directive announced its definition of renewable fuels of non-biological origin (RFNBO) in conjunction with its definition of renewable hydrogen, which allows for a conditional deduction of the CO_2 emitted during the combustion of synthetic fuels and gases.[1] In Japan, institutional discussions on CO_2 emissions attribution between original emitters of CO_2 and synthetic methane users are underway.[2] Although the carbon footprint of synthetic methane varies depending on how international rules are formed regarding the attribution of CO_2 emissions from the combustion of synthetic fuels and gases, CO_2 emissions from synthetic methane combustion are assumed to belong to the original CO_2 emitters in this analysis.

3.1. Major assumptions

The carbon footprint of hydrogen supply chains is evaluated by taking into consideration hydrogen production, carrier conversion, export ports, shipping, unloading (receiving) ports, and domestic delivery. CO_2 emissions for each process are calculated by the consumption of fuel and the CO_2 emission factor of the fuel. Note that GHG emissions associated with the upstream development of fossil fuels for natural gas-derived (with CCS) hydrogen and ammonia production were not considered.

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[1] Together with biological origin CO_2 and direct air capture (DAC)-derived CO_2, CO_2 emissions from power generation facilities can be deducted until 2035 and CO_2 emissions from the industrial sector until 2040 (https://energy.ec.europa.eu/system/files/ 2023-02/C_2023_1086_1_EN_ACT_part1_v5.pdf).

[2] 6th Methanation Promotion Public-Private Council, "Interim Report on CO_2 Counting during Combustion of Synthetic Methane," March 22, 2022.

The energy input for each process is shown in Table 3-1.

See the Appendix for emission factors of fuels. Emission factors for grid electricity are taken from the "Announced Pledges Scenario" for 2040 in the IEA's "World Energy Outlook 2022". The exporting country is assumed to be in the Middle East, as in the international supply chains in Chapter 1.

Table 3-1 Energy inputs in each process

Process		Hydrogen carrier			
		Synthetic methane	Liquified hydrogen	MCH	Ammonia
Hydrogen production and carrier synthesis	Renewable electricity	Innovative synthesis technology Renewable electricity Conventional technology Renewable electricity	Renewable electricity	・Hydrogen production: Renewable electricity ・Carrier conversion: Grid electricity, natural gas	・Hydrogen production: Renewable electricity ・Ammonia synthesis: Grid electricity
	Natural gas (with CCS)	Conventional technologies ・Hydrogen production: Gas reforming (CO_2 capture rate: 90%) ・Methane synthesis: Grid electricity	・Gas reforming (CO_2 capture rate: 90%)	・Hydrogen production: Gas reforming (CO_2 capture rate: 90%) ・Carrier conversion: Grid electricity, natural gas	・Ammonia production: Natural gas (CO_2 capture rate: 95%) Power input: Grid electricity
Liquefaction, etc.		Liquefaction: Grid electricity (exporting country)	Liquefaction: Grid electricity (exporting country)	-	-
Export port storage		Grid electricity (exporting country)	Grid electricity (exporting country)	Grid electricity (exporting country)	Grid electricity (exporting country)
Fuel for international shipping		LNG (synthetic methane)	Hydrogen	Fuel oil	Ammonia
Receiving port storage		Grid electricity (Japan)	Grid electricity (Japan)	Grid electricity (Japan)	Grid electricity (Japan)
Domestic transportation	For power generation	N/A	N/A	Dehydrogenation: Grid electricity (Japan), heat (city gas)	N/A
	For heat use	・Truck delivery: Diesel ・Satellite base: Grid electricity	・Truck delivery: Diesel Satellite base: Grid electricity	・Truck delivery: Diesel ・Satellite base (including dehydrogenation): Grid electricity (Japan), heat (city gas)	Hydrogen use ・Truck delivery: Diesel ・Satellite base (including ammonia cracking): Grid electricity (Japan), heat (city gas) Direct use of ammonia ・Truck delivery: Diesel Satellite base: Grid electricity
		・Existing gas pipeline: None	・Hydrogen pipeline: None	・Hydrogen pipeline (dehydrogenation at receiving port): Grid electricity (Japan), heat (city gas)	Hydrogen use ・Hydrogen pipeline (dehydrogenation at receiving port): Grid electricity (Japan), heat (city gas)

3.1.1. Power generation use

Figure 3-1 shows the results of the carbon footprint evaluation for power generation use. For fuels derived from renewable electricity, the carbon footprint of synthetic methane is the smallest, and for fuels derived from natural gas (with CCS), the carbon footprint of ammonia is the smallest. On the other hand, MCH, with its high fuel consumption in international shipping and CO_2 emissions from dehydrogenation, has the largest carbon footprint in both cases.

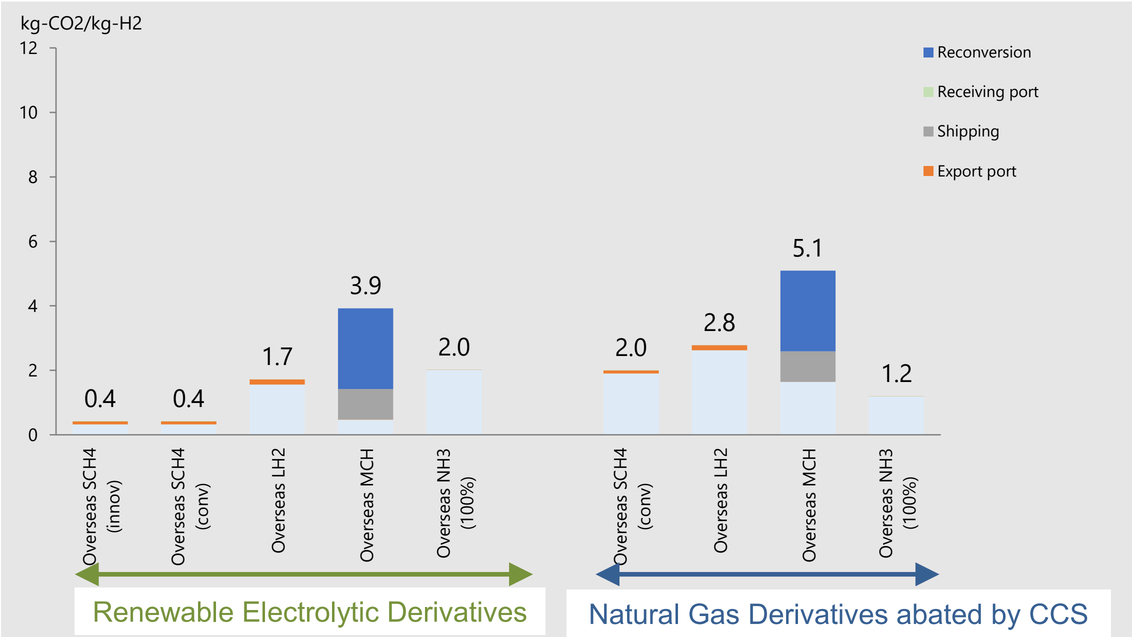

Figure 3-1 Carbon footprint of fuels for power generation

3.1.2. Heat use

Figure 3-2 shows the results of the evaluation of carbon footprint for heat use. CO_2 emissions related to domestic delivery have a significant impact on the carbon footprint of the entire supply chain. Therefore, the carbon footprint of synthetic methane with existing gas pipelines, where existing city gas infrastructure can be used, is the smallest. In the case of truck delivery, as in the case of power generation use, the fuel with the smallest carbon footprint is synthetic methane when derived from renewable electricity and ammonia when derived from natural gas (with CCS).

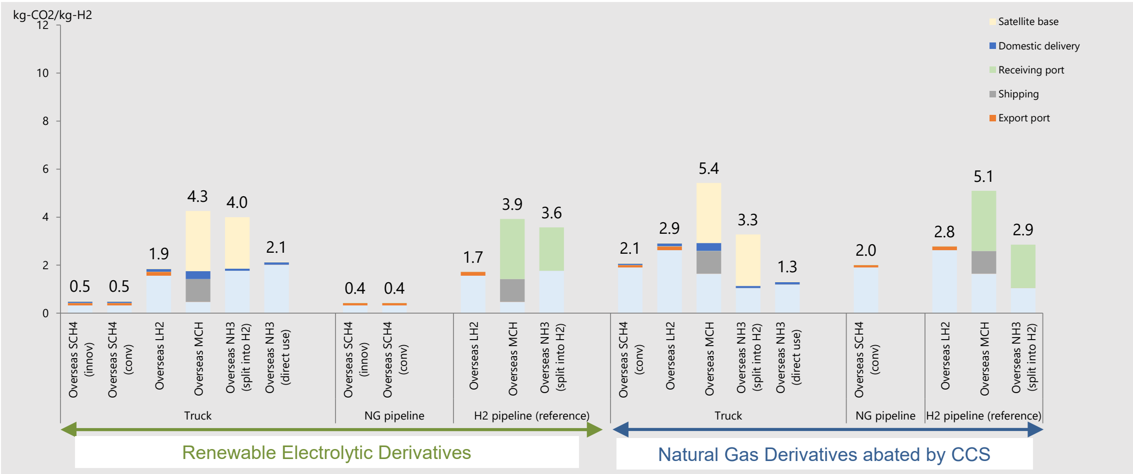

Figure 3-2 Carbon footprint in the case of heat use

3.2. Analysis results: Economics

Figure 3-3 (power generation use) and Figure 3-4 (heat use) show the results of cost estimation assuming a carbon price of JPY10,000/t-CO_2. Synthetic methane and ammonia have a small carbon footprint in the fuel supply chain, so maintain a cost advantage even when carbon costs are added.

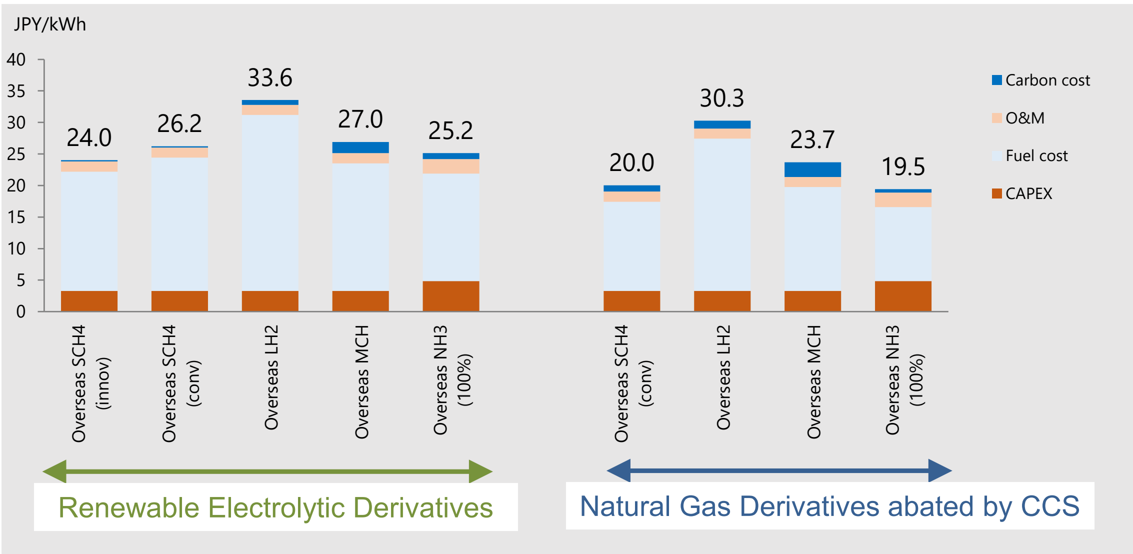

Figure 3-3 Cost of power generation including carbon costs

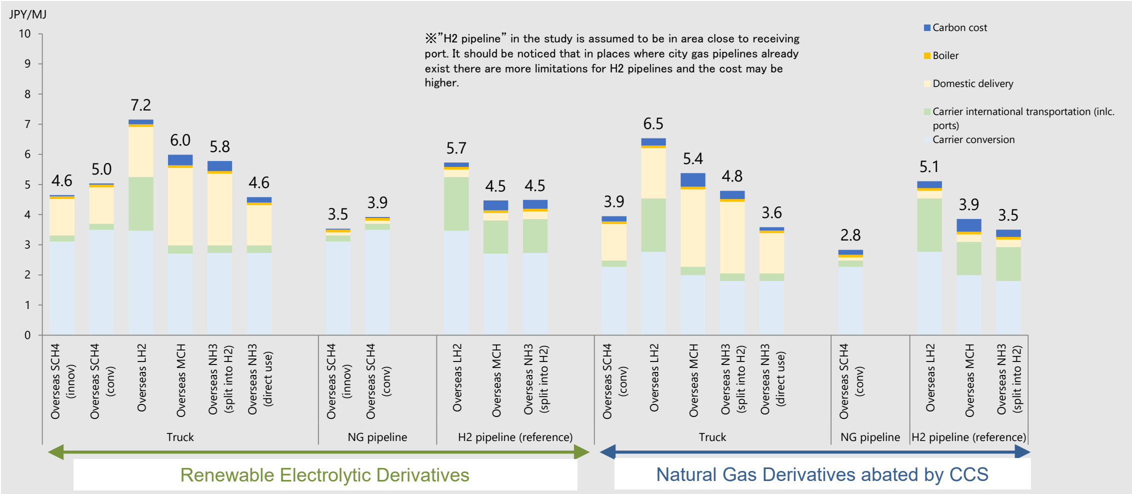

Figure 3-4 Cost of heat use including carbon costs

Conclusion

This study analyzed the economics and CO_2 emissions of the entire supply chains of hydrogen carriers. The results of the analysis are summarized below.

- With regard to international supply chains, ammonia (direct use) is the least expensive for renewable electricity-derived carriers, followed by synthetic methane (innovative technology) and synthetic methane (conventional technology). For natural gas-derived carriers (with CCS), ammonia (direct use) is the least expensive, followed by synthetic methane (existing technology).
- In terms of power generation costs including the domestic supply chain, among the renewable electricity-derived carriers, the most inexpensive is synthetic methane (innovative technology), followed by ammonia cracking hydrogen. Among the natural gas-derived carriers (with CCS), ammonia cracking hydrogen and synthetic methane (conventional technology) are at about the same level.

  In terms of heat use costs including the domestic supply chain, the impact of domestic delivery costs is significant, and synthetic methane is the least expensive through utilization of existing gas pipelines and other infrastructure.
- |For the carbon footprint of entire supply chains, the impact of CO_2 associated with grid electricity for carrier synthesis and domestic delivery is significant.

  In the case of power generation use, the carbon footprint of synthetic methane is the smallest among renewable electricity-derived carriers, and that of ammonia is the smallest among natural gas-derived (with CCS) carriers.

  In the case of heat use, the carbon footprint of synthetic methane with existing gas pipelines is the smallest because truck delivery can be avoided by utilizing existing city gas infrastructure. On the other hand, the carbon footprint of MCH is the largest due to the high fuel consumption in international transportation and dehydrogenation.

Even after counting in the carbon price, synthetic methane and ammonia can maintain their cost advantage due to their small carbon footprints throughout the supply chain.

References

[1] The Institute of Energy Economics, Japan, "Study on the Economics of the Green Hydrogen International Supply Chain" (2021).

[2] Takashi Otsuki, Yoshiaki Shibata: "Estimation of Production and Supply Costs of Synthetic Methane, etc.," 9th Methanation Promotion Public-Private Council, Agency for Natural Resources and Energy, Ministry of Economy, Trade and Industry, Document 3-4 (November 22, 2022)
https://www.meti.go.jp/shingikai/energy_environment/methanation_suishin/pdf/009_03_04.pdf.

[3] International Energy Agency, "The Future of Hydrogen" (2019).

[4] The Ministerial Council on Renewable Energy, Hydrogen and Related Issues, "Basic Hydrogen Strategy," June 6, 2023, p. 11-12,
https://www.cas.go.jp/jp/seisaku/saisei_energy/pdf/hydrogen_basic_strategy_kaitei.pdf.

[5] Nose et al., "Development of Ammonia Utilization Technology for Large Gas Turbines for Power Generation," *Journal of the Combustion Society of Japan*, Vol. 61, No. 198 (2019), 293-298.

[6] Power Generation Cost Verification Working Group, General Resources and Energy Research Committee (8th meeting), August 3, 2021, "List of various power sources."

[7] Basic Policy Subcommittee, General Resources and Energy Research Committee, May 13, 2021; Research Institute of Innovative Technology for the Earth (RITE), "Scenario Analysis of Carbon Neutrality in 2050 (Interim Report)."

[8] The Institute of Applied Energy, "Research Report on Economic Evaluation of Synthetic Methane by Methanation: Domestic Distribution," October 2018.

[9] Kobe/Kansai Hydrogen Utilization Council, May 17, 2021, "Kobe/Kansai Hydrogen Utilization Council Report (FY2020): Organizing a Future Vision for a Hydrogen Society and Quantifying Supply and Demand,"
https://www.obayashi.co.jp/news/upload/img/news20210517_1_02.pdf.

Appendix

Assumptions for power generation

	GTCC	Hydrogen GTCC	Ammonia cracked hydrogen GTCC
Power generation plant capacity	1,000 MW		
Thermal efficiency (LHV basis)	60%	64.3%	60%
Equipment utilization rate	50%		
Operating life	30 years		
Equipment construction cost	JPY 161,000 /kW	JPY161,000/kW	JPY 238,000/kW
Equipment disposal cost (% of construction cost)	5%		
Personnel cost	JPY 620 million/year		
Annual repair cost (% of construction cost)	2.4%		
Other annual expenses (% of construction cost)	1.1%		
Annual general and administrative expenses (% of direct costs)	12%		

Note: Thermal efficiencies of gas and hydrogen power generation are converted to lower heating value.
Sources: Power Generation Cost Verification Working Group (8th meeting), August 3, 2021; Basic Policy Subcommittee, General Resources and Energy Research Committee, May 13, 2021; RITE, "Scenario Analysis of Carbon Neutrality in 2050 (Interim Report)."

Assumptions for domestic delivery (Truck)

	LNG trucks	Liquified hydrogen trucks	MCH trucks	Ammonia trucks
Vehicle price (JPY 10,000/unit)	5,000	5,000	3,000	4,000
Life span (years)	13	13	13	13
Transport capacity (kL)	20	20	20	20
Fuel economy (L diesel oil/t*km)	0.027	0.027	0.027	0.027
Vehicle weight (kg)	24,000	24,000	24,000	24,000

Source: The Institute of Applied Energy, "Research Report on Economic Evaluation of Synthetic Methane by Methanation: Domestic Distribution;" various other sources.

Various conditions for truck transportation

Item	Assumed value
Delivery distance	50 km
Truck speed	50 km/h
Fuel (diesel) price	JPY 130/L
Drivers	2 people/truck
Driver payment	JPY 4.5 million/person
Truck maintenance cost	JPY 218,440/truck

Source: Transportation distance is assumed based on the "Research Report on Economic Evaluation of Synthetic Methane by Methanation: Domestic Distribution" by The IAE. Travel speed is assumed based on the legal speed limit for large freight vehicles. Other assumptions are based on various data.

Assumptions on a satellite base

	LNG satellite base	Liquefied hydrogen satellite base	MCH satellite base	Ammonia satellite base
Tank capacity	40 kL	100 kL	MCH tank: 160 kL Toluene tank: 160 kL	70 kL
Vaporizer, etc.	130 Nm^3-CH_4/h	400 Nm^3-H_2/h	-	-
Dehydrogenation equipment	-	-	400 Nm^3-H_2/h	Hydrogen use: 400 Nm^3-H_2/h Ammonia use: N/A
Total equipment cost	JPY 63 million	JPY 14,000 million	JPY 191 million	JPY 13,500 million
Capacity factor	90%	90%	90%	90%
Equipment life span	30 years	30 years	30 years	30 years
Operation and maintenance cost ratio	4%	4%	4%	4%
Number of operators	5	5	5	5
Unit labor cost	JPY 6 million/person/year	JPY 6 million/person/year	JPY 6 million/person/year	JPY 6 million/person/year
Unit cost of water and sewerage (equivalent to hydrogen HHV)	JPY 0.36/Nm^3-H_2	JPY 0.36/Nm^3-H_2	JPY 0.36/Nm^3-H_2	JPY 0.36/Nm^3-H_2
Electricity	JPY 1.08/Nm^3-H_2	JPY 1.08/Nm^3-H_2	Estimated by dehydrogenation electricity consumption and electricity rate	Hydrogen use Trial estimation based on ammonia cracking electricity consumption and electricity rates Ammonia direct use JPY 1.08/Nm^3-H_2
Heat	-	-	Estimated with dehydrogenation heat consumption and gas price	Estimated ammonia cracking heat consumption and gas price

Source: The Institute of Applied Energy, "Research Report on Economic Evaluation of Synthetic Methane by Methanation: Domestic Distribution."

Assumptions for natural gas pipeline utilization cost estimation

Item		Assumed value
Gas transportation volume	Monthly gas consignment volume (converted to m^3)	52,535,921 m^3-CH_4/month
	Outgoing gas volume	71,967 m^3/h
Gas consignment unit price	Basic rate	JPY 227,570 /month
	Basic flow rate	JPY 675/m^3・h
	Metered charge (winter)	JPY 1.72/m^3
	Metered charge (other)	JPY 1.36/m^3
	Additional metered rate unit price for low-pressure pipeline use	JPY 1.97/m^3

Source: Tokyo Gas, "Terms and Conditions of Retail Consigned Supply Service (Consigned Supply to be Paid at the Point of Demand)" (Type 2, Part 1)

Gas consignment charge calculation formula
Gas consignment charge = Basic charge + Basic flow rate * Maximum gas volume discharged + (Metered charge + Low pressure pipeline use) * Gas demand

CO_2 emission factor

Fuel	Emission coefficient
Renewable electricity	0
Natural gas	0.056kg-CO_2/MJ
Grid electricity in exporting country	0.236kg-CO_2/kWh
Ship fuel: Synthetic methane	0
Ship fuel: Hydrogen	0
Ship fuel: Fuel oil	0.072kg-CO_2/MJ (C heavy oil)
Ship fuel: Ammonia	0
Japan grid electricity	0.041kg-CO_2/kWh
Diesel	0.0686kg-CO_2/MJ
City gas (Japan)	0.050kg-CO_2/MJ

Source: Ministry of the Environment; IEA World Energy Outlook 2022, Announced Pledges Scenarios, 2040.

A Thermodynamic Consideration of the Aerothermal Energy and Ground Heat Used by Heat Pumps

- The Importance of Heat Pumps and the Interpretation of Aerothermal Energy -

Yoshiaki Shibata*

Summary

Heat pumps are high efficiency equipment that are widely used for air conditioning and water heating and play an important role in the electrification that is promoted toward decarbonization. On the other hand, there need to be careful discussions on the interpretation of the heat that heat pumps use as the heat source, which include aerothermal energy (or ambient heat), ground heat and water heat. In the EU, heat such as aerothermal energy, ground heat and water heat utilized by heat pumps whose purpose is heating and cooling is defined as natural heat, or in other words renewable energy, and a formula to define these types of heat as renewable energy was established for cooling-purpose heat pumps in 2022, followed by a formula for heating-purpose heat pumps in 2009. However, while ground heat and water heat can be regarded as renewable energy in the sense that they utilize differences from the ambient temperature, there needs to be a careful discussion when it comes to aerothermal energy, which has the ambient temperature. This paper, based on a scientific viewpoint, organizes the interpretation of natural heat by comprehensively addressing the mechanism of heat pumps used for heating and cooling.

When the heat (absorbed from the environment) used by heating-purpose heat pumps is aerothermal energy, the aerothermal energy is artificial heat that becomes a usable state only when electricity is input, and since it does not exist originally in nature, it cannot be regarded as natural heat. From this viewpoint, defining the aerothermal energy as renewable energy is inappropriate. It is undoubtedly appropriate to regard the energy obtained by differences between the ambient temperature and the temperature of the utilized heat (such as ground heat and water heat) as renewable energy. When the heat used by heat pumps is ground heat, it can be regarded as renewable energy, as the heat pumps utilize natural heat by exploiting differences from the ambient temperature, but the quantity of ground heat as renewable energy should be defined as the difference in the electricity consumption between an air-source heat pump and a ground-source heat pump, in other words, the amount of electricity consumption that can be saved by elevating the efficiency of a heat pump through utilizing ground heat.

The function of cooling-purpose heat pumps is to remove heat from a certain space and discard the removed heat to the environment. The EU's Renewable Energy Directive (RED) defines part of this removed heat as renewable energy, but the removal of heat is the provision of cooling and is cooling demand itself; it is not the utilization of natural heat that exploits difference from the ambient temperature. From this viewpoint, it is undoubtedly inappropriate to regard cooling demand as renewable energy. Based on the definition formula in the EU's RED, generating and utilizing more cooling by consuming a larger quantity of electricity will result in more "renewable energy" being utilized. On the other hand, if ground heat is utilized, similarly to the case of heating-purpose heat pumps, the quantity of ground heat as renewable energy can be defined as the difference in the electricity consumption between an air-source heat pump and a ground-source heat pump, in other words the amount of electricity consumption that can be saved by elevating the efficiency of a heat pump through utilizing ground heat.

Even if the aerothermal energy utilized in heating-purpose heat pumps is regarded as "renewable energy" and is added to renewable energies such as solar photovoltaics and wind power to statistically increase the quantity of renewable energy introduced, it is needless to say that the volume of energy consumed and CO_2 emitted by a country or region as a whole does not change. This is because the energy saving effects of the heat pumps that are in operation are already being reflected in a country or region's overall current energy consumption and CO_2 emissions. Consequently, defining the aerothermal energy used by heat pumps as renewable energy and adding it to the quantity of renewable energy introduced ostensibly inflates renewable energy statistics. However, because that aerothermal energy does not have the effects that renewable energies like solar photovoltaic and

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wind power possess, such as reducing CO_2 emissions and enhancing the self-sufficiency rate, there is a possibility that an intermixed element would be introduced into the original goals of renewable energy policy. Furthermore, in the case of cooling-purpose heat pumps, they do not utilize aerothermal energy, and only supply cooling as a result of electricity consumption by the heat pumps.

Heat pumps are excellent high-efficiency equipment (energy-saving equipment). Increasing the uptake of high-efficiency (as primary energy basis) heat pumps can be expected to have energy consumption and CO_2 emissions reduction impacts. Heat pumps should be promoted on the basis of scientific verification focusing on the intrinsic contributions that renewable energy possesses for reducing CO_2 emissions and enhancing the self-sufficiency rate, rather than focusing on numerical target of renewable energy.

1. Introduction

Heat pumps are high efficiency equipment that are widely utilized for air conditioning and water heating, and play an important role in the electrification that is being promoted toward decarbonization. On the other hand, there needs to be careful discussions about the interpretation of the heat that heat pumps use as the heat source, which include aerothermal energy (or ambient heat), ground heat and water heat.

In the EU these forms of heat used by heat pumps have been regarded as "natural heat," defined as renewable energy and included in the statistic amount of renewable energy introduced. The EU's Renewable Energy Directive (RED) had prescribed in 2009 a method for calculating the heat volume in cases where these forms of heat are used by heating-purpose heat pumps (space heating and water heating), and in June 2022 a calculation method for cooling-purpose heat pumps (space cooling) was also established[1]. In Japan, in 2009 the Act on Sophisticated Methods of Energy Supply Structures defined ambient heat as natural heat in the same category as ground heat with the phrase "heat in the atmosphere and other heat that exists in the nature"[2], but the Act does not present a method for calculating the quantity of ambient heat used. The government councils[3] also discuss how natural heat should be categorized.

It is understandable to regard ground heat and water heat, which have temperature different to ambient temperature, as "natural heat" and defining them as renewable energy, but there will be debates on whether or not aerothermal energy, whose temperature is ambient temperature itself, should be defined as renewable energy. The author has ever concluded in 2010 that it might be possible to regard aerothermal energy used by heating-purpose heat pumps as renewable energy, while aerothermal energy should not be classified in the same category as the other renewable energy because heat pumps require electricity in conjunction with the aerothermal energy [1]. Responding to the EU's RED which subsequently presented a new definition of renewable energy in cooling-purpose heat pumps in 2022, this paper will reconstruct interpretation of natural heat by carefully examining the RED, and by comprehensively reconsidering the mechanism of heating and cooling-purpose heat pumps from a scientific point of view. Though there are two types of heat pumps, electrically driven and heat-driven, this paper targets the electrically driven type that accounts for the majority of the heat pumps in use.

2. The aerothermal energy used in heating-purpose heat pumps is artificially generated

First, aerothermal energy used by heat pumps will be addressed. Heating-purpose heat pumps are targeted (cooling-purpose heat pumps will be discussed later). Heating-purpose heat pumps are mostly used for space heating for households and commercial buildings. The mechanism is that the total of the electricity input to the heat pump and the amount of heat (aerothermal energy) absorbed from the ambient air as a result of the thermodynamic cycle powered by the electricity is supplied as heat (see the left side of Figure 1). In other words, assuming that the electricity input is EL, the amount of heat absorbed from the ambient air is Q_L and the heat supplied is Q_H,

$$EL + Q_L = Q_H \tag{1}$$

The aerothermal energy is Q_L, and it is observed that the heat pump uses aerothermal energy in combination with electricity in order to satisfy the heating demand (service demand) of Q_H. In the case of heating-purpose heat pumps, the Coefficient of Performance (COP), an indicator of heat pump efficiency, is expressed as the ratio of the heat supplied to the electricity input:

$$COP_H = \frac{Q_H}{EL} \tag{2}$$

1 https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:02018L2001-20220607&from=EN#tocId64

2 "Treatment of natural heat in the revised Act on the Rational Use of Energy", Reference material 2, Working Group on Standards for Factories, Energy Efficiency and Conservation Subcommittee, Committee on Energy Efficiency and Renewable Energy, FY2022 Fourth Advisory Committee for Natural Resources and Energy

3 For example, the 63rd Power and Gas Basic Policy Subcommittee, Electricity and Gas Industry Committee, Advisory Committee for Natural Resources and Energy

and aerothermal energy Q_L is identified from formulas (1) and (2) as below:

$$Q_L = Q_H\left(1 - \frac{1}{COP_H}\right) \tag{3}$$

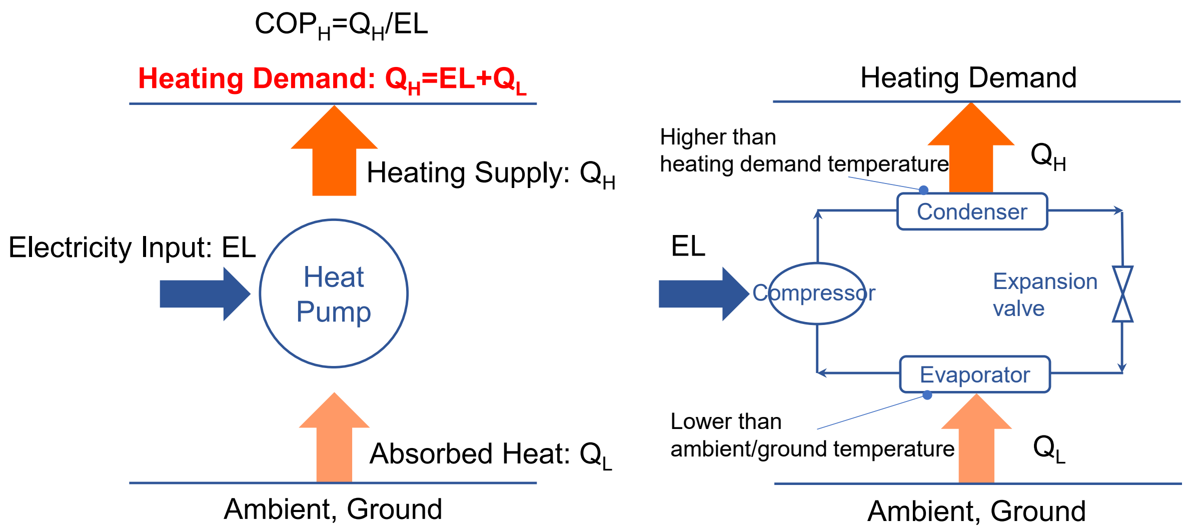

Figure 1 Mechanism of Heating-purpose Heat Pump

The definition formula prescribed in the EU's RED is

$$E_{RES} = Q_{usable} \times \left(1 - \frac{1}{SPF}\right) \tag{4}$$

where E_{RES} is aerothermal energy that the EU's RED regards as renewable energy, Q_{usable} is the amount of heat that is supplied, and SPF is average COP_H in the overall heat supply period (season)[4]. Substituting Q_L in formula (3)'s for E_{RES}, Q_H for Q_{usable} and COP_H for SPF, it becomes formula (4). In other words, the EU's RED regards Q_L (aerothermal energy) as renewable energy.

However, there is a need to take a deep dive into why aerothermal energy, which has the ambient temperature, becomes usable. Heat becomes useable only when its temperature is different from the surroundings temperature. For example, ground heat and water heat being warmer than the ambient temperature during winter and cooler in summer have value to be used, but aerothermal energy is the ambient itself, with no temperature difference available, and consequently there is no value as it is.

Then, let us take a more detailed look at the mechanism of heat pumps (See the right side of Figure 1). A heat pump is made up of a compressor, condenser, expansion valve and evaporator, and refrigerant circulates through these components. Thanks to electricity input, the compressed refrigerant reaches a high temperature and high pressure, then provides heat (warms a room) by releasing the heat at the condenser. The refrigerant exiting the condenser passes through the expansion valve and becomes cooler than the ambient temperature, enabling to absorb heat from the ambient at the evaporator. Having absorbed heat from the ambient air, the refrigerant is returned to the compressor and its temperature and pressure increased again. This series of steps in a cycle is repeated. The heat absorbed at the evaporator from the ambient air in this cycle is aerothermal energy.

In other words, only when the thermodynamic cycle of a heat pump driven by electricity input brings the refrigerant into a

[4] More specifically, the EU's RED sets a threshold for SPF, and if the heat pump with SPF above the threshold, the aerothermal energy is regarded as renewable energy.

lower temperature state than the ambient air, it becomes possible to absorb heat from the ambient air. It should be noted that the aerothermal energy does not exist in nature originally. Aerothermal energy becomes usable because colder-than-ambient state (a lower temperature state) which is artificially created by a heat pump is generated within the thermodynamic cycle. Regarding this aerothermal energy as natural heat and defining it as renewable energy is akin to regarding the ice artificially produced in a refrigerator as the same as the snow or ice that exists in the nature.

Accordingly, aerothermal energy that is only utilizable in an artificially created state resulting from the input of electricity does not exist in the nature and cannot be viewed as natural heat. From this standpoint, defining aerothermal energy as renewable energy is inappropriate.

3. Ground heat is renewable energy, but how should it be interpreted when used by heat pumps?

Next, ground heat or water heat is addressed. Naturally, ground heat, which is in winter warmer than the ambient temperature, can be used for heating, and in summer it can be used for cooling, so the whole quantity of heating and cooling used in those purposes can be counted as a quantity of renewable energy. It is in other words the direct utilization of natural heat.

On the other hand, the situation becomes a little complicated when these types of natural heat are utilized in heat pumps. Here, heating-purpose heat pumps with ground heat as an example will be discussed (cooling-purpose heat pumps will be discussed later). As was the case with aerothermal energy, formula (1) is valid. The EU's RED defines ground heat indicated by Q_L in formula (1) as renewable energy, based on the mechanism of heat pump that simply uses ground heat, same as the case of aerothermal energy.

However, theoretically, the value of ground heat stems from its temperature difference compared to the ambient air temperature. If the temperature of ground heat is the same as the ambient air temperature, ground heat is the same as aerothermal energy and has no value. Based on this logic, the quantity of heat corresponding to the difference in temperature between ground heat and ambient air should be regarded as renewable energy. To identify this quantity of heat it is helpful to look into the principle of heat pumps. Because the temperature of ground heat (in winter) is higher than that of aerothermal energy (ambient temperature) it becomes easier to supply heat to the refrigerant from ground heat (see the evaporator on the right side of Figure 1), and being able to absorb a greater quantity of heat offers the benefit of reducing the amount of electricity input to the heat pump (increasing efficiency). In other words, this is the same principle as an air-source heat pump when the ambient air temperature is high[5]. Based on this principle, the quantity of heat that ground-source heat pumps utilize as renewable energy can be identified as the difference in electricity consumption between an air-source heat pump and a ground-source heat pump (the heating demand should be same for both).

Formulas (5) and (6) below illustrate formula (1) in the case of aerothermal energy use and ground heat use, respectively (subscript A refers to aerothermal energy while subscript G refers to ground heat):

$$EL_A + Q_{LA} = Q_H \qquad \text{aerothermal energy} \qquad (5)$$
$$EL_G + Q_{LG} = Q_H \qquad \text{ground heat} \qquad (6)$$

Q_H is heating demand (service demand) and is the same for both. The heat used is Q_{LA} in the case of aerothermal energy and Q_{LG} in the case of ground heat. The electricity input is E_{LA} and E_{LG}, respectively. Based on the above-mentioned logic, the value of ground heat as renewable energy is Q_{LG}e- Q_{LA}, expressed from formula (5) and (6) by EL_A - EL_G, which means that the quantity of ground heat as renewable energy is able to be identified by the difference in electricity consumptions.

The principle is that only the quantity of heat originating from the difference from the ambient temperature (the outside temperature in the case of air conditioning)[6] is usable for whatever the type of heat.

[5] When air conditioners are used for space heating, the lower (higher) the ambient air temperature is, the lower (higher) the efficiency is, thus increasing (decreasing) the electricity consumption.

[6] However, it is necessary to bear in mind that in the case of substances like water, although there is no temperature change during phase changes, the latent heat is useable.

The rationality of this method for identifying the quantity of ground heat as renewable energy is corroborated when discussing cooling-purpose heat pumps.

4. Cooling-purpose heat pumps only use the ambient air as a place to discard heat

Next, cooling-purpose heat pumps will be addressed. Air conditioners for household space cooling are good example for cooling-purpose heat pumps. As shown in Figure 2, the flow of energy of cooling-purpose heat pumps is the same as heating-purpose heat pumps (Figure 1), but it should be noted that the objective is opposite[7]. Formula (1) is valid as it is, but unlike the case of heating-purpose heat pump where Q_H is service demand, Q_L is service demand in case of cooling-purpose heat pump as the purpose is to remove heat. Modifying formula (1) to

$$Q_H - EL = Q_L \quad (1)'$$

it becomes easier to understand[8].

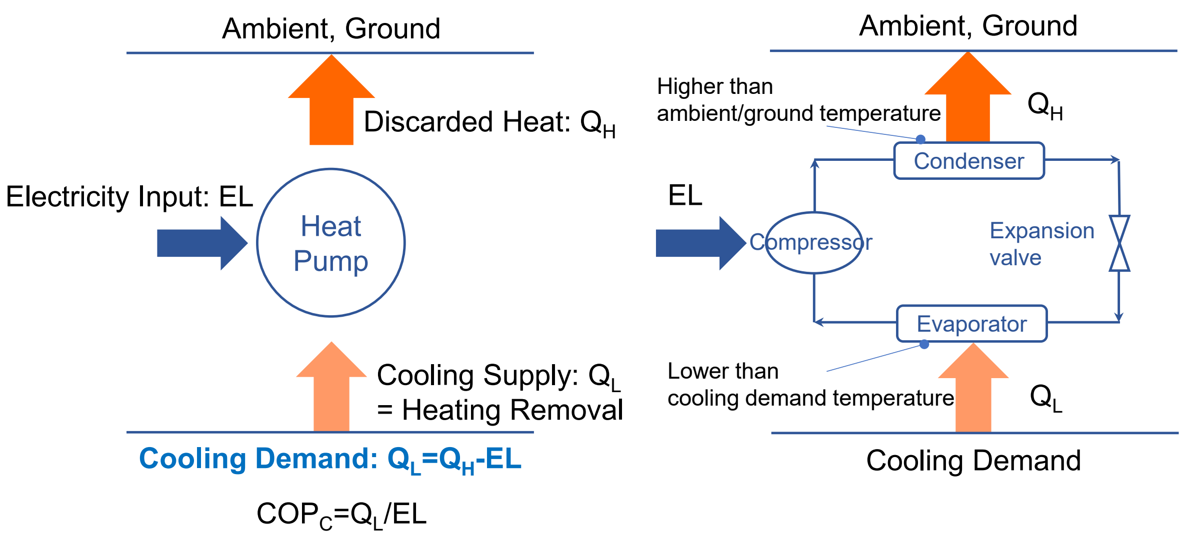

Figure 2 Mechanism of Cooling-purpose Heat Pump

Here, how the EU's RED defines the renewable energy in cooling-purpose heat pumps will be examined. Formula (7) below is established to specify the quantity of renewable energy with regard to cooling purposes.

$$E_{RES-C} = (Q_{CSource} - E_{INPUT}) \times S_{SPFp} = Q_{CSupply} \times S_{SPFp} \quad (7)$$

where:

$E_{RES\text{-}C}$: Renewable energy in cooling
$Q_{CSource}$: Heat released to the environment
E_{INPUT} : Energy consumption in the cooling supply system
$Q_{CSupply}$: Supplied Cooling
S_{SPFp} : Proportion of the supplied cooling that can be regarded as renewable energy (%)

There are provisions for S_{SPFp} depending on the efficiency (SPF) of heat pumps, and more renewable energy is acknowledged

[7] Air conditioners are operated in reverse for heating purposes and cooling purposes, in other words, the direction of the refrigerant flow is reversed.
[8] The coefficient of performance is $COP_C = \frac{Q_L}{EL}$ and cooling demand can be expressed as $Q_L = \frac{Q_H}{1+\frac{1}{COP_C}}$.

for higher efficiency heat pumps., $Q_{CSource}$ in formula (7) corresponds to Q_H in formula (1)', E_{INPUT} to EL and $Q_{CSupply}$ to Q_L, which means that a part of Q_L is defined as renewable energy. However, Q_L is cooling demand (service demand) itself. In other words, in the EU's RED, when heat is removed from a certain space (a room, for example) by cooling-purpose air conditioning, some of the removed heat (taking into account the proportion S_{SPFp}) is viewed as natural heat as renewable energy. This interpretation leads to a logical inconsistency that the more cooling is supplied by consuming more electricity, the greater the volume of renewable energy is used. The EU's RED makes theoretical mistake to regard the heat removed from a room, which is the cooling demand (= cooling load), as renewable energy.

5. How should the ground heat used in cooling-purpose heat pumps be interpreted?

What about cooling-purpose heat pumps that use ground heat? Because ground heat itself is indeed renewable energy, it cannot be said that these heat pumps do not use renewable energy, unlike the fact that air-source heat pumps do not use renewable energy. Nevertheless, according to the logic of the EU's RED (formula (7)), cooling demand ends up becoming renewable energy. Then, the above-mentioned logic established for heating-purpose heat pumps will be applied. In other words, in the case of cooling-purpose heat pumps, a focus is put on the fact that the efficiency (COP) increases by using ground heat that is lower (in summer) than the ambient air temperature. To regard cooling-purpose air-source heat pumps as using renewable energy is logically incorrect, but it is possible to regard the amount of electricity input reduced by improvement of heat pump efficiency through using ground heat as renewable energy. Using formula (1)' to express the case of aerothermal energy and ground heat, respectively, the formula (5)' and (6)' are established.

$$Q_{HA} - EL_A = Q_L \qquad \text{aerothermal energy} \qquad (5)'$$
$$Q_{HG} - EL_G = Q_L \qquad \text{ground heat} \qquad (6)'$$

Here, cooling demand (the quantity of heat removed) shall be same Q_L in both cases. Based on formulas (5)' and (6)', the value of ground heat as renewable energy is EL_A - EL_G (= Q_{HA} - Q_{HG}), which means that ground heat as renewable energy used by heat pumps can be identified from the difference in electricity consumption between ground-source heat pump and air-source heat pump.

6. Summary

The results from the above discussions are summarized below[9].

- When the heat used by heating-purpose heat pumps is aerothermal energy (the heat absorbed from the environment), the aerothermal energy being artificial heat that reaches a useable state only when electricity is input cannot be regarded as natural heat since it does not exist originally in the nature. From this point of view, it is inappropriate to define aerothermal energy as renewable energy. It is rational to regard the heat corresponding to the temperature difference between the heat used (ground heat, water heat etc.) and the ambient as renewable energy. When the heat used by heat pumps is ground heat, it can be regarded as renewable energy, but the quantity of ground heat as renewable energy should be defined as the difference in electricity consumption between an air-source heat pump and a ground-source heat pump, in other words electricity consumption reduction gained through improvement of heat pump efficiency by using ground heat.
- The function of cooling-purpose heat pumps is to remove heat from a certain space and discard the removed heat to the environment. Although the EU's RED defines a portion of this discarded heat as renewable energy, the discarded heat is cooling supply that is cooling demand itself, and not the utilization of natural heat exploiting the differences from the ambient air temperature. From this point of view, it is incorrect to regard cooling demand as renewable energy. The definition formula in the EU's RED leads to a logical inconsistency that the more cooling is supplied by consuming more electricity, the greater

[9] It goes without saying that when ground heat is used directly, the total quantity of ground heat is renewable energy. If for example a room temperature is 30°C while the ambient temperature is 25°C, and ambient air is fed to cool the room, the aerothermal energy can be regarded as renewable energy based on the fact that there is temperature difference. However, in reality it is almost impossible to identify this quantity.

the volume of "renewable energy" is used. On the other hand, if ground heat is utilized, similarly to the case of heating-purpose heat pumps, the quantity of ground heat as renewable energy can be defined as the difference in electricity consumption between an air-source heat pump and a ground-source heat pump, in other words electricity consumption reduction gained through improvement of heat pump efficiency by using ground heat.

It is possible to estimate the quantity of natural heat such as ground heat that a heat pump uses provided that the information below are known; ambient air temperature, heating or cooling demand temperature, electricity consumption by an air-source heat pump, efficiency (COP), ground heat temperature, and relational expressions between efficiency (COP) and ambient air temperature and demand temperature.

It is also possible to estimate the quantity of aerothermal energy utilized by heating-purpose heat pumps and to add this quantity to renewable power generation like solar photovoltaic and wind power for the purpose of increasing the statistic amount of introduced renewable energy. Even if the aerothermal energy utilized in heating-purpose heat pumps is regarded as "renewable energy" and is added to renewable energies such as solar photovoltaics and wind power to statistically increase the quantity of renewable energy introduced, it is needless to say that the volume of energy consumed and CO_2 emitted by a country or region as a whole does not change. This is because the energy saving effects of the heat pumps that are in operation are already being reflected in a country or region's overall current energy consumption and CO_2 emissions. Consequently, defining the aerothermal energy used by heat pumps as renewable energy and adding it to the quantity of renewable energy introduced ostensibly inflates renewable energy statistics. However, because that aerothermal energy does not have the effects that renewable energies like solar photovoltaic and wind power possess, such as reducing CO_2 emissions and enhancing the self-sufficiency rate, there is a possibility that an intermixed element would be introduced into the original goals of renewable energy policy. Furthermore, in the case of cooling-purpose heat pumps, they do not utilize aerothermal energy, and only supply cooling as a result of electricity consumption by the heat pumps.

Heat pumps are excellent high-efficiency equipment (energy-saving equipment). Increasing the uptake of high-efficiency (as primary energy basis) heat pumps can be expected to have energy consumption and CO_2 emissions reduction impacts. Heat pumps should be promoted on the basis of scientific verification focusing on the intrinsic contributions that renewable energy possesses for reducing CO_2 emissions and enhancing the self-sufficiency rate, rather than focusing on numerical target of renewable energy.

Reference

[1] Yoshiaki Shibata, "Aerothermal Energy Use by Heat Pumps in Japan," IEEJ October 2010, IEEJ

Australia's Safeguard Mechanism

Seonghee Kim*

1. Climate change policy outline

In Australia, the course of climate change policy changes frequently as a result of changes in the administration. The Australian Labor Party, which regained power for the first time in eight years as a result of a general election in May 2022, is proactive about climate change policy and has increased the country's 2030 greenhouse gas emissions reduction target to a 43% reduction below 2005 levels, from 26-28% previously. Additionally, in September 2022 it enacted the Climate Change Act 2022, Australia's first climate change legislation.

Up to now, Australia's main climate change policy was the Emissions Reduction Fund (ERF), a system that started in 2015 whereby the government buys up reductions from energy conservation and greenhouse gas reduction projects. In 2012 a fixed price emissions trading scheme that set the price of emission rights at AUD23 (AUD1=JPY96.6) was introduced, but following a change in government from the Labor Party to a conservative coalition in 2013, the fixed price emissions trading scheme was scrapped by (former) Prime Minister Tony Abbott, who adopted a dismissive stance on carbon pricing, and in its place his government introduced the ERF scheme as the country's main climate change policy. The ERF offers incentives to companies to reduce emissions. However, participation in the ERF scheme is voluntary, and because participation was not mandatory, concerns emerged about carbon leakage and the possibility that relying on the scheme alone would not make it possible to ensure Australia's national reduction target is achieved. These concerns led in July 2016 to the introduction of the Safeguard Mechanism as a separate measure for curbing increases in companies' emissions.

The Safeguard Mechanism is a scheme under which the government sets permissible emissions values (or "caps") for greenhouse gas emitting facilities whose annual emissions exceed a certain amount, and controls their adherence to those caps. However, not only does the Safeguard Mechanism set the level of the permissible emission values as "the highest level of reported emissions during a baseline period," but it also permits companies to comply by using average figures spread across several years. In this and other ways, the reduction levels demanded of the companies covered are not strict, and it has been becoming a framework focused on "managing companies' emissions to ensure they do not exceed business as usual (BAU) levels." In light of that, the Labor Government engaged in amending the existing Safeguard Mechanism in a way that would strengthen it. The related amendment bill, the Safeguard Mechanism (Crediting) Amendment Bill 2023, made it through Parliament in March 2023 and entered into force on July 1, 2023. This paper gives an overview of the details of the amended scheme for the Safeguard Mechanism, which will form the main axis of Australia's climate change policy going forward.

2. The Safeguard Mechanism's Scheme Design

2.1. Overview of the Scheme

The Safeguard Mechanism is a system that sets permissible emissions values for facilities with direct annual emissions of 100,000 t-CO_2e or more, and legally obligates the companies to adhere to them. It allows for companies to utilize offset credits to offset their emissions in cases where their emissions exceed the permissible values. The Safeguard Mechanism covers approximately 215 companies in the mining, petroleum, gas, manufacturing, waste and transport sectors, and accounted for around 28% of Australia's total emissions in fiscal 2020. (Figure 1)

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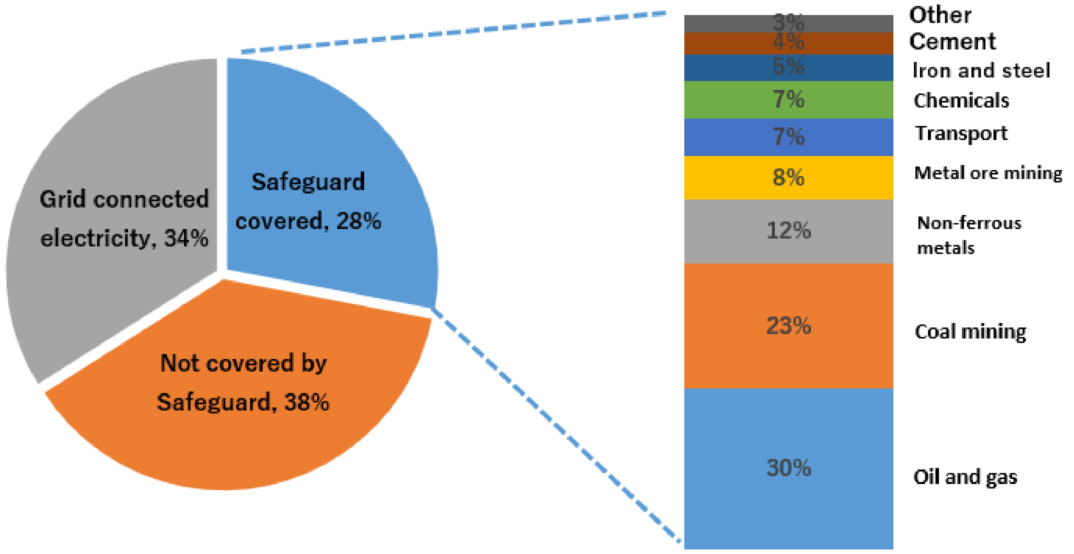

Figure 1 Australia's National Emissions and Safeguard Mechanism

(Source) Carbon Leakage Review Consultation Paper, DCCEEW (2023)[1]

Under the previous Safeguard Mechanism, no emissions cap was set for the scheme as a whole, but in the 2023 amendment, an emissions cap was established that is linked to the national reduction target. Figure 2 shows the Safeguard Mechanism's emission reduction targets. The Safeguard Mechanism's 2030 emissions target of 100 million tons represents a reduction of approximately 27% compared to 2020.[2]

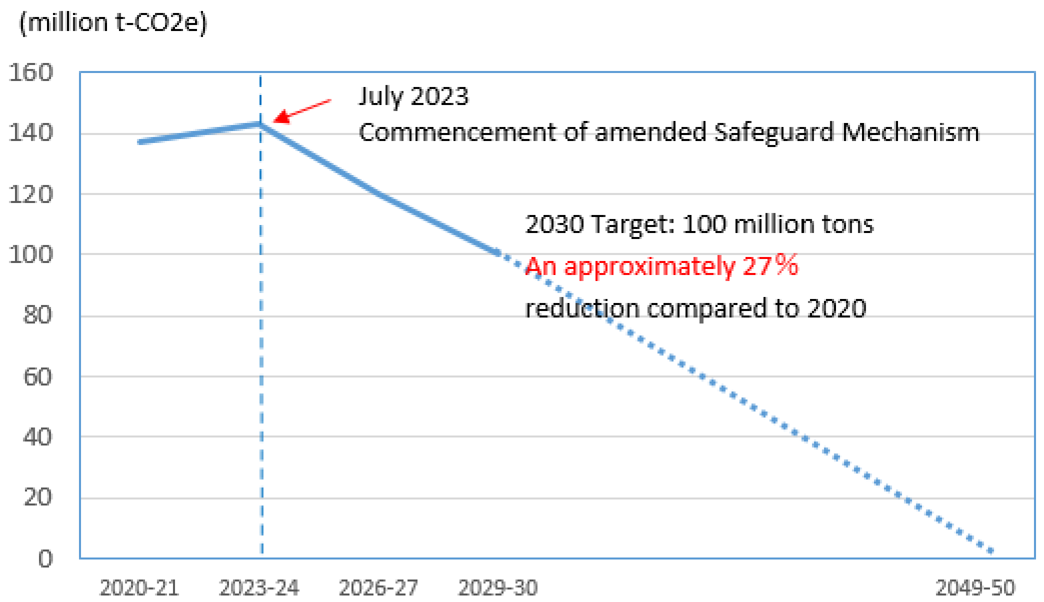

Figure 2 The Safeguard Mechanism's emissions reduction pathways toward 2050

(Source) Safeguard Mechanism Reforms Position Paper, DCCEEW (January 2023)

[1] https://storage.googleapis.com/files-au-climate/climate-au/p/prj2a056033efffb0b89f5fe/public_assets/Carbon%20leakage%20review%20-%20Consultation%20paper%201%20webinar%20slides.pdf

[2] The Australian government's national target for 2030 (a 43% reduction compared to 2005) corresponds to a reduction of approximately 28.9% compared to 2020, and so in pursuing a reduction matched to the national reduction target, a target of 99 million tons (a reduction level of around 28%) had been proposed. However, on the basis of industry views and other standpoints, this was eased slightly, to 100 million tons.

2.2. Approaches to Setting Target and Baseline

2.2.1. Baseline setting

A production-adjusted (intensity) baseline setting framework is used to calculate the permissible emissions values (caps) for greenhouse gas emitting facilities covered by the Safeguard Mechanism. The production-adjusted (intensity) baseline (hereinafter abbreviated to "baseline") is calculated by multiplying the quantity of activity, such as the quantity of key products produced, with the emissions intensity value (formula 1), and so as production volume increases or declines, so too does the baseline.

Production - adjusted (intensity) baseline = effective production x emissions intensity value x decline rate (Formula 1)

However, the emissions intensity values utilized in calculating the baseline differ for existing facilities and new facilities. In the case of existing facilities, up until 2030 it will be possible to use intensity values that combine the industry average intensity values with site-specific emissions intensity values (Table 1), but this will gradually shift from site-specific emissions intensity values to industry average intensity values. Furthermore, a decline rate of 4.9% per year applies to the baselines to 2030. This decline rate will be applied across the board to all facilities covered by the regulations, with no distinction made between new and existing facilities.[3] The decline rate from 2030 will be set every five years, and the decline rate up to 2035 is scheduled to be decided in July 2027.

On the other hand, in the case of new facilities,[4] "international best practice levels" will be applied as the intensity values to be used in calculating baselines. The Australian Government had begun exploring international best practice levels,[5] but in order to prevent distortions developing on the competition front between new and old, in cases where existing facilities manufacture new products it has decided to treat them as new facilities and apply international best practice levels.

Table 1 Ratios reflecting intensity values when calculating baselines of existing facilities

	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Industry average : Site-specific	10 : 90	20 : 80	30 : 70	40 : 60	60 : 40	80 : 20	100 : 00

(Source) Safeguard Mechanism Reforms Factsheet, DCCEEW (2023)[6]

2.2.2. Treatment of new gas fields

In calculating emissions targets for new facilities, international best practice levels will be used as the emissions intensity values. In particular, where new gas fields are concerned, because it is possible to utilize carbon capture and storage (CCS) the international best practice level will be set at "net zero." In June 2023, the Japanese government requested that the Barossa gas project be exempt due to uncertainty over whether it will be possible to supply the offset credits needed to offset the project's emissions, as well as concerns about the possibility of implementing CCS.[7] The Barossa gas field (ownership: JERA (12.5%), Santos (50%), SK E&S (37.5%)) is located in the waters off the Northern Territory. The plan calls for it to be connected to the Darwin LNG facility via a pipeline, with production commencing around 2025, CCS commencing from around 2027 and full-scale CCS implementation occurring in around 2030. According to analysis by Piers Verstegen and Rod Campbell (May 2023), the Barossa gas project is likely to incur carbon offset costs of between AUD500 million and AUD987 million, equivalent to around 20% of the project's capital cost (AUD5.2 billion).[8]

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3 The decline rate is eased for globally competitive companies.
4 Facilities that became covered by the scheme from July 1, 2021.
5 Public comment on international best practice benchmark guidelines was carried out in July-August 2023, with the development of benchmarks for key production items scheduled to begin at the end of 2023.
6 https://www.dcceew.gov.au/sites/default/files/documents/safeguard-mechanism-reforms-factsheet-2023.pdf
7 S&P Global (June 29, 2023) "Japan calls on Australia to exempt Barossa gas project from Safeguard Mechanism"
https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/lng/062923-japan-calls-on-australia-to-exempt-barossa-gas-project-from-safeguard-mechanism
8 The New Safeguard Mechanism and the Santos Barossa Gas Project, The Australia Institute; Piers Verstegen, Rod Campbell (May 2023)
https://australiainstitute.org.au/wp-content/uploads/2023/05/P1392-Barossa-Costs-Under-Safeguard-Mechanism-WEB.pdf

2.2.3. Treatment of the electricity sector

Where the electricity sector is concerned, a "sector baseline" is set as an emissions target for the sector as a whole, without emissions targets being set for individual electricity generating facilities. However, this will switch to regulations covering individual electricity generating facilities in cases where the overall electricity sector's emissions exceed this sector baseline. The emissions target for the electricity sector is set at 198 million t-CO_2e, which corresponds to the sector's maximum emissions from FY2009 to FY2013. The electricity sector's emissions have been declining from a peak reached in 2009, and as a result of growth in renewable energies in 2020, the sector's emissions were 172 million t-CO_2e, declining by around 20% compared to the 2005 level (Figure 3). According to the Australian government's national emissions forecast for 2030, the electricity sector's emissions will continue to decline, and are forecasted to fall to around 79 million t-CO_2e in 2030, a decline of around 60% compared to the 2005 level.[9] Because the electricity sector is already making progress with decarbonization in this way, the Safeguard Mechanism is not being employed to impose additional regulations on individual power plants.

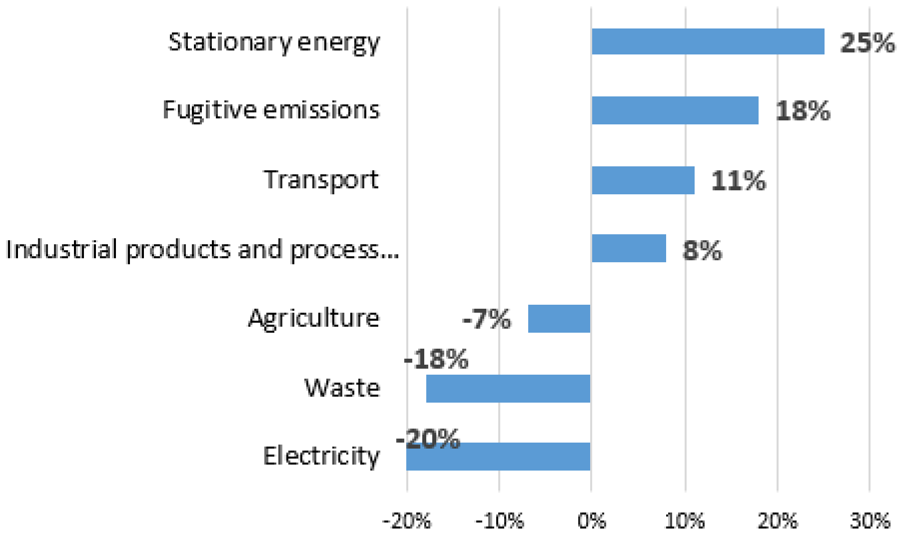

Figure 3 Changes in emissions covered by the Safeguard Mechanism (2005-2020)

(Source) Safeguard Mechanism Reforms Position Paper, DCCEEW (January 2023)

2.2.4. Measures to address carbon leakage

The Safeguard Mechanism incorporates measures for providing financial assistance and easing the burden of reducing emissions with the goal of ensuring that the domestic companies covered by the scheme are not disadvantaged on the global competitiveness front and that carbon emissions do not "leak" overseas. The facilities eligible for support are emissions-intensive, trade-exposed (hereinafter referred to as EITE) facilities, and these are divided into two categories: Trade Exposed facilities and Trade Exposed Baseline Adjusted (TEBA) facilities. Table 2 presents outlines and eligibility standards for the respective categories.

Table 2 EITE facility categories

	Outline	Eligibility standard
Trade Exposed facilities	Facilities whose main production variable is trade exposed	Trade share is 10% or above
Trade Exposed Baseline Adjusted (TEBA) facilities	Trade exposed facilities facing an elevated risk of carbon leakage	Scheme impact metric is 3% or above

(Source) Safeguard Mechanism Reforms Factsheet, DCCEEW (2023)

[9] DCCEEW (2022) Australia's emissions projections 2022
https://www.dcceew.gov.au/sites/default/files/documents/australias-emissions-projections-2022.pdf

Trade share is defined as the percentage of the trade value as a component of production value (Formula 2), and the scheme impact metric is defined as the percentage of the scheme cost as a component of revenue (Formula 3). Additionally, scheme cost is calculated by multiplying the excess emissions in the year in question by the default certificate price . The default certificate price (Formula 4) used for calculating the scheme cost will be published by regulatory authorities in June of each year.

Trade share	=	**(Import value + export value) ÷ domestic production value**	**(Formula 2)**
Scheme impact metric	=	**Scheme cost for a year ÷ revenue in that year**	**(Formula 3)**
Scheme cost	=	**Excess emissions x default certificate price**	**(Formula 4)**

Both EITE facility categories will be provided with subsidies toward investing in reducing their emissions through low-emissions technologies. Those subsidies will be provided through the Safeguard Transformation Stream, a dedicated fund worth around AUD600 million that forms part of the Powering the Regions Fund, which is worth around AUD1.9 billion in total. Additionally, industries (steel, cement, lime, aluminum, alumina etc.) that supply critical inputs to clean energy industries will be supported via the Critical Inputs Fund, which is worth around AUD400 million. However, coal and gas facility new builds and expansions fall outside the coverage of the Powering the Regions Fund.

The Safeguard Mechanism calls for an across-the-board decline of 4.9% per year from baseline emissions, but for TEBA facilities the burden of reducing emissions will be eased by applying a decline rate lower than 4.9%. The degree by which the decline rate is reduced will differ depending on factors such as the above-mentioned scheme impact metric, and whether the facility is in a manufacturing or non-manufacturing industry. In the case of the manufacturing industry, a decline rate lower than 4.9% will be applied in cases where the scheme impact metric is 3% or higher, and a minimal decline rate of 1% will be available at 10%. In cases where the scheme impact metric is between 3% or higher and does not exceed 10%, a graduated decline rate of between 1% and 4.9% will be applied. On the other hand, in the case of the non-manufacturing facilities, where the scheme impact metric is 3% or higher a decline rate of lower than 4.9% will be applied, and a minimum decline rate of 2% will be available at 8%. Incidentally, in cases where the scheme impact metric is between 3% and 8%, a graduated decline rate will be applied in line with the scheme impact metric. These measures ensure Australian industries remain on a fair competitive footing with industries overseas, but toward 2024 the Australian government was scheduled to consider whether leakage measures, such as a Carbon Border Adjustment Mechanism (CBAM), should be introduced in addition to the existing support policies.

2.3. Offset credits

Two credits can be utilized in the Safeguard Mechanism – Safeguard Mechanism Credits (hereinafter abbreviated as SMCs) and Australian Carbon Credit Units (hereinafter abbreviated as ACCUs).

SMCs are automatically issued when companies covered by the scheme generate fewer emissions than their facilities' reduction targets, and they can be used to comply with targets, or sold to other facilities, or banked. ACCUs are domestic offset credits issued for reductions arising from projects registered in the above-mentioned ERF. No limit is placed on offset credits when they are used to comply with targets, but if the quantity of ACCUs used exceeds 30% of a facility's baseline, the company must provide a statement explaining the reason why emissions were not reduced to the Clean Energy Regulator (hereinafter abbreviated as CER), the organization that implements and supervises the scheme. Incidentally, when both SMCs and ACCUs have been issued to Safeguard Mechanism-covered facilities participating in ERF projects, there is the potential for double counting to occur, and in order to avoid this, issuing ACCUs to Safeguard-covered facilities is prohibited. In the case of ERF projects currently being implemented, credits will be issued during the crediting period, but it has become impossible to enter new contracts (for government purchase of ACCUs) or extend their crediting periods, and an amount equivalent to the issued ACCUs is to be recorded in the net emissions of the facility in question.

Figure 4 shows the quantity of ACCUs issued by project type. Approximately 84.3 million tons of ACCUs were issued between 2018 and the second quarter of 2023, and looked at by project in descending order, vegetation accounted for 55.7%, followed by waste (28.1%), savanna fire management (9.1%), energy conservation (2.9%), leakage from industry (2.0%), and transport (0.1%).[10]

[10] Clean Energy Regulator's Quarterly Carbon Market Reports from 2018 to 2023
https://www.cleanenergyregulator.gov.au/Infohub/Markets/quarterly-carbon-market-reports

Looking at the data from 2018 to 2021 the main source of demand for ACCUs was ERF procurement.[11] ERF procurement refers to ACCUs bought up by the government from reduction projects that are selected in annual auctions held by the CER, based on the ERF's budget. Over the same period, demand arising from facilities covered by the Safeguard Mechanism regulations was around 1.4%. Other sources of demand include instances where ACCUs are purchased in order to make local and regional governments' independent programs compliant, and purchases and redemptions made voluntarily from an environmentally-oriented stance. (Figure 5).

Auctions were held by the ERF scheme a total of 15 times between April 2015 and March 2023, resulting in the selection of a total of 443 reduction projects. The total reduction anticipated from these reduction projects is 217.3 million t-CO_2e. The average contract price per ton of reduction in these reduction projects adopted as a result of the government's auctions is climbing, and is currently sitting at the AUD17 level. (Figure 6)

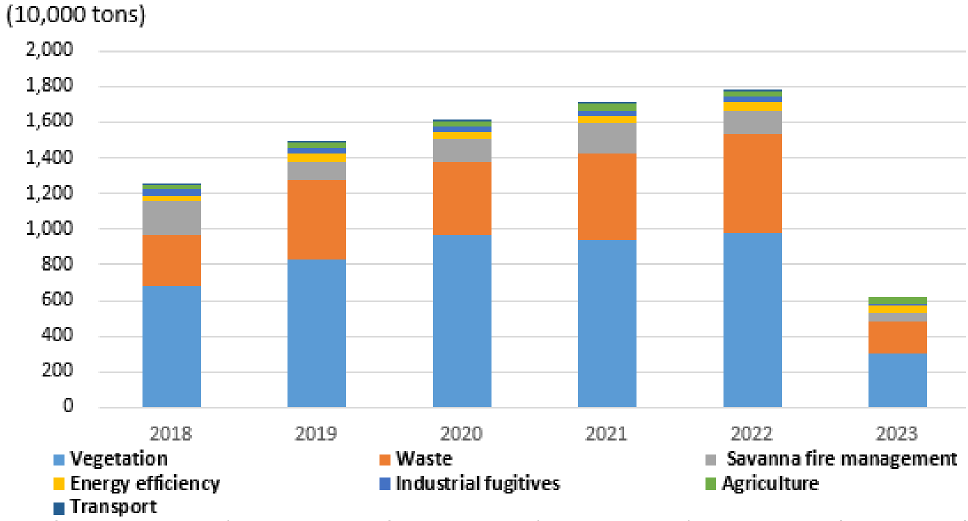

Figure 4 Quantity of ACCUs issued, by project type (2018-2023)

(Note) The 2023 figures are based on data up to the second quarter

(Source) Created using the Clean Energy Regulator's Quarterly Carbon Market Reports from 2018 to 2023

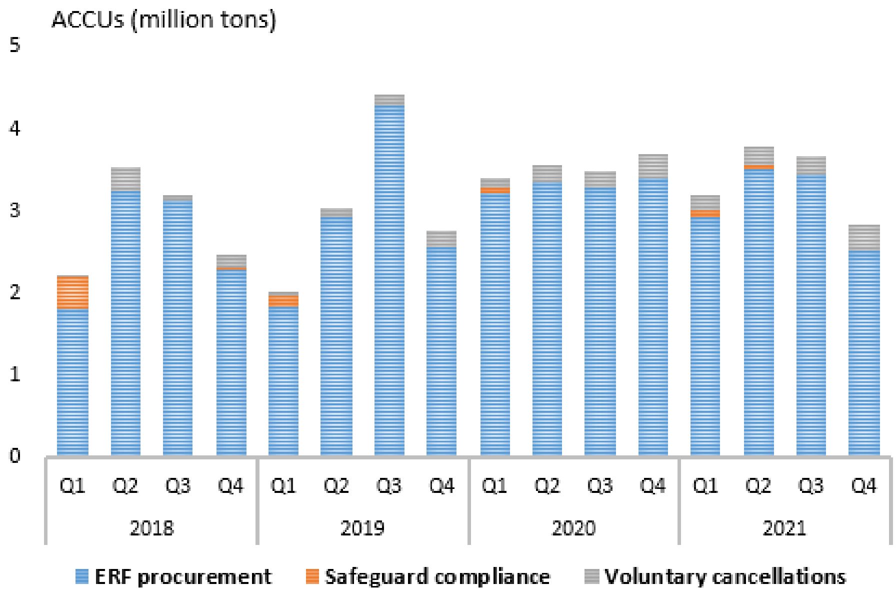

Figure 5 Breakdown and trends for ACCU demand (2018-2021)

(Note) ERF procurement indicates the procurement of ACCUs by the government from reduction projects selected in ERF auctions

(Source) Created using the Clean Energy Regulator's Quarterly Carbon Market Reports from 2018 to 2021

[11] Because ERF procurements and Safeguard Mechanism demand have not been disclosed since 2022, ACCU demand up to 2021 is shown.

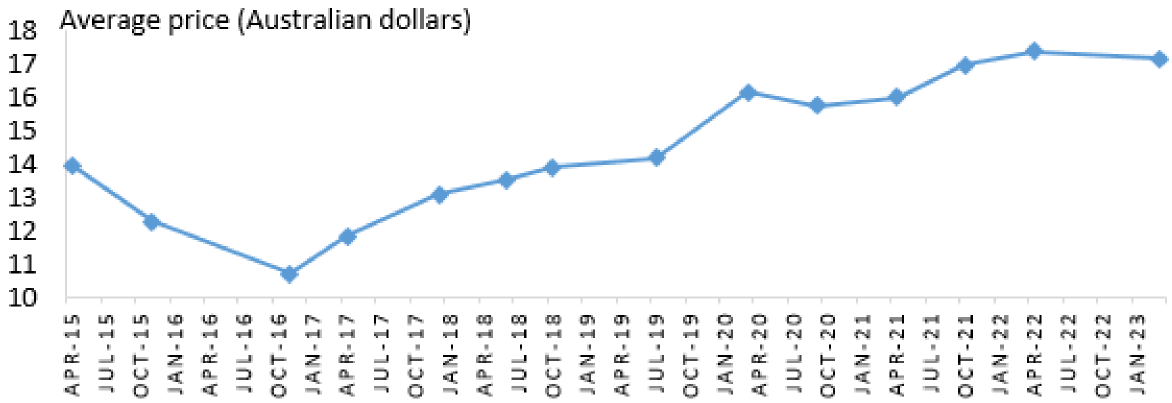

Figure 6 ACCU price trends in auctions (2018-2023)

(Source) Created using the Clean Energy Regulator's auction results for 2015-2023[12]

Figure 7 shows who among carbon market participants owns ACCUs.[13] Cumulatively, the quantity of ACCUs owned stood at around 27.6 million t-CO_2e in the second quarter of 2023, with ownership having increased by around 16.2 million t-CO_2e from 2022, when the bill to amend the Safeguard Mechanism was discussed, to 2023. By owner, brokers accounted for 35.3% of the ownership, followed by project participants (32.5%), companies (20.8%) and Safeguard-covered facilities (11.4%). Based on predictions that ACCU demand will grow in the future accompanying the amending of the Safeguard Mechanism, the quantity of ACCUs owned by brokers and companies and others outside the coverage of the Safeguard Mechanism is increasing. At the same time, up to 2020 the spot price of ACCUs had been sitting at the AUD16 level, but it climbed to AUD57.5 in January 2022 and hovered around the AUD30 level in 2023.

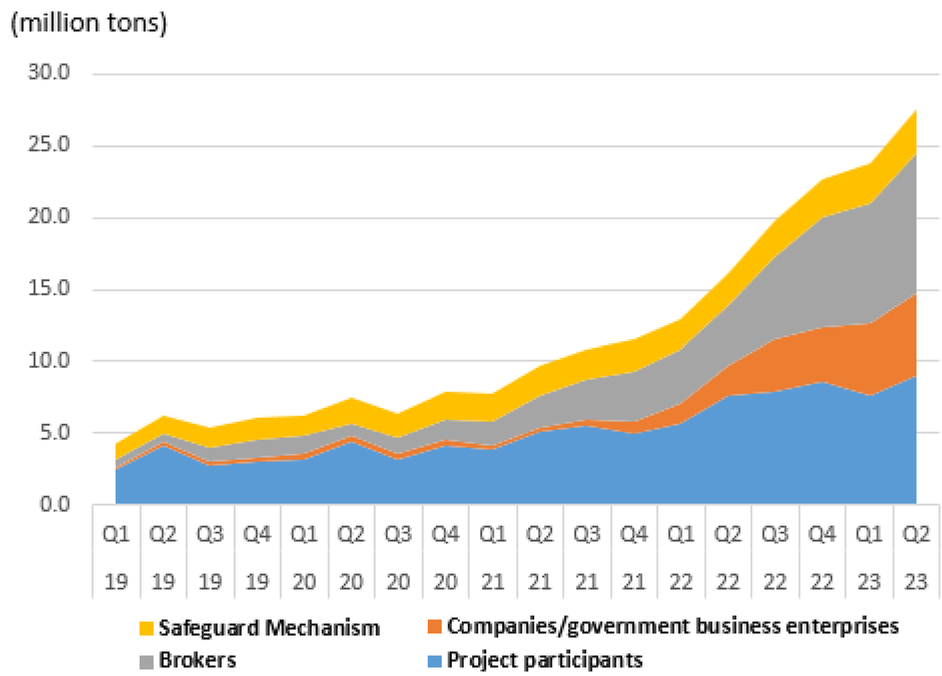

Figure 7 State of ACCU ownership (2019-2023)

(Source) Created using the Clean Energy Regulator's auction results for 2019-2023

[12] https://www.cleanenergyregulator.gov.au/ERF/auctions-results

[13] 2018 data on ownership by market participation was not available, so the figures for 2019 and beyond were compiled.

2.4. MRV of emissions

The calculation, verification and reporting to regulatory authorities of the emissions generated by companies covered by the regulations is carried out based on the provisions of the National Greenhouse and Energy Reporting (NGER) scheme. Table 3 presents an overview of the NGER scheme, while Table 4 presents the main schedule for the Safeguard Mechanism. Incidentally, the CER announces the results of Safeguard Mechanism companies' compliance, and information such as companies' emissions, baseline emissions, net emissions and offset credits used is made available to the public.

Table 3 Overview of the National Greenhouse and Energy Reporting scheme

Item	Outline
Law on which it is based	National Greenhouse and Energy Reporting Act 2007 (NGER Act)
Scheme outline	Makes it mandatory for companies to report their GHG emissions, energy production and energy consumption for a one-year period
Coverage (an entity is covered if even one of the criteria applies)	Facility standard: GHG emissions (scope 1 & scope 2) of 25,000 t-CO_2e or more, energy production of 100TJ or more, energy consumption of 100TJ or more Corporate group standard: GHG emissions (scope 1 & scope 2) of 50,000 t-CO_2e or more, energy production of 200TJ or more, energy consumption of 200TJ or more
Matters to be reported	Matters that are reported include emissions (scope 1, scope 2), energy production and energy consumption
Public disclosure of information	The information that is publicly disclosed includes companies' total GHG emissions, energy used, electricity generated at each power station, emissions (total quantity, scope 1, scope 2), emissions intensity values, whether or not companies are connected to the grid, and primary fuel sources
Standard for disclosure	Companies that have overall GHG emissions (scope 1 + scope 2) of 50,000 t-CO_2e or more
Reporting deadlines	Companies report the relevant data by the end of October each year (see note), while the regulatory authority (the CER) makes the information publicly available at the end of February each year

(Note) Companies with emissions of one million t-CO_2e or more are required to submit an auditing report

(Source) Created by the author based on the Clean Energy Regulator (CER)'s website,[14] National Greenhouse and Energy Reporting Act 2007 and other information

Table 4 Main schedule for the Safeguard Mechanism

Deadline	Content
June 30	Deadline for scheme compliance
October 31	Deadline for reporting (emissions, production) and EITE applications
November 15	Deadline for applying for multiyear monitoring
January 31	Issuance of SMCs
February 28	Deadline for borrowing applications
March 31	Deadline for submitting ACCUs and SMCs

(Source) Safeguard Mechanism Reforms Factsheet, DCCEEW (2023)

[14] "About the National Greenhouse and Energy Reporting scheme," Clean Energy Regulator (CER) https://www.cleanenergyregulator.gov.au/NGER/About-the-National-Greenhouse-and-Energy-Reporting-scheme

2.5. Relationship with other policies

The Safeguard Mechanism, which makes it legally mandatory to hold emissions below permissible emissions values, was introduced as one part of the ERF scheme (designated the ACCU scheme from October 2023). The main constituent elements of the ERF scheme are the three safeguards of crediting, trading and emissions reduction. Initially, the purpose of the Safeguard Mechanism was to supplement the ERF scheme by ensuring that companies' emissions did not exceed BAU levels, but it was reformed in a way that strengthened its links to Australia's greenhouse gas reduction targets. Incidentally, the Safeguard Mechanism is executed and administered by the National Greenhouse and Energy Reporting (NGER) scheme, and the offset credits utilized in complying with the scheme conform to the Carbon Credits (Carbon Farming Initiative) Rule 2015 and the Australian National Registry of Emissions Units Regulations 2011.

3. Implications for the GX-ETS

The characteristic points of Australia's Safeguard Mechanism from a design perspective are: 1) there is no pre-allocation of emission allowances; 2) the permissible emissions values (caps) of facilities covered by the Safeguard Mechanism rise and fall in line with rises and falls in their production; 3) it is possible to opt for multiyear monitoring; 4) effectively, the electricity sector is not covered by the regulations; and 5) the standards for new facilities are extremely strict. 1) and 2) can be thought of as measures aimed at preventing (from a scheme design perspective) surplus emission quotas from emerging wherever possible. 3) is a measure that grants flexibility to companies, and 4) reflects the current state of the electricity sector, which is moving ahead with reducing emissions even without additional measures being imposed.

5) will be the measure that attracts attention in terms of its implementation going forward. International best practice levels will be demanded of new facilities, including a net zero requirement for new gas fields, and furthermore, annual reductions of 4.9% per year from international best practice levels are being sought. If the standards applied to new facilities are too strict, from a company's standpoint it will be necessary to be cautious about investing in new facilities, and conceivably one outcome of that could be that the lifespans of old, inefficient facilities end up being extended. The future of decisions on and management of international best practice levels, and how scheme design can prevent such concerns from 2030 and beyond, will be a major focus.

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[3] National Greenhouse and Energy Reporting (Safeguard Mechanism) Amendment (Reforms) Rules 2023, Australian Government Federal Register of Legislation
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Appendix Overview of Australia's Safeguard Mechanism

Overview	Name	The Safeguard Mechanism
	Legal basis (names of laws)	・Safeguard Mechanism (Crediting) Amendment Act 2023 ・National Greenhouse and Energy Reporting (Safeguard Mechanism) Amendment (Reforms) Rules 2023 ・Carbon Credits (Carbon Farming Initiative) Amendment (No. 2) Rules 2023 ・Australian National Registry of Emissions Units Rules 2023
	Overview	Domestic emissions trading scheme covering the mining, petroleum and gas production, manufacturing, transport and waste sectors
	Supervisory authority	Clean Energy Regulator
	Time when scheme commenced	From 2016 (amended scheme commenced from July 1, 2023, reviewed every five years)
Coverage	Unit	Facility unit
	Requirements of main parties covered	Facilities with scope 1 emissions of 100,000 t-CO_2e or more in a one-year period
	Gases covered	Six greenhouse gases (CO_2, CH_4, N2O, HFCs, PFCs, SF_6)
	Emission points (direct / indirect)	Direct emissions (scope 1 emissions)
	Coverage	Approximately 28% of national emissions (approximately 215 large-scale facilities)
Method for setting targets	Allocation method	・ For existing facilities, baseline values will be calculated by multiplying intensity values (which combine their industry average intensity values with site-specific emissions intensity values) by production activity, and a decline rate of 4.9% per year will then be applied to those baselines ・ For new facilities, baseline values will be calculated by multiplying the emissions intensity values of international best practices with production activity, and a decline rate of 4.9% per year will then be applied to those baselines

Flexibility measures	Banking / Borrowing	・ No limits on banking until 2030. Safeguard Mechanism Credits (SMCs) can be used for scheme compliance irrespective of the year they were issued. The decision on their use from 2030 will be decided when the scheme is reviewed in 2026-27 ・ Possible to borrow up to 10% of baselines until 2030 (once borrowed, interest of 10% per annum is incurred. However, the interest rate for the initial two years is 2%)
	Utilization of other credits	・ In cases where facilities covered by the scheme generate fewer emissions than their baselines they are automatically issued with Safeguard Mechanism Credits (SMCs). SMCs can be redeemed for the purposes of scheme compliance, sold to other entities or banked. ・Australian Carbon Credit Units (ACCUs) can be utilized. At the present point in time, it is not possible to use overseas credits.
	Pricing measures (setting of upper and lower price limits, market monitoring mechanism)	・ Only those facilities whose emissions exceed their baselines are able to buy ACCUs from the government at a fixed price ⇒ AUD75 in 2023-24; the fixed price will be raised by the CPI plus 2% each year
	Measures for mitigating burden/leakage	・Trade Exposed facilities will be supported with subsidies toward investing in emissions reduction via the Safeguard Transformation Stream, a dedicated fund worth around AUD600 million that forms part of the Powering the Regions Fund (PRF) ・The baseline decline rate will be eased for Trade Exposed Baseline Adjusted (TEBA) facilities
Market	Links with other schemes (under consideration)	—
	Register / MRV method	Based on Greenhouse and Energy Reporting (NGER) scheme
	Sequence of events to introduction (discussion leading up to introduction, explanation of differences between initial proposal and final scheme)	・ The Safeguard Mechanism scheme introduced in 2016 was amended accompanying the strengthening of Australia's 2030 national reduction target, emissions targets for the scheme have been set, and companies' caps are also being bolstered.
Penalties	Compliance costs	・Compulsory fulfilment, infringement notification, suspension orders from the courts, fines etc. ・Originally, fines were based on the number of days of non-compliance rather than the size of the excess emissions, but this has been revised into a format that is connected to the size of the excess emissions [Concept underlying fines] Penalty = 1 penalty unit x number of tons of excess emissions ・The number of tons of excess emissions is the difference between a facility's net emissions over a monitoring period (normally a period of one year) and its baseline emissions. One penalty unit is AUD275.

(Source) Created by the author from various documents

California's Cap-and-Trade Program

Asamu Ogawa*, Tohru Shimizu**

1. Climate change policy outline

California has implemented a wide range of programs that leverage advanced markets, such as the Renewables Portfolio Standard, the Low Carbon Fuel Standard, and zero-emission vehicle (ZEV) regulations. Among them is the Cap-and-Trade Program.

The decision to introduce the program came under the Global Warming Solutions Act of 2006 (AB-32),[1] which stipulates measures against global warming through 2020. AB-32 aims to reduce California's emissions to 1990 levels by 2020 and positions the program as a key policy tool to achieve this target. The program was launched in 2013. A wide range of business operators, including large emitters such as power generators, and fuel suppliers, are subject to the program.

In July 2017, the California Legislature passed a law (AB-398[2]) to revise the emissions trading system and implement it beyond 2020 until 2030. AB-398 stated that the State of California Air Resources Board (CARB) would decide on specific implementation methods and rules (such as specific maximum prices). CARB considered them in 2018 and decided on them in December 2018.

Apart from the consideration, the Independent Emissions Market Advisory Committee (IEMAC),[3] established under AB-398, analyzed issues regarding the program. It was then found that there were massive surplus emission allowances that were hindering the efforts of regulated companies to reduce emissions.

In light of the finding, CARB considered an initiative to monitor surplus emission allowances from 2020, in addition to the specific implementation methods and rules of AB-398 decided on in 2018.

2. Emissions trading program design

2.1. Overview of the program

California's Cap-and-Trade Program annually lowers the regulatory cap on emissions to reduce greenhouse gas emissions in the state. The Cap-and-Trade program is an important part of measures to achieve the state's GHG emissions reduction target,[4] covering about 75% of California's GHG emissions.

The Californian Cap-and-Trade Program features cooperation with a foreign local government cap-and-trade system. While negotiations on the formulation of rules for the international transfer of emissions based on the Paris Agreement are still underway, California has been cooperating with the Canadian province of Quebec in regard to emissions trading since 2014.

Figure 1 shows the trends of auction settlement and reserve prices under the Cap-and-Trade Program. Until mid-2021, auction settlement prices had generally remained close to reserve prices. In the second quarter of 2021, the auction settlement price was \$17.84/t-CO_2e or almost equal to the reserve price at \$17.71/t-CO_2e. One of the reasons why settlement prices were close to reserve prices is that the emission allowance supply apparently far exceeded demand as (1) allowances for paid allocation and (2) allowances for financing demand-side initiatives for the electrical utility sector are sold simultaneously in each auction. On the other hand, the auction settlement price continued to increase from the third quarter of 2021 and reached \$38.73/t-CO_2e, far above the reserve price of \$22.21/t-CO_2e in the fourth quarter of 2023. There was a view that the increase in the auction settlement price reflected the anticipation of growing demand for emission allowances in the future. There were no specific factors such as the enhancement of emission reduction targets or the revision of the program.

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1 AB-32 Air pollution: greenhouse gases: California Global Warming Solutions Act of 2006. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200520060AB32

2 AB-398 California Global Warming Solutions Act of 2006: market-based compliance mechanisms: fire prevention fees: sales and use tax manufacturing exemption. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180AB398

3 Independent Emissions Market Advisory Committee (IEMAC) https://calepa.ca.gov/independent-emissions-market-advisory-committee/

4 California has developed a comprehensive plan known as the Scoping Plan to achieve its GHG emissions reduction target. The 2017 Scoping Plan estimated the GHG emission reduction for each policy measure from 2021 to 2030. The estimate indicates that various policy measures are expected to reduce emissions by a total of 622 million tons CO_2 equivalent. The Cap-and-Trade Program is estimated to account for the largest share, at 236 million t-CO_2e, or 38% of the total reduction.

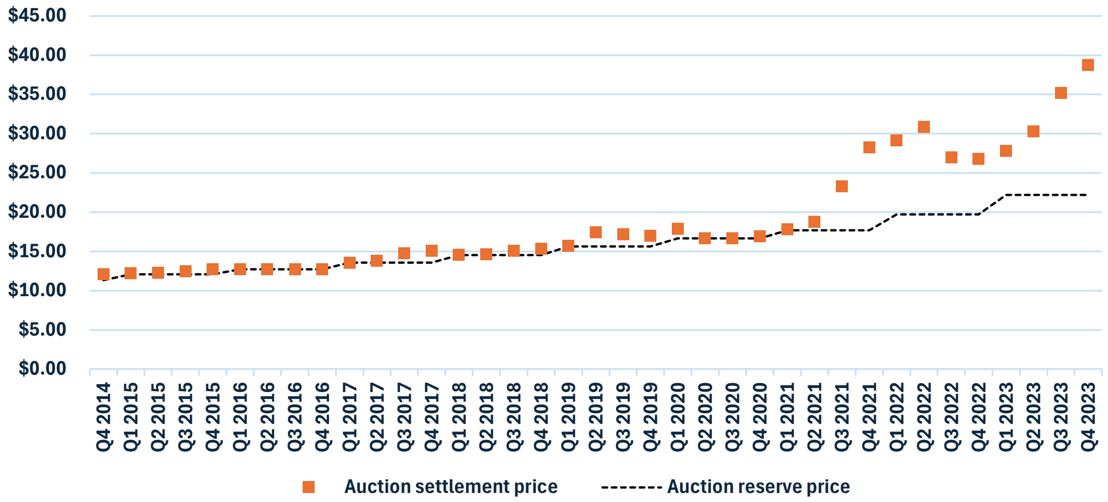

Figure 1 Auction settlement and reserve price trends

Source: CARB

An interesting aspect of California's climate change policy is that it has a mechanism to pass government costs for climate change policy measures such as the Cap-and-Trade Program on to business operators. In September 2009, CARB adopted the Cost of Implementation Fee Regulation[5] to pass costs for Cap-and-Trade Program operations under AB-32 on to business operators. Under this regulation, about 250 companies, including natural gas suppliers, gas pipeline operators, transport fuel manufacturers and importers, cement manufacturers, and electrical utilities, shouldered Cap-and-Trade Program operation costs according to CO_2 emissions and other factors.

2.2. Allocation method (paid and free)

California's Cap-and-Trade Program combines free emission allowance allocations to the industrial sector, those to the electrical utility sector through auctions to finance energy efficiency improvement, and paid allocations to the industrial and electrical utility sectors through auctions. Figure 2 shows the allocation plan through 2030.

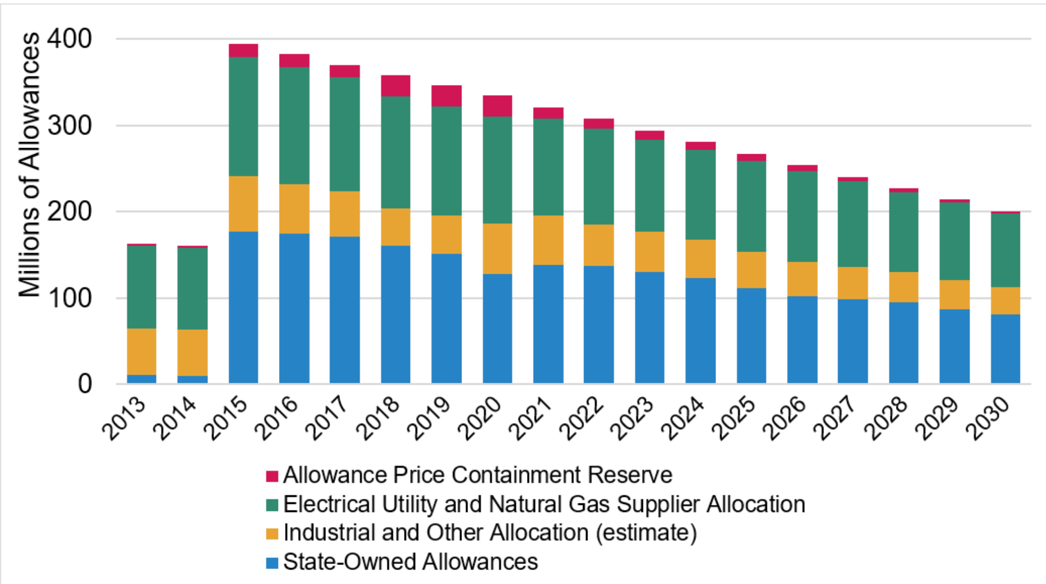

Figure 2 Emission allowance allocation plan though 2030

Source: CARB

[5] Cost of Implementation Fee Regulation
https://ww2.arb.ca.gov/our-work/programs/ab-32-cost-implementation-fee-regulation

In the industrial sector, there are 85 product-specific benchmarks for 34 high-emission industries, including crude oil extraction, natural gas extraction, mining, paper manufacturing, industrial gas production, fertilizers, ceramics, cement, steelmaking, and oil refining. The benchmarks are based on the average data for the top 10% in each industry from 2008 to 2010. Free emission allocations are determined after these benchmarks are adjusted by the carbon leakage risk factor and the cap adjustment factor consistent with the 2030 emission reduction target (for the "Industrial and Other Allocation (estimate)" in the above figure). The free allocations are determined in advance before the allocation plan period (about three years). If there are changes in production during the allocation plan period, a mechanism may be used to adjust allocations in the final year of the period. For industries that are not subject to the benchmarks, free allocations are made based on a uniform emission factor.

In order to mitigate the impact of the Cap-and-Trade Program on consumers, emission allowances based on customers' carbon reduction compliance costs shouldered by electrical utilities are allocated free of charge to the electrical utility sector and sold on the market to implement equivalent emission reduction measures such as thermal insulation of houses and the introduction of renewable energy (Electrical Utility and Natural Gas Supplier Allocation in the above figure). Allowances for the free allocation are calculated by adding up electricity sales supplied through coal and natural gas power generation, excluding sales supplied to the industrial sector subject to the Cap-and-Trade Program that are covered by allowances for the paid allocation through auctions. Power utilities are required to use profits from allowance sales to implement measures such as subsidies for energy-saving products for customers, insulation retrofit, and renewable energy introduction and report their results converted into CO_2 equivalent to CARB in line with a guidance.[6]

Paid allowances ("Electrical Utility and Natural Gas Supplier Allocation" and "State-Owned Allowance" in the above figure) are allocated through quarterly auctions (in February, May, August, and November) for both the industrial and electrical utility sectors. Auctions for the free allocation of allowances to the electrical utility sector coincide with the quarterly auctions for the paid allocation. Based on AB-398, the maximum prices (Allowance Price Containment Reserve prices) and the minimum price (Auction Reserve price) are set for auctions.

Under the maximum price mechanism that was introduced in 2020, when bid prices reach a certain level, an additional auction for business operators is conducted. Additional allowances supplied for the additional auction are partly reserved in advance in the Allowance Price Containment Reserve account managed by CARB. When setting the maximum prices, CARB considers the following points and publishes the prices annually:[7]

- The need to avoid negative consequences for households, businesses, and the economy of the state
- Potential leakage
- Latest auction prices
- Social costs of GHG emissions
- Costs to meet the state's emission reduction target

There are three maximum prices: two fixed prices (Tier 1 and Tier 2) and a price ceiling. For 2024, Tier 1 is set at \$56.20/t-CO_2, Tier 2 at \$72.21/t-CO_2, and the price ceiling at \$88.22/t-CO_2. Business operators that fail to secure allowances required for carbon reduction compliance may obtain the necessary allowances by participating in a third-quarter auction conducted by CARB before the November compliance deadline. For auctions regarding the maximum prices, emission allowances are reserved for each maximum price. If emission allowances reserved for the lowest maximum price of Tier 1 are exhausted, those for the next lowest price of Tier 2 may become available and then those for the price ceiling.

The minimum price has been set since the commencement of the Cap-and-Trade Program. If bid prices fall below the minimum level, the relevant auction may be unsuccessful. For 2024, the minimum price is set at \$22.21/t-CO_2. It is adjusted in line with the annual inflation rate.

2.3. Availability of offset credits

The Cap-and-Trade Program allows CARB-approved offset credits to be used for emission reduction compliance measures. Offset credits are limited to Californian or U.S. domestic projects for the following categories:

- Forests

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[6] Guidance on Electrical Distribution Utilities and Natural Gas Suppliers Use and Reporting of Allocated Allowance Auction Proceeds https://ww2.arb.ca.gov/sites/default/files/cap-and-trade/guidance/edu_ngs_allowance_value_guidance.pdf

[7] Cost Containment Information https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/cost-containment-information

- Agriculture/livestock
- Ozone-depleting substances
- Methane recovery in mining
- Limit on available offset credits

There is a cap on offset credits that can be used for emission reduction compliance measures, standing at 4% for 2021-2025 and 6% for 2026-2030. During the 2018-2020 compliance period, approximately 7% of the emission allowances used for compliance came from offset credits (an offset credit cap was 8%).

2.4. MRV

California's Mandatory GHG Reporting Program is used for the measurement, reporting, and verification (MRV) of GHG emissions and removals. The program was launched in 2007 and covers manufacturers, fuel and natural gas suppliers, and electricity suppliers that have facilities with emissions of 10,000 t-CO_2e or more. It covers 80% of California's emissions. Third-party verification is mandatory for facilities with 25,000 t-CO_2e or more in emissions that are subject to the Cap-and-Trade Program. CARB has developed a program that refers to ISO 14065 and other standards (for accreditation of greenhouse gas validation and verification bodies) and certifies verification organizations.

Business operators subject to the Cap-and-Trade Program are required to calculate their emissions from January to December each year, present third-party-verified emissions performance reports to CARB by August 12 of the following year, and submit the necessary emission allowances by November 1. In the first and second years of the three-year plan period, however, they are required to submit emission allowances for at least 50% of actual emissions. After the end of the plan period, they may submit allowances for their accumulated emissions to complete their compliance measures.

2.5. Relations with other policies

Auction proceeds are managed as the Greenhouse Gas Reduction Fund (GGRF) established by the state government. They are used for the following purposes that directly or indirectly contribute to the reduction of GHG emissions in the state:

- Improvement of the state's economy, environment, and public health
- Improvement of air quality
- Mitigation of the effects of climate change in the state
- Support for impoverished communities and families in the state

In California, how to use auction proceeds is decided through an annual state budget (spending plan) that is approved by the state legislature and signed into law by the governor. More than 73% of such proceeds are spent for low-income earners and other people vulnerable to climate change damage due to the enactment of regulations that require at least 35% of such proceeds to be spent on such people.

3. Implications for GX ETS

The implications of the Californian Cap-and-Trade Program for Japan's Green Transformation Emissions Trading System, known as GX-ETS, include measures to operate the system sustainably. While how to design an ETS system including emission allowance allocation methods and price fluctuation countermeasures is important, measures to sustainably operate the system are significant for designing the system. Such measures are (1) financing, (2) MRV operation, and (3) consideration to households.

Regarding financing, California collects costs from energy-intensive industries for operating climate change measures such as the Cap-and-Trade Program. Japan should consider collecting funds from business operators subject to the GX ETS for a budget of the GX Promotion Organization as the GX ETS operator to secure the sustainability of the system.[8]

Coming next is the operation of the MRV. Six years before the Cap-and-Trade Program went into operation, California introduced a GHG reporting system that requires third-party verification. It also used data collected through the reporting system for designing the Cap-and-Trade Program, giving consideration to reducing MRV burdens on companies. In Japan, companies report energy consumption and GHG emissions

[8] If operating funds are to be raised separately, targets to be achieved under the GX ETS should be clarified along with the timing for its abolition.

under the Act on the Rational Use of Energy and the Act on Promotion of Global Warming Countermeasures. The reporting systems under the two acts require no third-party verification,[9] unlike the Californian GHG reporting system. At least the third-party verification may be inevitable for the GX ETS MRV. Although the reporting systems under the two acts have different organizational boundaries with the GX ETS MRV, it has been suggested that a GHG emission calculation method under the Act on Promotion of Global Warming Countermeasures be utilized for the GX ETS. Therefore, a mechanism should be developed to take advantage of an electronic reporting system for the existing reporting systems to reduce MRV burdens on companies for the GX ETS.

Lastly, consideration should be given to households. California's Cap-and-Trade Program requires at least 35% of auction proceeds to be spent for low-income and other communities and populations vulnerable to climate change damage. Furthermore, the electrical utility sector uses proceeds from the sale of emission allowances allocated free of charge at auctions to introduce energy-saving products and renewable energy for households and renovate their thermal insulation. In Japan as well, some burden reduction measures linked to the GX ETS will be required for households, although specific measures need to be examined. Such burden reduction measures should be considered to increase the social acceptability of the GX ETS.

In this way, the design of the GX ETS should be discussed along with financing, social acceptability, and other matters to sustainably operate the GX ETS.

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[2] State of California Air Resources Board (2017) "California's 2017 Climate Change Scoping Plan"
https://ww2.arb.ca.gov/sites/default/files/classic/cc/scopingplan/scoping_plan_2017.pdf

[9] Even in cases where no third-party verification is required, there are mechanisms to verify the quality and validity of data. For example, a mechanism to secure the quality and validity of data under the Act on the Rational Use of Energy and the Act on Promotion of Global Warming Countermeasures includes verification with an online system called the Energy Efficiency and Global Warming Countermeasures online reporting System, or EEGS, and checks by Regional Bureaus of Economy, Trade and Industry. Similarly, the U.S. Environmental Protection Agency's Greenhouse Gas Reporting Program (GHGRP) requires no third-party verification, depending on checks by the system and relevant divisions for securing the quality and validity of data.

Europe Wavers on Reaching their Decarbonization Targets

Kei Shimogori *

Since the Russian invasion of Ukraine, global policy emphasis has been placed on energy security, or specifically, securing energy supply and responding to rising prices. Various nations in Europe have been aiming to move away from fossil fuels sourced from Russia, while tackling the rising energy prices by implementing such measures as reducing energy related taxes, regulating retail pricing, and adding windfall taxes. Despite this situation, the EU and the UK have been maintaining their long-term decarbonization goals (to achieve climate neutrality by 2050), and in Europe specifically, the revision of regulations and directives for achieving their 2030 greenhouse gas emission targets (a minimum 55% reduction over 1990 levels by 2030) has largely been enacted. However, dissatisfaction and concern over rising prices (increased economic burden) among citizens, industry, and farmers are simultaneously rising. Consequently, the content of policy geared towards decarbonization targets is being reviewed in each country in light of that dissatisfaction and concern.

Examples of this trend include the UK and Germany. Prime Minister Sunak in the UK announced in September 2023 that policy for achieving Net Zero by 2050 would be revised in order to reduce the economic burden to families.[1] The revisions included such changes as a five-year delay of the ban on sales of new gasoline and diesel automobiles, the delay of the ban on new installations of oil and LPG boilers and coal heating for off-gas-grid homes until 2035 (but with phase-out from 2026), and the establishment of exemptions to the phase-out of fossil fuel boilers, including gas boilers, beginning in 2035. The UK achieved a 49% reduction in greenhouse gas emissions over 1990 levels in 2022, and the Prime Minister decided to revise policy from the standpoint of economic burden, which is of great interest to citizens, after determining that the UK would still be able to comply with international commitments.[2] However, regarding this policy change, the UK Climate Change Committee has pointed out that no evidence to back the Government's assurance has been offered that the 2030 reduction goals in particular (a 68% reduction over 1990 levels) will be met, and that there is a major policy gap in terms of achieving that goal.[3]

Meanwhile, in Germany, revisions to the Building Energy Act passed the Bundestag in September 2023, but there was great difficulty during the process from the proposed amendment in April to its passing. The original proposal called for the elimination of fossil fuel-based boilers in 2024, and a mandate that new heating installation must use 65% or more renewable energy from January 1, 2024. However, due to partisan conflict, including within the coalition government, over the cost of heating equipment, the end, it was decided to extend that deadline to 2028 pending the preparation of municipal heating plans for existing buildings and new construction outside new development regions (with specific deadlines set to the end of June 2026 or the end of June 2028 depending on the size of the municipality), and to allow the installation of heating systems that do not meet the 65% requirement until that deadline.[4]

In addition to this, protests by farmers have recently been spreading throughout the EU member states[5], in both the east and west, and the impact thereof is garnering attention. While the focus of protests varies depending on the country, issues include cheap imports from outside the region (the influx of Ukrainian agricultural products thanks to the establishment of alternative export routes and the move toward the Southern Common Market free trade agreement with southern South America, or MERCOSUR), excessive regulations and bureaucracy at the EU level, and rising energy prices (including the reduction of subsidies for diesel fuel). For example, the federal government in Germany proposed the

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1 Prime Minister's Office, "PM recommits UK to Net Zero by 2050 and pledges a "fairer" path to achieving target to ease the financial burden on British families", 20 September 2023, <https://www.gov.uk/government/news/pm-recommits-uk-to-net-zero-by-2050-and-pledges-a-fairer-path-to-achieving-target-to-ease-the-financial-burden-on-british-families>.

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3 Climate Change Committee, "CCC assessment of recent announcements and developments on Net Zero", 12 October 2023, <https://www.theccc.org.uk/2023/10/12/ccc-assessment-of-recent-announcements-and-developments-on-net-zero/>.

4 Bundesministerium für Wirtschaft und Klimaschutz, "Startschuss für klimafreundliches Heizen: Bundestag beschließt Novelle des Gebäudeenergiegesetzes", 8 September 2023, <https://www.bmwk.de/Redaktion/DE/Pressemitteilungen/2023/09/20230908-bundestag-beschliesst-novelle-des-gebaeudeenergiegesetzes.html>.

5 Countries including Belgium, France, Germany, Greece, Hungary, Italy, Latvia, Lithuania, Netherlands, Poland, Spain, and Romania.

immediate elimination of tax incentives for agricultural diesel fuel during the review of the 2024 budget[6], but shifted to a phased reduction and elimination by 2026 after fierce opposition. Meanwhile, the French government withdrew a proposal to reduce subsidies for agricultural fuel at the end of January 2024.

Protests by farmers resulted in the withdrawal or revision of policy proposals not only at the member state level, but at the EU level as well. The European Commission proposed a one-year extension to the temporary suspension of import duties on Ukrainian agricultural products in January 2024, but with the assumption of an emergency brake to stabilize imports of chicken, eggs, and sugar, products particularly affecting member states, at the average import volume from Ukraine in 2022 and 2023.[7] On the same day, the European Commission proposed an exemption from the Common Agriculture Policy (CAP). The CAP is a comprehensive policy common to the EU region that aims to achieve a stable food supply, assurance of farmer income, environmental protection, and rural development. The existing CAP (covering 2023 through 2027) mandates that 4% of farmland must remain fallow, but the European Commission proposed a one-year exemption to that mandate beginning at the start of 2024.[8] The requirement would be met by using 7% of farmland for growing nitrogen-fixing crops and/or intercrops.

Meanwhile, in February 2024, the European Commission announced the withdrawal of the Sustainable Use Regulation (SUR) aimed at reducing the use of chemical pesticides by half by 2030.[9] The SUR was proposed by the European Commission in June 2022 as part of the Farm to Fork strategy under the European Green Deal. Designed to build a more sustainable food system, it would have been a change from the existing directive on the sustainable use of pesticides to a regulation and included the imposition of binding reduction targets for member states. However, the draft regulation was rejected[10] by the European Parliament in November 2023, and ultimately withdrawn when no progress was made in discussions by the Council of the European Union. The Agriculture and Fisheries Council confirmed the political will to effectively respond to the concerns of farmers when they met at the end of February 2024. They welcomed the recent agriculture related decisions by the European Commission and reached agreement on short-term responses, including the simplification of complicated requirements and testing methods previously proposed by the Commission, while offering political guidance on the mid- to long-term approach.[11]

Furthermore, in February 2024, the European Commission recommended[12] a target of 90% reduction in greenhouse gasses over 1990 levels by 2040 and expressed that one of the requirements for achieving that target was strategic dialog on a post-2030 framework, including the industrial and agricultural sectors. However, the recommendation only called for the agricultural sector to play a role in the green transition like other sectors[13], and no specific numerical target was expressed in light of the farmer protests.

2024 will be an important election year for Europe (both EU and UK). EU Parliament elections are expected for June 2024, while a general election is expected to be held in the UK in the latter half of the same year. In the Netherlands, the Farmer–Citizen Movement (BoerBurgerBeweging or BBB) gained the support of farmers in the provincial elections in 2023 by criticizing the government's climate change policy (the reduction of nitrogen emissions by half by 2030), becoming the leading party in almost every province and in the Senate. Meanwhile, it has been reported that far-right forces have been taking advantage of the spread of farmer protests. One example of this is the AfD in Germany. According to a report published in February 2024 by the European Committee of the Regions (CoR), there is a strong tendency for rural voters to support and drive Euroskeptic parties in countries that tend to vote for Euroskeptics (particularly Hungary, Poland, and Italy), and their anti-EU rhetoric has succeeded in reflecting their concerns and priorities during major national elections.[14] It is yet unclear to what extent the far-right will

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6 The Federal Constitutional Court determined in November 2023 that the application of an unused amount of 60 billion euros, left over from the budget for measures against COVID-19, for use as a climate change fund, was unconstitutional. As a result, the federal government was forced to review its 2024 budget. The Bundestag and the Bundesrat ultimately passed the 2024 budget in February 2024.

7 European Commission, "EU reaffirms trade support for Ukraine and Moldova", 31 January 2024, <https://ec.europa.eu/commission/presscorner/detail/en/IP_24_562>.

8 European Commission, "Commission proposes to allow EU farmers to derogate for one year from certain agricultural rules", 31 January 2024, <https://ec.europa.eu/commission/presscorner/detail/en/ip_24_582>.

9 Olivia Gyapong, "EU Commission chief to withdraw the contested pesticide regulation", EURACTIV, 6 February 2024, <https://www.euractiv.com/section/agriculture-food/news/von-der-leyen-to-withdraw-the-contested-pesticide-regulation/>.

10 European Parliament, "No majority in Parliament for legislation to curb use of pesticides", 22 November 2023, <https://www.europarl.europa.eu/news/en/press-room/20231117IPR12215/no-majority-in-parliament-for-legislation-to-curb-use-of-pesticides>.

11 Council of the EU, "Agriculture and Fisheries Council, 26 February 2024", <https://www.consilium.europa.eu/en/meetings/agrifish/2024/02/26/>.

12 European Commission, "Commission presents recommendation for 2040 emissions reduction target to set the path to climate neutrality in 2050", 6 February 2024, <https://ec.europa.eu/commission/presscorner/detail/en/ip_24_588>.

13 European Commission, "Securing our future Europe's 2040 climate target and path to climate neutrality by 2050 building a sustainable, just and prosperous society", COM/2024/63 final.

14 Jennifer McGuinn et al., *Rural areas and the geography of discontent*, 2024, European Committee of the Region.

expand their influence in the European Parliament election, but it is highly likely that far-right activities to obtain the support of farmers will intensify.

According to the Special Eurobarometer (Climate Change), one of the surveys on specific themes that are part of the Eurobarometer series of surveys run by the European Commission, climate change shifted from first place in the previous survey (March - April 2021), in terms of the ranking of severe problems faced by the world[15], to third place in the most recent survey (May - June 2023), being replaced in first place by poverty, famine, and water shortage, with armed conflict in second place. This change can be analyzed to represent the impact of the invasion of Ukraine and the conflict in Gaza. At the same time, however, 77% of respondents continued to answer that "Climate change is an extremely serious problem," a figure which has not changed significantly from the past two surveys (in 2019 and 2021).
Furthermore, comparing the results for the Standard Eurobarometer survey from the past five years[16], the ratio of respondents who consider "Rising prices, inflation, and the cost of living" to be the most serious problem faced in each country has been rising since 2021 (with an increase from 16% in winter 2020 to 41% in winter 2021 and 44% in winter 2023.) It is likely that the rising cost of living beginning in late 2021 has had a strong influence on these answers.

While the interest of EU citizens in climate change remains high, the increasing interest in rising prices in recent years has been clearly emerging, and it is becoming difficult to ignore its influence, particularly before elections.

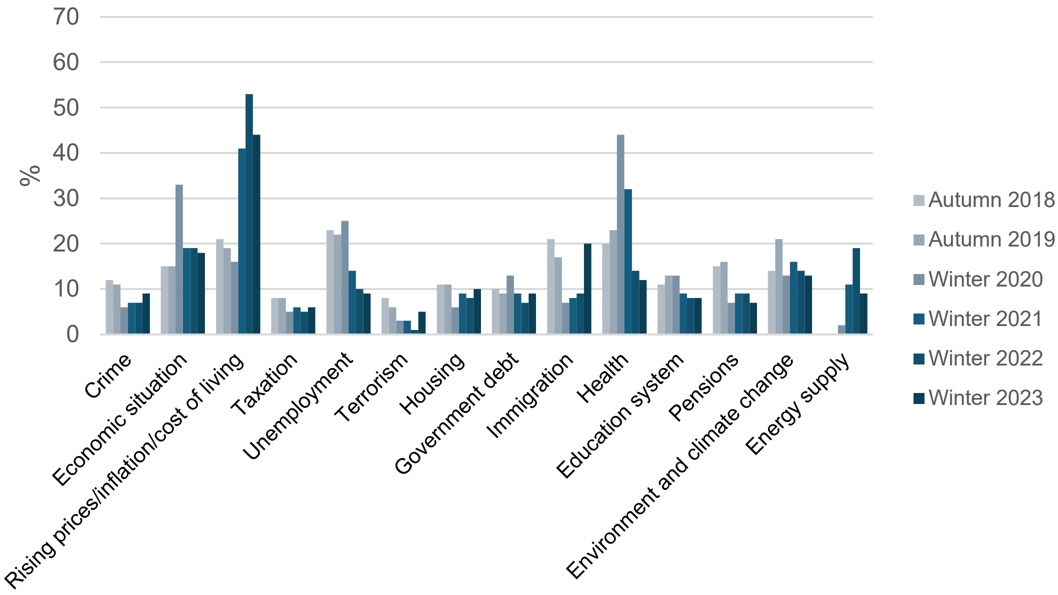

Fig.: Changes in Standard Eurobarometer Responses

Note: Answer to the question, "What do you think are the two most important issues facing (OUR COUNTRY) at the moment?" (MAX. 2 ANSWERS)

Source: Standard Eurobarometer 90, 92, 94, 96, 98, 100

Countries in Europe are rethinking their policy in light of the expanding dissatisfaction and concern with the rising economic burden, but at the same time, there has been additional criticism to the effect that policy changes lower the predictability of policy for companies. In the EU, the 2040 reduction targets will be proposed as legislation by the next European Commission after the coming European Parliament elections. While the center-right European People's Party (EPP) and center-left Progressive Alliance of Socialists and Democrats (S&D) are expected to take first

[15] The question was, "Which of the following do you consider to be the single most serious problem facing the world as whole?", with possible answer choices of, "Climate change / International terrorism / Poverty, hunger and lack of drinking water / Spread of infectious diseases / The economic situation / Health problems due to pollution / Proliferation of nuclear weapons / Armed conflicts / The increasing global population / Deterioration of nature / Deterioration of democracy and rule of law / Other / None / Don't know"

[16] The Standard Eurobarometer survey is held twice annually (in summer and winter). It is designed with a focus on monitoring trends regarding the EU as a whole, the European Commission's priorities, and contemporary social and political events. This paper utilized the results from the winter Standard Eurobarometer.

and second place in the coming European Parliament elections, it remains unclear whether the far-right will reach third place or otherwise achieve a position of influence over EU policy issues. Accordingly, an even more difficult balancing act will be required in Europe between the ambitious targets on the one hand versus the agricultural and industrial sector on the other for achieving the goal of climate neutrality by 2050.

Substantial decline in Commercial Industry sector energy consumption and background statistical accuracy issue

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Summary

Final energy consumption in FY2022 decreased by 3.3% from the previous year, the first decline in two years. The Transportation sector was the only energy consumption gainer, posting a 4.0% increase thanks to the easing of behavioural restrictions. The industry sector (Manufacturing and Agriculture, Fishery, Mining and Construction) reduced energy consumption by a steep 6.4% due to sluggish manufacturing production. The Residential sector registered a 2.3% decrease due to fewer opportunities to stay at home and a drop in space/water heating demand under warm winter weather, cutting energy consumption for the second straight year. The Commercial Industry sector recorded a 5.3% decline, the second fastest fall after the industry sector decrease.

Why did the Commercial Industry sector reduce energy consumption so remarkably despite the normalisation of the services industry after the COVID-19 disaster? The reason may be found in the statistical system and accuracy rather than in energy efficiency improvement or warm winter weather. A major factor behind the sharp Commercial Industry sector energy consumption decline was a drop in gasoline and other energy consumption that was caused by Unable to Classify subsector contained in the Commercial Industry sector. The Commercial Industry sector reportedly covers energy consumption by public sector vehicles. Given a mismatch between energy supply and demand, however, we can suspect that an energy consumption decline in the *pure* commercial sector may have been more moderate.

For most of the last 10 years, diesel oil in Unable to Classify was more than any other energy source, accounting for 10% of diesel oil supply. Due to the wide range of applications of diesel oil, it is not easy to determine the cause of this situation. Therefore, we evaluated the correlation between diesel oil demand in each user category and supply excluding the influence on each category from demand in other categories. As a result, we found that some improvements could be made in Agriculture, Fishery, Mining and Construction, the specified industries of the Commercial Industry sector, and Truck and Lorry, known for the largest diesel oil demand.

Figure 1 | Commercial Industry sector energy consumption (year-on-year changes)

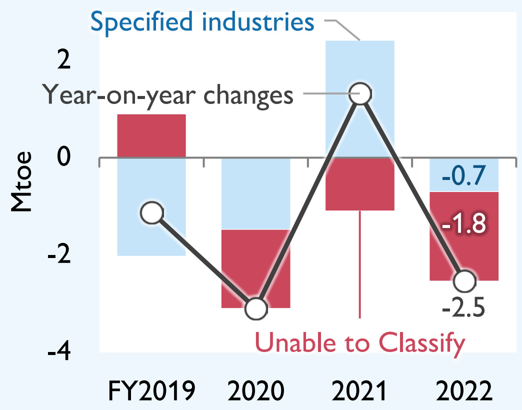
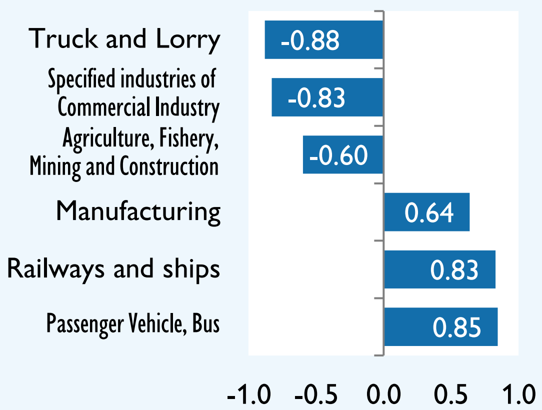


Figure 1 | Partial correlation coefficient between diesel oil demand in each user category and supply



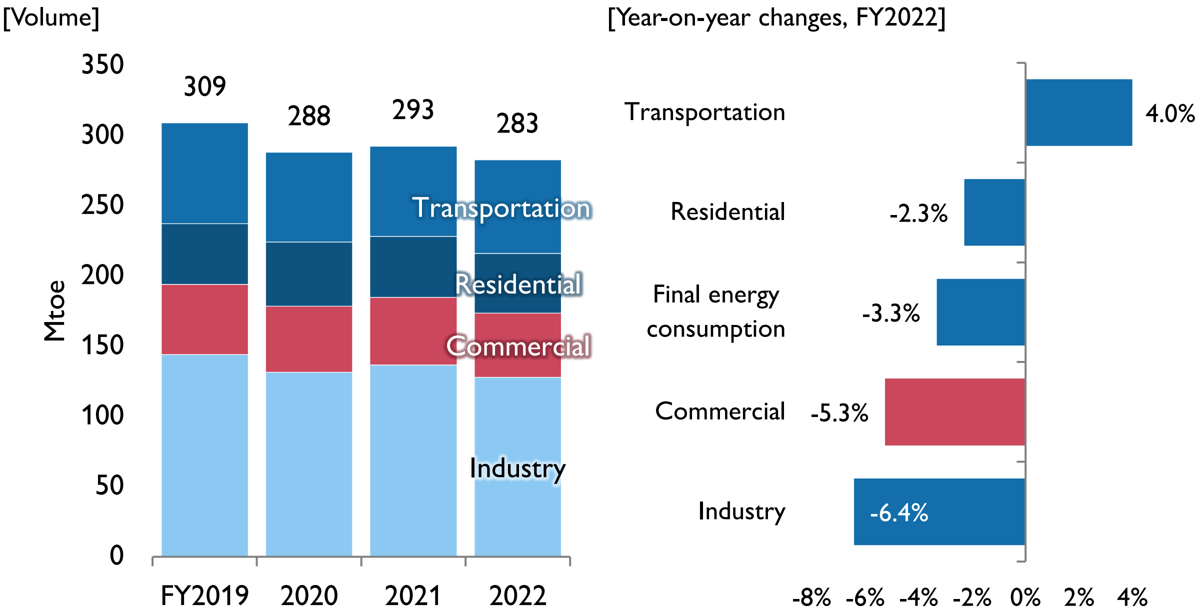
Keywords: diesel oil, Commercial Industry sector, Unable to Classify, trucks, fuel efficiency, General Energy Statistics

In FY2022, the diesel oil supply-demand gap widened as a fuel efficiency improvement for trucks more than offset an increase in truck mileage in a manner to reduce the demand. It, however, is unclear whether this rapid improvement in fuel efficiency accurately reflects reality. It is implied that the accuracy of the Energy Consumption Statistics and, above all, of the Survey on Motor Vehicle Fuel Consumption should be improved to resolve the "missing barrels" of diesel oil. Specific improvement measures may include the creation of various verification opportunities and the improvement of a commercial vehicle survey that is limited to seven days a month.

Energy consumption declined for the first time in two years, slipping below the level seen in the first year of the COVID-19 pandemic

According to the General Energy Statistics[1] released recently by the Agency for Natural Resources and Energy, Japan's final energy consumption in FY2022 decreased by 3.3% from the previous year for the first decline in two years (Figure 3). As economic and social activities were on the way out of the COVID-19 disaster, real gross domestic product (GDP) increased by 1.5% in the year. This GDP growth, however, was driven by the services industry (with the Tertiary Industry Activity Index rising by 2.2%), which benefited from the easing of behavioural restrictions to prevent COVID-19 infections, and by the machinery industry (with the Industrial Production Index increasing by 2.0%), including automakers, which expanded production after a decline attributable to semiconductor and other component shortages. Both are non-energy-intensive industries. On the other hand, production was sluggish in manufacturing industries other than the machinery industry, leading the overall mining and manufacturing production index to drop by 0.3% for the first decline in two years. Temperatures, which have a significant impact on energy demand, tended to be higher than in the previous year. Higher temperatures contributed to an increase in demand for space cooling in summer and a decrease in demand for space/water heating in winter. Russia's invasion into Ukraine accelerated energy price hikes, exerting downside pressure on energy demand.

Figure 2 | Final energy consumption



Source: Agency for Natural Resources and Energy "General Energy Statistics",
https://www.enecho.meti.go.jp/statistics/total_energy/

Transportation (sector code in the General Energy Statistics: #800000) was the only sector to increase energy consumption, posting a 4.0% rise. This was because consumption by Passenger Transportation (#810000) soared as car use recovered from low levels in FY2020 and FY2021 due to the easing of behavioural restrictions. On the other hand, manufacturing production was sluggish, including production in energy-intensive petrochemical and steelmaking industries. As a result, the industry sector[2] recorded a 6.4% decline in energy consumption, the third ever sharpest fall after plunges in FY2020 or the first year of the COVID-19 disaster and FY2008 amid the global financial crisis. This

[1] https://www.enecho.meti.go.jp/statistics/total_energy/ (Accessed on 12 April 2024)

[2] Manufacturing (#620000) and Agriculture, Fishery, Mining and Construction (#610000). Energy consumption in the industry sector is dominated by Manufacturing.

was the fastest decline among sectors in FY2022. In the Residential sector (#700000), fewer opportunities to stay at home amid the easing of behavioural restrictions affected energy consumption. A decline in space/water heating demand under warm winter weather more than offset an increase in space cooling demand under summer heat waves. Although the Residential sector in FY2020 and FY2021 had been the only sector to increase energy consumption from the pre-COVID-19 level, its consumption in FY2022 decreased by 2.3% from the previous year, slipping below the FY2019 level. The Commercial Industry sector (#650000) posted a 5.3% energy consumption decline in FY2022, the second fastest after the industry sector decrease.

Why was the Commercial Industry sector decline so remarkable?

Here is a question. Why was the decline in the Commercial Industry sector so remarkable? Services, including personal services, were being normalised after the devastation caused by the COVID-19 disaster. For example, the Nationwide Travel Support that started in October 2022 stimulated tourism demand, leading the accommodation industry to regain its vitality to the extent where labour shortages were seen. For the answer to the question, some people may look to temperatures. Certainly, it is suspected that warm winter weather worked to reduce energy consumption through a decrease in space/water heating demand. The Commercial Industry sector, however, features less space/water heating demand and more space cooling demand, which increased in FY2022, than the residential sector. Nevertheless, the energy consumption decline in the Commercial Industry sector was more than two times faster than in the Residential sector. Temperature data rather deepen the question.

Perhaps the answer to the question should be sought in the statistical system. There are three types of tables in the General Energy Statistics, with different sectors and energy intensities. Two tables other than the summary table provide a breakdown of the Commercial Industry sector (Table 1). The breakdown covers not only specified industries[3] ranging from Electricity, Gas, Heat Supply and Water (#651000) to Government (#680000) but also Unable to Classify (#690000) that should be revisited here. The Commentary of General Energy Statistics by the Agency for Natural Resources and Energy[4] explains:

> *Energy consumption of aircraft, ships and vehicles used by the public sector for policing, firefighting, maritime security, defence and other purposes is covered in this sector as they do not transport passengers or cargo.*

The Unable to Classify made a great contribution to the decrease in the Commercial Industry sector in FY2022. It, while accounting for less than 10% of the Commercial Industry sector's energy consumption, posted a greater energy consumption decrease than the specified industries (Figure 4). Of the sector's energy consumption decline at 2.5 million tonnes of oil equivalent (Mtoe) or 5.3%, it captured 1.8 Mtoe with -3.8% of contribution.

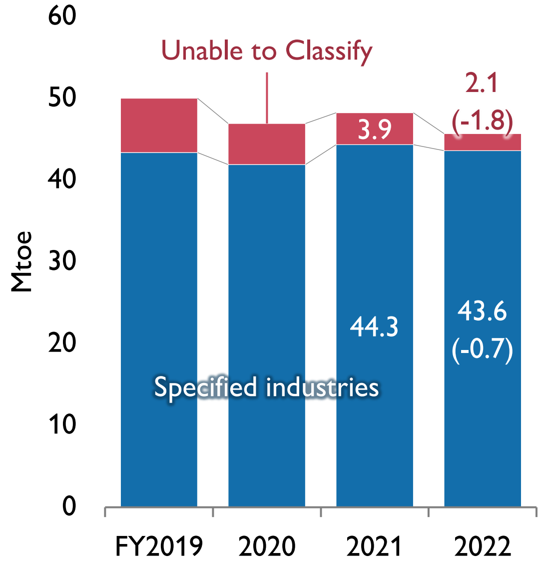
[3] "Specified industries" represent a term used for this paper, failing to appear in the General Energy Statistics.

[4] https://www.enecho.meti.go.jp/appli/public_offer/2023/data/0216_02_04.pdf (Accessed on 16 February 2024)

Table 1 | Breakdown of Commercial Industry sector

Commercial Industry (#650000)
Specified industries
◆ Electricity, Gas, Heat Supply and Water (#651000)
◆ Information and Communications (#652000)
◆ Transport and Postal Activities (#653000)
◆ Wholesale and Retail Trade (#654000)
◆ Finance and Insurance (#655000)
◆ Real Estate and Goods Rental and Leasing (#656000)
◆ Scientific Research, Professional and Technical Services (#657000)
◆ Accommodations, Eating and Drinking Services (#658000)
◆ Living-related and Personal Services and Amusement Services (#659000)
◆ Education, Learning Support (#660000)
◆ Medical, Health Care and Welfare (#661000)
◆ Compound Services (#662000)
◆ Miscellaneous Services (#663000)
◆ Government (#680000)
Unable to Classify (#690000)

Figure 4 | Commercial Industry sector

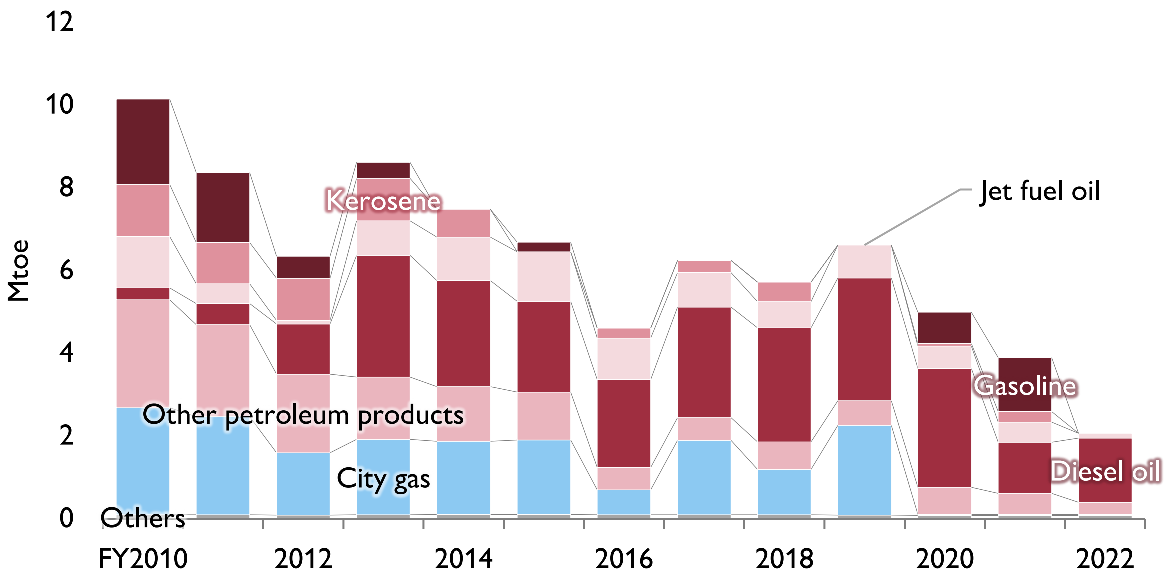


Note: In parentheses are changes from the previous year
Source: Agency for Natural Resources and Energy "General Energy Statistics", https://www.enecho.meti.go.jp/statistics/total_energy/

What are energy sources that contributed to the energy consumption decrease covered by Unable to Classify?

If so, what are energy sources that contributed to the energy consumption decrease of 1.8 Mtoe covered by Unable to Classify in FY2022? First, gasoline accounted for 1.3 Mtoe of the decline, followed by jet fuel oil for 0.4 Mtoe (Figure 5).

Figure 5 | Unable to Classify



Source: Agency for Natural Resources and Energy "General Energy Statistics", https://www.enecho.meti.go.jp/statistics/total_energy/

It, however, is difficult to believe that the disappearance of gasoline consumption for policing and firefighting services and a 75% plunge in jet fuel oil consumption by the Japan Coast Guard and the Self-Defense Forces from FY2021 to FY2022 reflect reality. Rather, it may be more natural to interpret it as statistical errors as defined by the Commentary of General Energy Statistics by the Agency for Natural Resources and Energy as follows:

> *Energy consumption that is logically estimated consumed domestically but cannot be classified into any final consumption sector is treated as Unable to Classify (#690000).*

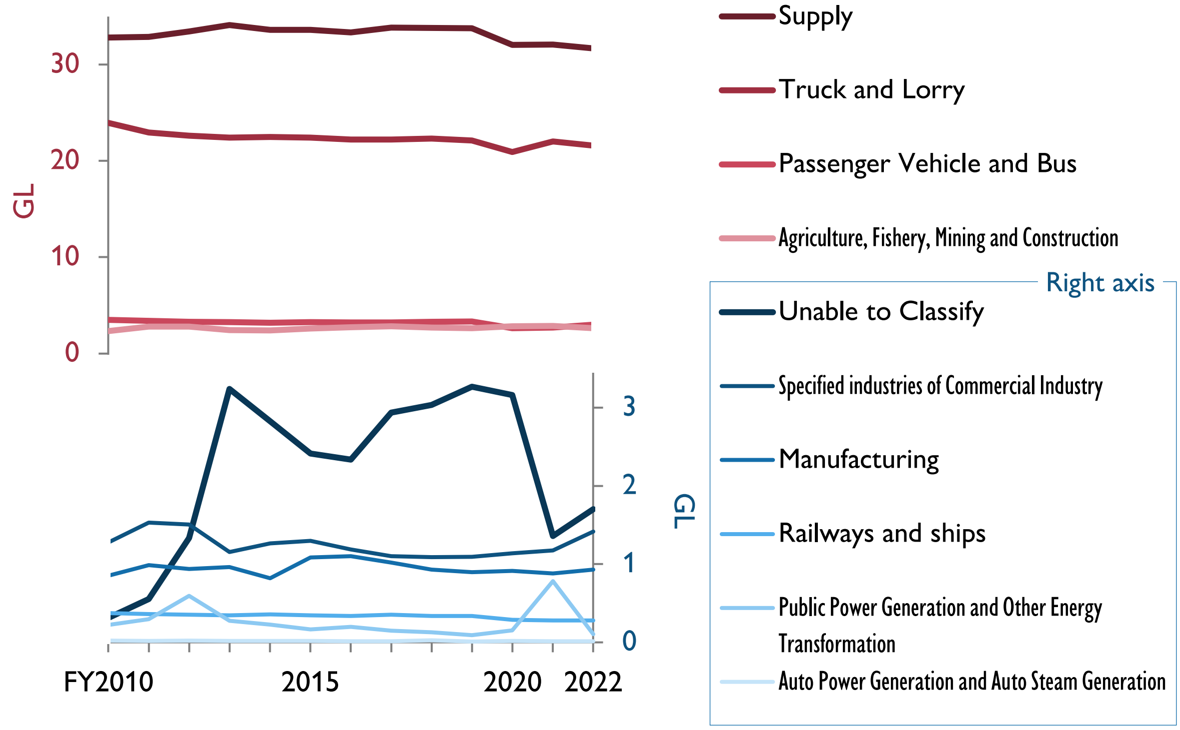
It thus represents a gap between supply and demand excluding Unable to Classify. According to the interpretation, an energy consumption decline in the *pure* commercial sector in FY2022 can be presumed as more moderate. A decline that is similar to or more moderate than the Residential sector fall may be persuasive.

However, it is ideal for numbers in statistics to be picked up with no consideration given to the need for such speculation. In this sense, amount of Unable to Classify (or its year-on-year changes) must be reduced close to zero. As gasoline is mostly consumed by vehicles, the Survey on Motor Vehicle Fuel Consumption by the Ministry of Land, Infrastructure, Transport and Tourism, which covers demand, must be made consistent with the Mineral Resources and Petroleum Products Statistics by the Agency for Natural Resources and Energy, which cover the supply side. If the consistency between them is further enhanced, the impact of Unable to Classify that may disrupt the Commercial Industry may be mitigated. The Mineral Resources and Petroleum Products Statistics known as a complete enumeration look accurate. In 2023, however, domestic sales of liquefied petroleum gas were revised by nearly 10% due to erroneous reports by some business establishments. As well as the Survey on Motor Vehicle Fuel Consumption, which is a sample survey, the supply side statistics should be improved further.

How about diesel oil which dominates Unable to Classify?

Gasoline and jet fuel oil statistics are easy to find measures to improve because their consumption areas are limited. In contrast, diesel oil, for which Unable to Classify increased by 344 ML in FY2022, has a wide range of uses, indicating that multiple primary surveys are required to depict the entire picture of its supply and demand. This is no exception regarding the tabulation of diesel oil data in the General Energy Statistics. Because of this, diesel oil posted more Unable to Classify than any other energy source in most of the latest decade. The errors for diesel oil, though declining in the latest two years, accounted for 10% of diesel oil supply in the 10 years (Figure 6). It is desirable to determine which primary surveys are responsible for this situation. It, however, cannot be easily elucidated since Unable to Classify are like statistical errors.

Figure 6 | Supply and demand of diesel oil



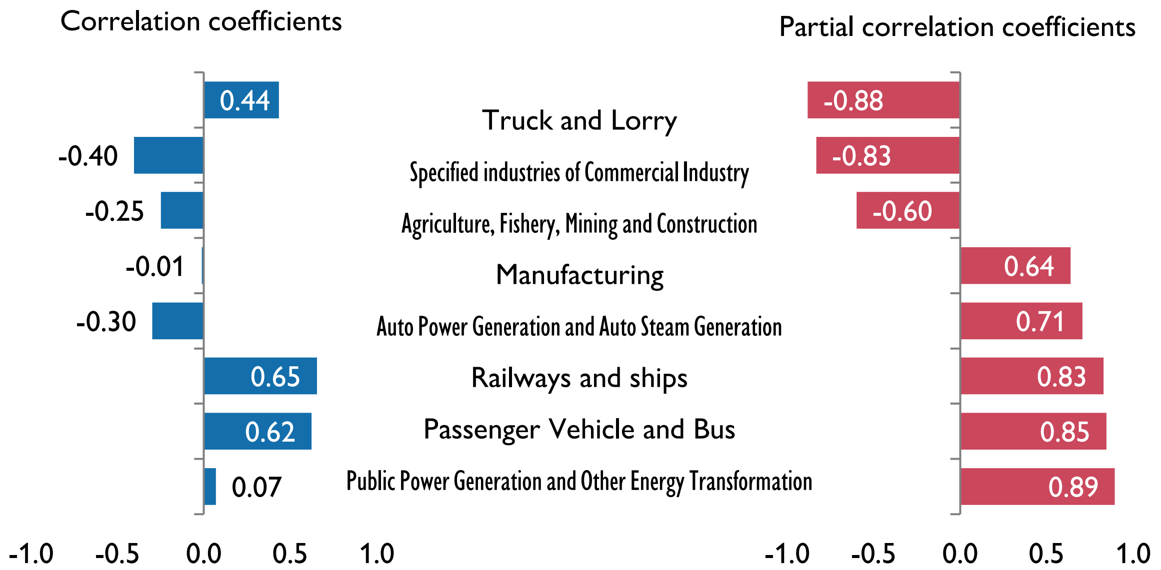
Source: Agency for Natural Resources and Energy "General Energy Statistics", https://www.enecho.meti.go.jp/statistics/total_energy/

Therefore, we tried to change our thinking and seek clues in General Energy Statistics data. We compared year-on-year changes in diesel oil demand for each user category and supply. Specifically, we checked how demand changes in each category are linearly correlated with supply changes. Correlation coefficients obtained in this way were 0.6 or more for railways (#813000 and #852000) and ships (#814000 and #853000), and for Passenger Vehicle (#811000) and Bus (#811500), indicating that the demand-supply correlation is fairly good for these categories (see the left part of Figure 7). A correlation coefficient for Truck and Lorry (#851000), the largest consumer of diesel oil, and in the same Transportation sector with the abovementioned modes, was 0.44, showing a smaller supply-demand correlation than for the other categories in the Transportation sector. For other user categories, however, supply-demand correlations were poor. In particular, supply-demand correlations were negative for the specified industries of the Commercial Industry, Auto Power Generation (#260000) and Auto Steam Generation (#250000), and Agriculture, Fishery, Mining and Construction (#610000) for which the Energy Consumption Statistics by the Agency for Natural Resources and Energy are used for calculation for the General Energy Statistics, meaning that supply declines when demand in these categories increases. We had no choice but to have doubts about such correlations.

Is the key to diesel oil in the Survey on Motor Vehicle Fuel Consumption and the Energy Consumption Statistics?

However, diesel oil supply and demand in each user category are not independent. For example, suppose that there were many years when diesel oil demand increased in the largest user category of Truck and Lorry while decreasing incidentally in Agriculture, Fishery, Mining and Construction. In this case, demand in Agriculture, Fishery, Mining and Construction is negatively correlated with supply, with supply looking inconsistent with demand. Taking such situation into account, we calculated a partial correlation coefficient to measure how demand in each user category is correlated with supply, after eliminating the influence of demand in other categories. As was the case with correlation coefficients, partial correlation coefficients were relatively high for railways and ships, and for Passenger Vehicle and Bus (seen the right part of Figure 7).

Figure 7 | Correlation coefficients and partial correlation coefficients between diesel oil demand in each user category and supply



Notes: Supply covers Domestic Primary Energy Supply (#190000), Oil Product Blending (#221000), Oil Refinery (#222000) and Other Energy Transformation (#280000) in the General Energy Statistics. The correlation coefficient and partial correlation coefficient are for between annual changes in demand in each user category and those of supply for the FY2011-2022 period.
Source: Calculated from the Agency for Natural Resources and Energy "General Energy Statistics", https://www.enecho.meti.go.jp/statistics/total_energy/

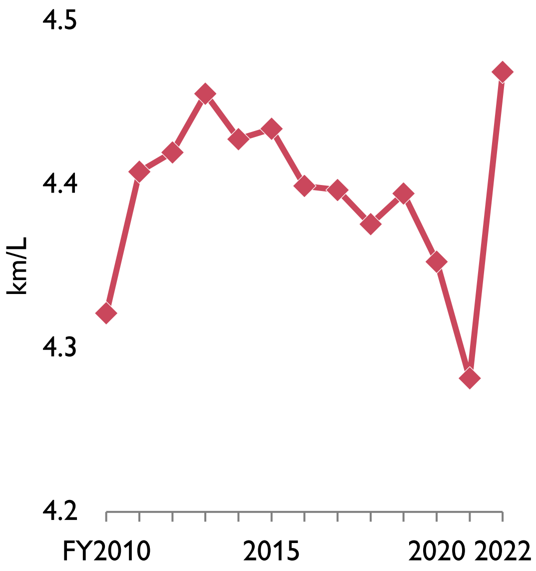
On the other hand, the user categories of Manufacturing (#620000), Auto Power Generation and Auto Steam Generation showed good partial correlation coefficients whilst posting negative correlation coefficients. When the General Energy Statistics are tabulated, not only the Energy Consumption Statistics but also the relatively accurate Current Survey of Energy Consumption by the Ministry of Economy, Trade and Industry are used for these user categories. This might have produced the better results. This is because the relationship between demand and supply as indicated by partial correlation coefficients is doubtful for the specified industries of Commercial Industry and Agriculture, Fishery, Mining and Construction for which the Current Survey of Energy Consumption are not used.

It should be noted here that the user category of Truck and Lorry recorded the largest negative partial correlation coefficient, implying that the reasonably good relationship between diesel oil demand for Truck and Lorry and supply as indicated by the correlation coefficient is only superficial and that whether diesel oil supply is consistent with demand for Truck and Lorry is uncertain. The diesel oil demand situation for Truck and Lorry, which account for 70% of diesel oil supply, is extremely significant for improving the supply-demand discrepancy.

Truck fuel efficiency in FY2022 behind expanded Unable to Classify for diesel oil

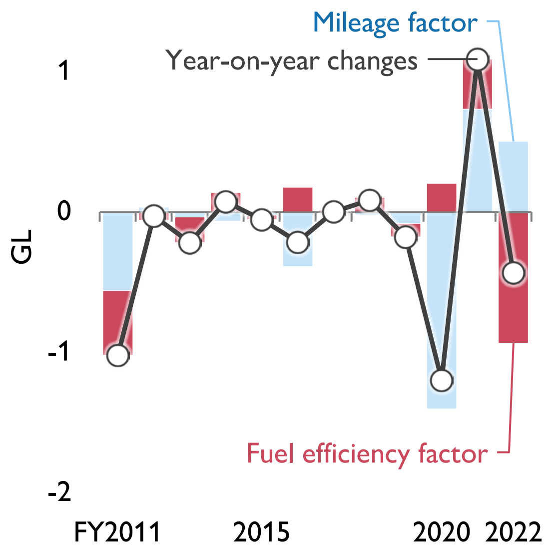
In FY2022, the rapid improvement in truck fuel efficiency more than offset the impact of an increase in truck mileage, exerting great downside pressure on diesel oil demand (Figures 8 and 9). Furthermore, supply failed to decline to reflect demand's reactionary fall after an increase in FY2021 for Public Power Generation (#240000) and Other Energy Transformation (#301000 and #350000). As a result, the supply-demand gap widened.

Figure 8 | Fuel efficiency for diesel-powered trucks



Source: Calculated from Ministry of Land, Infrastructure, Transport and Tourism "Survey on Motor Vehicle Fuel Consumption"

Figure 9 | Diesel oil demand for trucks (year-on-year changes)



Source: Calculated from Ministry of Land, Infrastructure, Transport and Tourism "Survey on Motor Vehicle Fuel Consumption"

Truck fuel efficiency had been relatively stable since FY2011, following the launch of the Survey on Motor Vehicle Fuel Consumption. However, a change in the efficiency in FY2022 was the largest ever, nearly seven times the previous 10-year average[5]. Whether or not this rapid improvement in fuel efficiency accurately reflects the actual situation cannot be verified due to the lack of detailed data or other statistics that can be compared. Anyway, the rapid improvement in truck fuel efficiency was one of the factors that statistically pushed up demand for diesel oil for the Commercial Industry through the expansion of a gap between supply and demand.

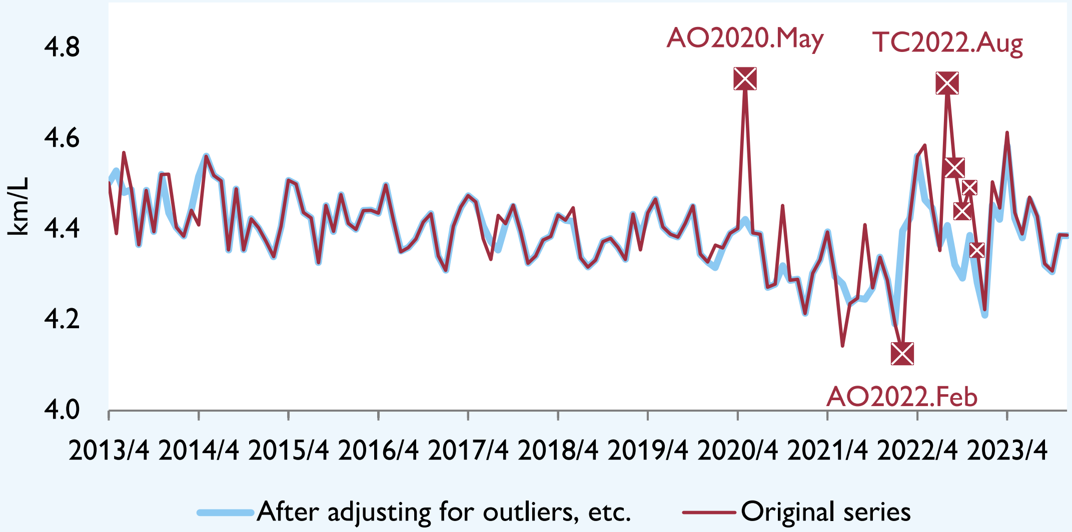
Box 1 | Destabilisation of fuel efficiency of diesel-powered trucks

Since FY2011, diesel-powered trucks' fuel efficiency calculated from the Survey on Motor Vehicle Fuel Consumption had remained in a range around 4.4 km/L. Since around FY2022, however, the changes seem to have become somewhat larger. Therefore, we used monthly data to delve into the trend. Specifically, we used the X-13ARIMA-SEATS seasonal adjustment method of the U.S. Census Bureau to verify the presence or absence of values that deviate from the trend. For the period from April 2013 to December 2023, for which monthly data were published, additive outliers in May 2020 and February 2022 (AO2020.May and AO2022.Feb) and a temporary change from August 2022 (TC2022. Aug) were detected (Figure 10).

May 2020 is considered to be an extremely special period, as a state of emergency was first declared due to the COVID-19 infection. In the period for upward deviation from August 2022, there was neither state of emergency declaration nor quasi-state of emergency declaration to prevent the COVID-19 spread, making it difficult to attribute the temporary change to any COVID-19 countermeasures.

[5] Some may believe that diesel oil price hikes led to the improvement in fuel efficiency. However, the year-on-year increase in diesel oil prices in FY2022 was limited to ¥7.6/L, the sixth largest increase in the 12 years from FY2011, due to the effects of the fuel oil price change mitigation subsidy that came into effect in January 2022 (Agency for Natural Resources and Energy "Petroleum Product Price Survey", gas station retail price). In FY2021, in contrast, fuel efficiency posted the greatest deterioration in the past 12 years despite the rapid price hike of ¥26.6/L.

Figure 10 | Fuel efficiency for diesel-powered trucks



Source: Ministry of Land, Infrastructure, Transport and Tourism "Survey on Motor Vehicle Fuel Consumption" [original series]

If the impact of this temporary change from August 2022 is eliminated, fuel efficiency in FY2022 may decrease by 1.9% from the actual value of 4.47 km/L to 4.38 km/L, indicating its deterioration. If the mileage is in line with the statistics, demand for diesel oil for trucks may be 422 ML more, reaching the level for the previous year. As a result, the year-on-year increase of 344 ML in Unable to Classify for diesel oil may be completely cancelled out.

Situation regarding statistics development is difficult despite its growing need

It is essential to improve the accuracy of the Energy Consumption Statistics and, above all, of the Survey on Motor Vehicle Fuel Consumption, given the scale of the demand, to resolve the "missing barrels" of diesel oil. Specific improvement measures may include the publication of more detailed statistical data for encouraging various quarters' verification and the reform of the survey method for commercial vehicles, which now limits the survey to seven days a month.

There is a growing need for more accurate, detailed, and fast statistics and data. However, there is a serious shortage of human resources for statistical development. Although there are many challenges and various constraints, we hope that the current situation will be improved from the perspective of appropriate policy implementation. OKUMA Shigenobu[6] stated:

> *"If the current state of the country fails to be clarified in more detail, the government will lose the reason for implementing policies. If the government fails to refer to the results of past policies, it will be unable to know whether the past policies were good or not."*

[6] 1838-1922. A Japanese statesperson, the eighth and the 17th prime minister, the founder and the first president of the Statistics Bureau.

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