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Decarbonizing Asian Economies with Green Hydrogen

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The Institute of Energy Economics, Japan

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The Gas Market Liberalization Progress under High Energy Price Environment◆

Yuichi Yanouchi*

1. Introduction

Six years have passed since Japan's city-gas retail market for all the market segments was opened for competition on 1 April 2017. This paper looks at the latest developments in the city gas market under the recent high commodity price environment, following the paper "Four Years of Competition after the Liberalisation of the City-gas Retail Market" by Mr. Daisuke Masago of the Institute of Energy Economics, Japan - IEEJ, presented at the 37th Conference on Energy System, Economy, and Environment in 2021.

2. High Energy Prices and Their Impacts on the Japanese Domestic City-gas Market

As energy demand rebounded with revitalized economic activities after relaxation of restrictions related to the Covid-19 Pandemic in 2021 and energy supply capacity did not catch up with the increasing demand due to sluggish performance of aggression in Ukraine in 2022, energy prices went up to the highest levels in the history in the year. Natural gas and LNG prices also surged to historical highs around the world from the Northern Hemisphere summer in 2021. The upward trend of LNG prices also continued at a slower rate in Japan, where long-term contracts with linkage to crude oil prices represent 70% - 80% of the total supply, with the average price reaching to the highest ever of JPY 164,922 per tonne in September 2022. However, as Japan does not have an integrated nationwide pipeline network, the retail gas business does not have as many new entrants as the electric-power retail business, nor an established wholesale gas market comparative to the Japan Electric Power Exchange (JEPX) in the electric power business. As new entrants in the retail gas markets depend on contractual arrangements for gas transportation and procurement with pipeline operators and wholesale companies, they do not directly suffer from surges in wholesale gas market prices. As gas source procurement costs for retailers can be passed onto retail sale prices, albeit some restrictions, retail companies do not make significant losses in retail sales even during the current high-LNG price period. The impact of the current high LNG prices on those retail sellers of gas has been relatively mitigated so far.

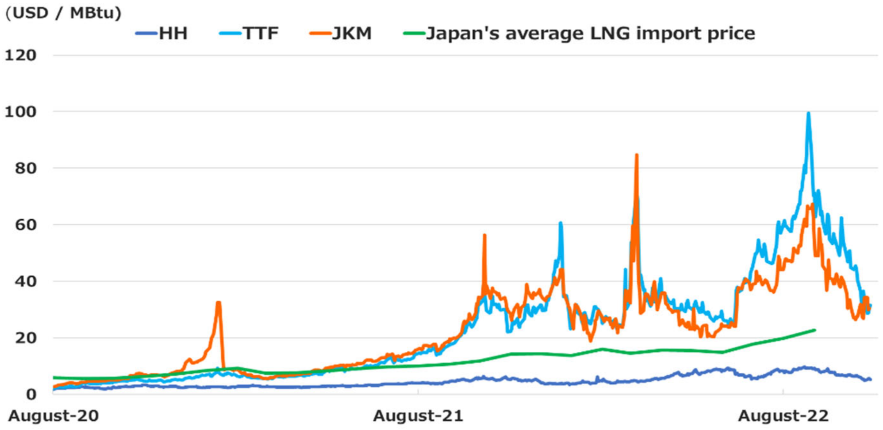

Fig. 1 World natural gas and LNG price trends

◆This article is a presenting paper at the 39th Conference on Energy, Economy, and Environment that Japan Society of Energy and Resources (JSER) hosted.

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3. Historical Developments and Objectives of Full Retail Liberalisation of the Gas Market

The retail gas market liberalisation in Japan started in 1995 when sales to customers of annual usage of more than 2 million m^3, such as large manufacturers and large-scale medical facilities. The threshold of liberalised sales had been lowered in phases thereafter. At last, all retail sales, including those to small customers, were opened up for competition in April 2017. The pipeline operating divisions of the largest city-gas companies (Tokyo Gas, Osaka Gas, and Toho Gas) were legally unbundled from their gas sales activities in April 2022, as part of the nation's gas system reform.

4. Progress of Gas Retail Competition

4-1. New Entrants into the Retail Segment

Before the full-retail liberalisation, the incumbent city-gas utility companies had been granted franchise business areas authorised by the nation's Minister of Economy, Trade and Industry. With the revision of the Gas Business Act enacted in April 2017, the retail gas business was transformed into one based on registrations to the Ministry of Economy, Trade and Industry (METI), and was fully opened up to competition. New entrants to the retail segment of the gas business have included LP-gas companies, electric power utility companies, new entrants into the electric-power retail business, and other various companies. As of 17 October 2022, the nation had 99 gas retail companies, while additional 44 companies had plans to start, or had already started, retail gas sales, increasing from 91 and 39, respectively, from 12 July 2021 when LNG prices started rising.

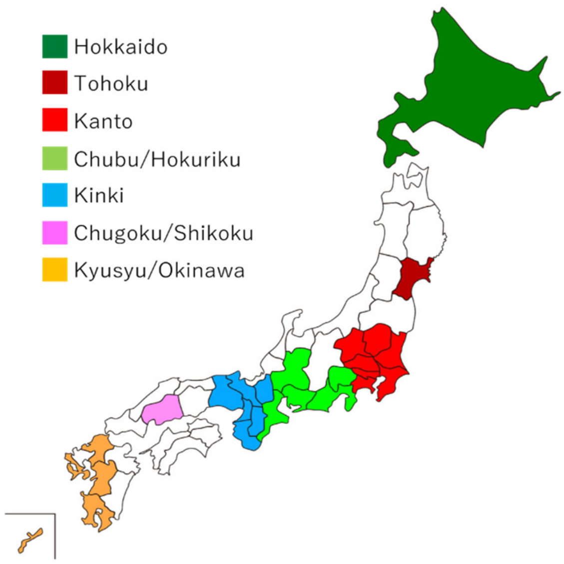

Fig. 2 Areas where new entrant retailers' registrations of retail gas sales

Fig. 2 indicates areas where the 44 prospective new entrants have made registrations of their planned retail gas sales. The incumbent gas utility companies have been categorised by size of business, capacity to procure gas sources, and supply facilities they have. 26 prefectures, where the first group of the largest incumbent companies (Tokyo Gas, Osaka Gas and Toho Gas) and the second group (Hokkaido Gas, Sendai-City Gas Office, Shizuoka Gas, Hiroshima Gas, Saibu Gas and Nihon Gas of Kagoshima) have business areas, have already had new entrants into retail gas sales. Declines in retail price levels and diversified retail service programmes have been observed in those areas where competitions are apparent with larger numbers of new entrants. On the other hand, the remaining 21 prefectures have hardly enjoyed positive impacts of the retail liberalisation in terms of retail price and service programmes unless the incumbent gas operators have tried to voluntarily improve them.

4-2. Trends in Retail Customer Switching

One of the most important indicators to review the developments and progress of the full retail gas liberalisation is the number of switchings, or customers who change their retail gas suppliers. The author has reviewed cumulative numbers and rates of customer switchings by region in the retail residential gas segments based on monthly data of the gas market published by the Electric and Gas Market Surveillance Commission.

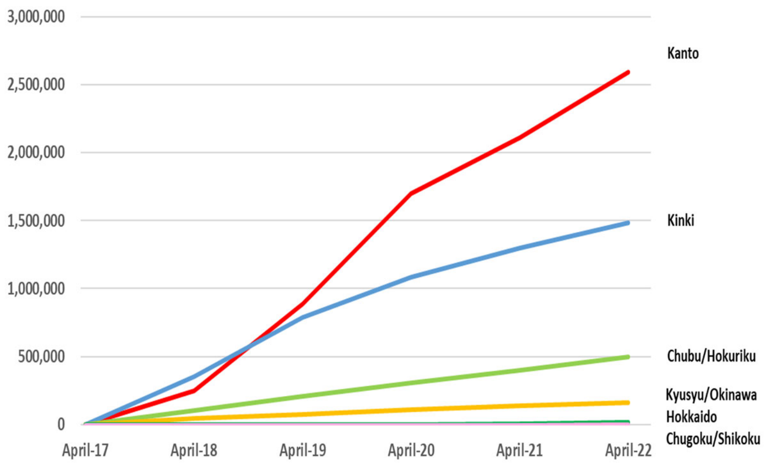

Fig. 3 Cumulative switchings by region for residential retail gas providers

Fig. 3 shows cumulative numbers of customer switchings in the retail residential gas segments in the six regions (Hokkaido, Kanto, Chubu/Hokuriku, Kinki, Chugoku/Shikoku, and Kyushu/Okinawa) where such customer switchings have been already reported. Although new entrants have been already registered in the franchise of the Sendai-City Gas Office in the Tohoku region, no such customer switchings have been reported yet. The nationwide total number of customer switchings in the residential gas sales segment was 4.89 million as of September 2022, increasing by 19% or 850 thousand from one year earlier, indicating a steadily increasing trend during the period of rising LNG prices from the summer of 2021. The largest numbers of switchings have been reported in the Kanto region since April 2019, after the Kinki region reported the largest numbers from the initial period of data collection until March 2019. The cumulative numbers of switchings were 2.68 million in Kanto representing 55% of the national total, 1.52 million or 31% in Kinki, 510 thousand or 10% in Chubu/Hokuriku, respectively. The three regions represented 4.71 million switchings, representing 96% of the total in the country.

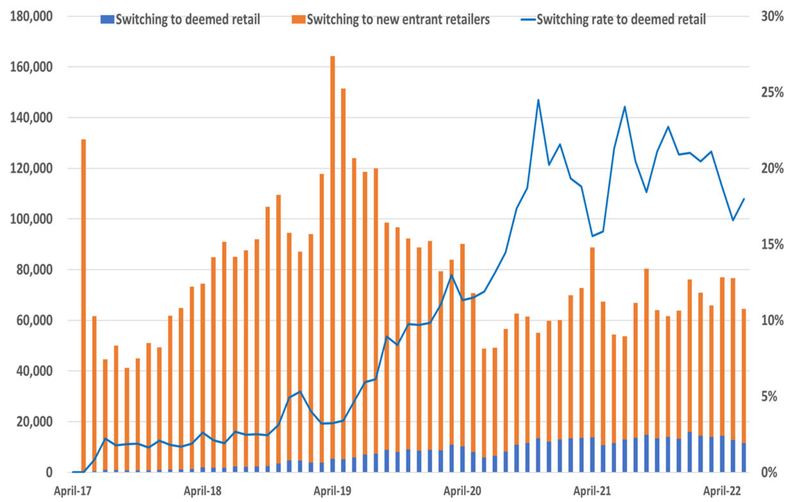

Fig. 4 Cumulative switching rates by region for residential retail gas providers

Fig. 4 indicates rates of customer switchings (shares of customers who have switched their retail suppliers in the total customers) by region in the retail residential gas segments. Kanto had the largest number of retail customers of 13.87 million as of September 2022, representing 52% of the national total, followed by 6.48 million in Kinki and 2.51 million in Chubu/Hokuriku. Although Kanto has recorded the highest numbers of monthly switchings in the residential gas retail segment since November 2018 mainly due to the largest total customer base compared to the other five regions, Kanto's cumulative switching rate lags behind Kinki's and Chubu/Hokuriku's. Although Kinki has the highest cumulative switching rate from the initial data reporting as of September 2022, the region has observed declines in the switching rate during the last three years, down to 2.77% during the last twelve months, the lowest since the start of the full retail liberalisation. While Chubu/Hokuriku and Kanto registered their highest switching rates in May 2017 and April 2019, respectively, the two regions have had still steady switching rates thereafter.

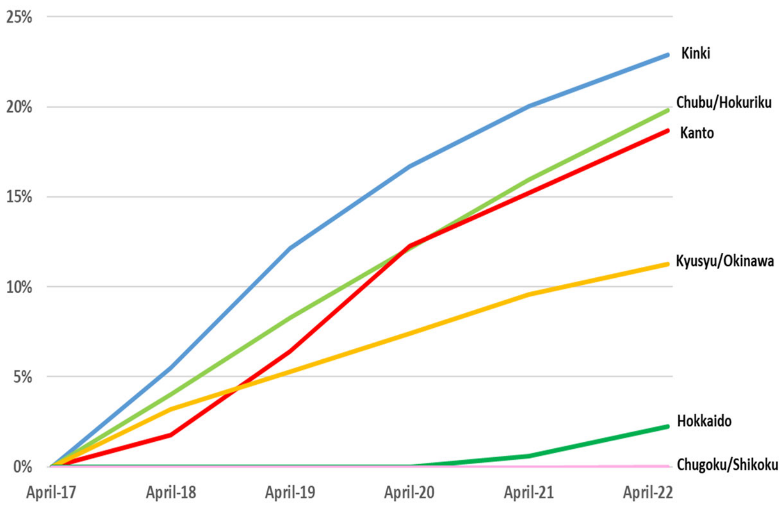

Fig. 5 Monthly number of switchings to new entrant retailers and deemed retailers (incumbent city gas utility companies) for residential retail gas sales

Fig. 5 indicates the national numbers of switchings to new entrants and those to the incumbent city-gas utility companies (so-called "deemed retailers") in the residential retail gas segment on monthly basis. From the beginning of the full retail liberalisation, monthly switchings to new entrants grew steadily to 189 thousand in April 2019. On the other hand, monthly switchings to the incumbent city-gas utility companies reached their highest, 16 thousand, in January 2022. Such switchings back to the incumbent city-gas utility companies have been in an increasing trend, representing one fifth of the total customer switchings during the last two years. While the trend will have to be further carefully analysed in the future, the increase in the switchings to the incumbent city-gas utility companies has been suspected to be caused by the increased customer bases of new entrants after they acquired 1.75 million retail customers in the first two years of the full retail liberalisation, as well as enhanced marketing efforts by the incumbents.

5. Startup Wholesale Programme

A new initiative to encourage new entry, the Startup Wholesale Programme was introduced in the fiscal year 2019 (from April 2019 to March 2020) in the regions where no or fewer switchings had been reported. Nine companies in the above-mentioned first and second groups have been required to offer such Startup Wholesale Programmes in their respective service areas. While there are 44 prospective new entrants into the gas retail business, 19 gas wholesale contracts had been concluded utilising the Startup Wholesale Programmes, including contracts covering multiple supply areas, by the end of March 2022. The number represents a significant increase in such contracts from five as of 1 October 2020. As the programmes have been introduced for three years since 2019, negotiations have been suspected to have advanced and new entrants have been suspected to have taken advantage of such programmes in multiple supply areas, contributing to the increase. Thanks to such programmes, new entrants in retail sales have emerged in Hokkaido, Hiroshima and Shizuoka for the first time. While customer switchings in the residential segment in Hokkaido have been suspected to be only utilising such Startup Wholesale Programmes, 17 thousand customers out of 700 thousand city-gas customers in total in Hokkaido have switched in two years.

6. Conclusion

The recent high prices of LNG have not apparently caused significant adverse impacts on retail gas suppliers in Japan. Hence, the number of retail gas companies, customer switching rates, and other developments of retail gas market liberalisation have suffered only limited impacts from the high LNG prices. An increase in customer switching back from new entrants to the incumbent city-gas companies has been confirmed as a new trend. Causal relationship between the high LNG prices and switching backs should be further investigated, including contractual conditions of both ends. As new entries utilising the Startup Wholesale Programmes increased from five to 19 in one and half years and all of the previous non-competitive regions of the above-mentioned second group, except for the area of Saibu Gas, have reported new entries, the Startup Wholesale Programmes have partially achieved their goals. However, progresses in some areas have been slow as the supply area of Hiroshima Gas only reported 10 customer switchings during the ten months after the first case utilising the Startup Wholesale Programme in September 2021. While no numerical targets have been set for the Startup Wholesale Programmes, efforts should be made to vitalize competition through expanding areas of new entries and increasing switchings.

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Factor of determining marginal abatement cost of CO_2 under carbon neutrality◆

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Abstract

Toward carbon neutrality, cost assessment for reducing CO_2 is essential. Although marginal abatement cost (MAC) is often used in the several previous studies, the factor determining MAC has not necessary been identified. Hence, it is important to clarify how MAC was determined in cost assessment. This study has developed Technology selection model to assess the optimized combination of energy technologies under constraints and identified technologies to determine MAC under 4 scenarios: (i) Base scenario, (ii) No nuclear scenario, (iii) Low CCS scenario, (iv) High fuel price scenario. As a result, this study showed MAC in 2050 was 478–743 USD/ t-CO_2. In the base scenario and no nuclear scenario, liquid synthetic fuel was additionally consumed instead of fossil fuel to reduce last 1,000 t-CO_2 toward carbon neutrality. Hence, liquid synthetic fuel was key factor to determine MAC. On the other hands, in the low CCS scenario hand high fuel price scenario, DAC was additionally installed. Thus, key technology or fuel to determine MAC was different. The approach to identify key factor determining MAC can be expected to contribute to policy making for expanding key technologies or reducing total cost toward carbon neutrality.

Key words: Energy model, Carbon neutrality, Marginal abatement cost, Energy policy, Cost analysis.

1. Background

Japan has declared its goal of achieving carbon neutrality by 2050, which is to reduce overall greenhouse gas emissions to zero. To achieve this ambitious goal, there is a growing need to radically transform Japan's energy demand and supply structure by introducing various energy technologies such as renewable energy and using highly cost-effective technologies. For this, it is important to clarify the costs associated with reducing greenhouse gases and the specific factors that affect cost, and to formulate measures toward the adoption of technologies that are important for achieving carbon neutrality.

To date, there have been numerous studies assessing the costs associated with reducing greenhouse gases[1-3]. In previous studies, the trend had been to use the marginal abatement costs (MAC) of CO_2, which is the cost required to reduce an additional 1 t of CO_2, as one of the evaluation indices for cost. On the other hand, while MAC is estimated through the shadow price of the CO_2 emission constraint formula in the optimization model, the determining mechanism is not simple, and the factors determining MAC are not necessarily clear.

In light of that, this study examines the evaluation methods for MAC using a technology selection model in order to evaluate the costs associated with reducing greenhouse gases and its determining factors more clearly. In this study, two methods are considered as methods for estimating MAC: evaluation through the shadow price of CO_2 emissions, and a differential calculation method that performs optimization calculations twice before and after making infinitesimal changes to the CO_2 emission constraint. The MAC in each case and the factors determining MAC are then identified.

2. Method

2-1. Technology Selection Model

In this study, the technology selection model developed by Otsuki et al[4] and Kawakami et al[5], which targets Japan's overall energy system, was used as the basis for conducting the evaluation. This model uses the capital cost of each energy technology as the input value, and based on the linear programming method, generates as output the amount of energy technology introduced that minimizes the cost of the overall energy system under various constraints related to emissions

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constraint, power demand and supply, and other factors. Approximately 300 technologies were identified for selection in the respective sectors of energy transition, industry, transport, household, and business, and the following flow was established: from primary energy supply to energy transition, secondary energy, inter-regional transportation, and final consumption (Fig. 1).

This model takes the sum of technology k, capital cost $ivc_{k,y}$ [USD /year]at point y [year], fuel cost $voc_{k,y}$ [USD/year], O&M cost $foc_{k,y}$ [USD /year], and energy procurement cost $flc_{k,y}$ [USD /year] as the total cost $ac_{k,y}$ [USD /year], and calculates the amount of each technology introduced $x_{k,y}$ so as to minimize the discounted cumulative cost through the objective function shown in Formula (1). All prices were treated as real prices of 2019. In this study, the final fiscal year y_e was taken to be 2080, and calculations were made for the interim years of 2019, 2030, 2040, 2050, and 2065. While the main target year of analysis was 2050, calculations were performed up to 2080 in consideration of the end effect.

$$min \sum_{k=1}^{n} \sum_{y}^{y_e} ac_{k,y} \cdot \left(\sum\nolimits_{y_2 \in YEAR_y} (1+DR)^{BY-y_2} \right) \quad (1)$$

$$ac_{k,y} = x_{k,y} \cdot \left(ivc_{k,y} + foc_{k,y} + voc_{k,y} + flc_{k,y} \right) \quad (2)$$

In the formula, $YEARy$ is the set of years represented by the point in time y (for example, 2030 is 2026–2035), and BY is the first year of analysis (=2019).

The representative constraints include CO_2 emission constraints, the balance of power demand and supply at each hour, the upper limit constraints on the amount of each type of power introduced depending on the location conditions, reserve capacity constraints, and load-following constraints, among others[4)].

This study describes the linear model using Mosel and obtains a solution by using the solver Xpress.

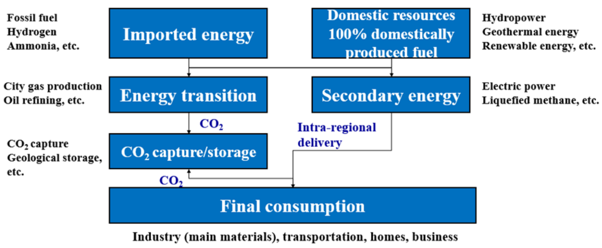

Fig. 1 Modeled energy system

2-2. MAC Evaluation

In this study, MAC was estimated using two methods. The first method, like methods frequently used in previous research, takes the shadow price of the CO_2 emission constraint formula obtained as the optimal solution of the dual problem, as MAC. The formulation of this is shown as Formula (3). In this method, while it is possible to obtain MAC through one optimization calculation, it is difficult to identify the specific factors that determine MAC.

$$MAC_y = \frac{\partial}{\partial CO_2} \sum_{k=1}^{n} ac_{k,y} \quad (3)$$

The second method performs the optimization calculation twice before and after infinitesimal changes are made to CO_2 emission constraints, and evaluates MAC based on the infinitesimal change $\Delta x_{k,y}$ of the amount of each technology introduced in the results of the two calculations, and the various costs given in the assumptions. This method is taken as the differential calculation method in this study, and its formulation is shown as Formula (4). While the differential calculation method takes twice the calculation time in comparison with the method of calculating the shadow price of CO_2 emission constraints, it is able to identify the specific technologies that determine MAC.

$$MAC_y = \sum_{k=1}^{n} \frac{\partial x_{k,y}}{\partial CO_2} \cdot \left(ivc_{k,y} + foc_{k,y} + voc_{k,y} + flc_{k,y}\right) \tag{4}$$

3. Assumptions

3-1. Case setting

Taking into account the following elements that are assumed to affect MAC—whether or not nuclear power is used, CO_2 storage capacity through CCS, and fuel prices, this study sets out the four scenarios shown in Table 1: (1) Base scenario, (2) No nuclear scenario, (3) Low CCS scenario, and (4) High fuel price scenario.

In (1) base scenario, it was assumed that only existing nuclear power plants and those under construction will operate for 60 years, and that 23 reactors (23.7 GW) will remain in 2050. Only domestic storage was considered for CO_2 storage capacity through CCS, and the median value was set as 180 million t-CO_2/year, taking reference from the domestic storage capacity of 120–240 million t-CO_2/year set out in Japan's CCS Long-term Road Map Intermediate Summary[6]. Fuel prices were set based on the Sustainable Development Scenario (SDS) in the International Energy Agency's (IEA) World Energy Outlook 2021[7] (solid lines shown in Fig. 2).

Next, the (2) no nuclear scenario was assumed to be the scenario in which no nuclear power was used, based on the base scenario. In the (3) low CCS scenario, it was assumed that adequate CO_2 storage capacity cannot be secured due to geographical factors and other reasons, so CO_2 storage capacity was set at 60 million t/year, equivalent to one-third that of the base scenario. In (4) high fuel price scenario, it was assumed that fuel prices as of 2022 continue to increase till 2030, reaching twice the fuel price in SDS by 2050 (dotted lines shown in Fig. 2).

In all scenarios, hydrogen import price in 2050 was assumed to be 0.32 USD¢/ Nm^3-H_2, ammonia fuel price was assumed to be 447 USD/t, and the import price of synthetic methane was assumed to be 157 USD/toe.

Table 1 Case setting

<table>
<tr><th></th><th>Nuclear power</th><th>CO_2 storage capacity</th><th>Fuel price</th></tr>
<tr><td>(1) Base</td><td>Yes</td><td rowspan="2">180 million t/year</td><td rowspan="3">Based on WEO 2021</td></tr>
<tr><td>(2) No nuclear</td><td>No</td></tr>
<tr><td>(3) Low CCS</td><td rowspan="2">Yes</td><td>60 million t/year</td></tr>
<tr><td>(4) High fuel price</td><td>180 million t/year</td><td>Equivalent to twice that of WEO 2021 (2050)</td></tr>
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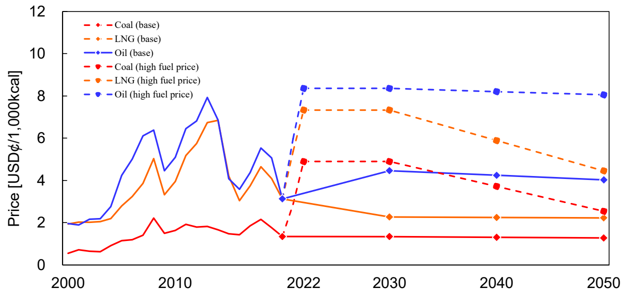

Fig. 2 Assumptions of primary energy fuel prices [USD¢/1,000 kcal]

3-2. Energy Service Demand

A total of 37 types of energy service demand (hereafter, "service demand") were considered: industry (steel, chemicals, cement, pulp and paper, other industries), transport (passenger, cargo), household (lights, cooling, heating, cooking), and business (lighting, cooling, heating, cooking). In the model, service demand in each department was further subdivided. For example, transport (passenger) was subdivided into five categories: passenger cars, buses, ships, rail, and aircraft.

Service demand to 2080 was estimated recursively based on forecasts of per capita GDP and other factors. Taking the example of steel production, for instance, GDP by industry was used as the explanatory variable to predict steel production volume into the future (horizontally after 2030). Table 2 shows the estimation results for the representative forms of service demand. GDP and population in the table are explanatory variables for the regressive prediction of some service demand, and are shown for reference.

Electricity demand and heat demand were determined endogenously through the amount introduced for each technology selected to fulfill the respective forms of service demand. For example, in the case where an electric furnace is selected for steel production, electricity demand in the model increases accordingly.

Table 2 Main types of service demand and macro assumptions

	Unit	2019	2030	2050
Steel production volume	Million t	98.4	90.4	90.4
Ethylene production volume	Million t	6.28	5.70	6.20
Cement production volume	Million t	58.1	5.56	5.96
Paper production volume	Million t	25.0	21.6	23.2
Passenger car transport volume	Billion people・km	90.96	83.02	68.74
Truck transport volume	Billion t・km	21.54	23.16	27.68
Real GDP (2015 as base year)	Trillion USD	5.51	6.65	9.30
Population	billion people	1.26	1.18	1.03

3-3. CO_2 Capture and Storage Technologies

For CO_2 capture, pre-combustion and post-combustion capture, and direct air capture (DAC) were used in this study. Pre-combustion capture was assumed to be installed in IGCC or coal gasifier, etc. based on the physical absorption method, while post-combustion capture was assumed to be installed in gas-fired power generators or blast furnaces, etc. based on the solid absorbent method. For all capture technologies, both the cases of installation in existing plants, assumed to be modified, and installation in new plants, were considered.

Total capital cost of CO_2 capture and O&M costs in 2050 were assumed to be 9.52 USD/(t-CO_2/year) (pre-combustion capture), 7.81 USD/(t-CO_2/year) (post-combustion capture), and 41.1 USD (t-CO_2/year) (DAC) (including CO_2 compression and liquefaction costs), taking reference from various sources[8), 9)]. Power consumption in CO_2 capture was assumed to be 355 kWh/t-CO_2 (pre-combustion capture), 184 kWh/t-CO_2 (post-combustion capture), and 1,316 kWh/t-CO_2 (DAC). CO2 storage cost, including CO2 transport cost (domestic transport, 300 km) was assumed to be 49.6 USD/t-CO_2, taking reference from various sources[10), 11)]

3-4. Upper Limit of Solar and Wind Power Installation

The capital costs of solar and wind power generation were estimated through the learning curve based on the premise that production costs fall with cumulative production volume, based on the capital costs estimated by the 2021 Power Generation Cost Verification Working Group / Procurement Price Calculation Committee, etc. With regard to solar power generation, capital costs were ranked in three tiers in consideration that capital costs vary depending on the scale of installation, and taking reference from the top 15%, 50%, and bottom 15% of the capital costs set out by the Procurement Price Calculation Committee.

The values for capital costs in 2050 were assumed to be 1,060–1,440 USD/kW (ground-mounted solar power system), 1,270–2,370 USD/kW (solar power system installed in buildings), 3,020 USD/kW (onshore wind power system), 3,360 USD/kW (fixed-bottom offshore wind power system), 4,370 USD/kW (floating-type offshore wind power system).

The upper limit on the amount of ground-mounted solar power and wind power introduced was estimated using GIS data as of April 2021, following the reference sources[12), 13)] and under the premise that power generation facilities are installed in places where the impact on the natural environment is considered to be small, such as weed land, bamboo-covered land, bare land, and desolate farmland that is difficult to regenerate, and in seas that are targeted as Project Promoting Zones based on the Act on Promoting the Utilization of Sea Areas for the Development of Marine Renewable Energy Power Generation Facilities, and assumed to be 65.4 GW for ground-mounted solar power systems, 23.4 GW for offshore wind power systems, and 405.1 GW for onshore wind power systems. The amount introduced for solar power generation systems installed on buildings was assumed to be 166.9 GW for systems installed on detached houses and 288.3 GW for systems installed on other buildings, taking reference from the Ministry of the Environment[14)]

4. Results of Technology Selection in 2050

4-1. Passenger Car Transport

To verify the status of energy technology introduced in each scenario, the passenger car transport volume, which is one of the forms of service demand, was taken as one example. The number of passenger cars owned in 2050 is shown in Fig. 3.

The passenger cars selected for this study were gasoline vehicles, plug-in hybrid vehicles, hybrid vehicles, electric vehicles, diesel vehicles, fuel cell vehicles, biofuel vehicles, and CNG vehicles. However, assuming that there is a given number of users travelling long distances, for electric vehicles which are assumed to have a short cruising distance and the amount introduced was limited to no more than 80% of all vehicle types.

From among these vehicles, gasoline vehicles (costing 21,200 USD per vehicle) or electric vehicles (costing 22,400 thousand USD per vehicle) were selected based on the premise of using DAC, taking into account power prices (marginal cost of electric power under the model) that vary depending on car prices, fuel prices, region, time period, and other factors.

Focusing on the differences between each scenario, in the low CCS scenario, the results showed that more electric vehicles are introduced in comparison with the other scenarios and greater electrification is carried out. This is because while it is more cost-effective to combine DAC with gasoline vehicles than with electric vehicles under the conditions of the assumed car prices, fuel prices, and marginal cost of power in 2050 which is the model solution (low CCS scenario: Region/Annual average of 16.3 USD¢/kWh), electric vehicles that have a relatively higher cost are introduced due to the strict constraints of CO_2 storage capacity in the low CCS scenario.

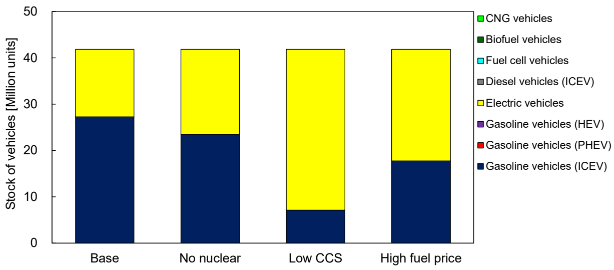

Fig. 3 Number of passenger cars owned in 2050 [Million units]

4-2. Power Sector

Fig. 4 shows the amount of power generated in 2050. The results show that in the base scenario, approximately 50% of all power generated is covered by renewable energy, while the remaining 50% is covered by nuclear power, gas-fired thermal power with CCS, and ammonia/hydrogen thermal power.

In the no nuclear scenario, more offshore wind power is introduced than nuclear power in comparison with the base scenario, and renewable energy ratio is approximately 70%. In the low CCS scenario, the introduction of DAC is suppressed due to CO_2 storage capacity constraints, and power consumption using DAC is reduced. For this reason, overall power generated is lower than in the other scenarios. Moreover, as CO_2 storage by CCS installed in gas-fired thermal power is also constrained, more ammonia/hydrogen thermal power is introduced in place of thermal power with CCS. In the high fuel price scenario, more offshore wind power is introduced in place of some gas-fired thermal power, and renewable energy ratio is approximately 70%.

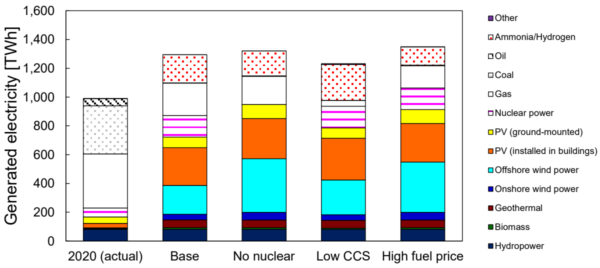

Fig. 4 Generated electricity in 2050 [TWh]

4-3. CO_2 Storage Capacity

Fig. 5 shows the breakdown of CO_2 storage volume in 2050. In the same figure, the red line shows the upper limit of CO_2 storage capacity given as the constraint condition, showing that in all scenarios, CO_2 is stored up to the upper limit of storage capacity.

In the base scenario, no nuclear scenario, and high fuel price scenario, about half of all CO_2 stored is captured through DAC, and CO_2 in the transport sector and CO_2 from boilers in the industrial sector, etc. are captured through DAC.

In the low CCS scenario, CO_2 storage primarily from gas-fired thermal power and biomass thermal power are prioritized, and the ratio of DAC to all CO_2 storage is relatively smaller compared to the other scenarios.

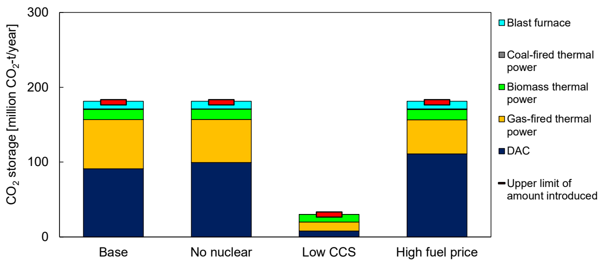

Fig. 5 Breakdown of CO_2 storage in 2050 [million CO_2-t/year]

5. MAC Evaluation Results

5-1. Shadow Prices of CO_2 Emission Constraints

Fig. 6 shows the changes in the shadow prices of CO_2 emission constraints when CO_2 emission constraints are assumed to be 680 million t-CO_2 in 2030 (46% lower than FY2013), 340 million t-CO_2 in 2040, and 0 t-CO_2 in 2050, across the four hypothetical scenarios.

The shadow price of CO_2 emission constraints in the base scenario and no nuclear scenario was estimated to be 574

USD/t-CO_2. Shadow price in the low CCS scenario was 743 USD/ t-CO_2, the highest among the four scenarios examined. Shadow price in the high fuel price scenario was the lowest among all the scenarios at 478 USD/ t-CO_2. However, the costs for additional reduction of CO_2 seem small due to the smaller cost difference between conventional fossil fuel-based technologies that discharge CO_2, and low-carbon technologies.

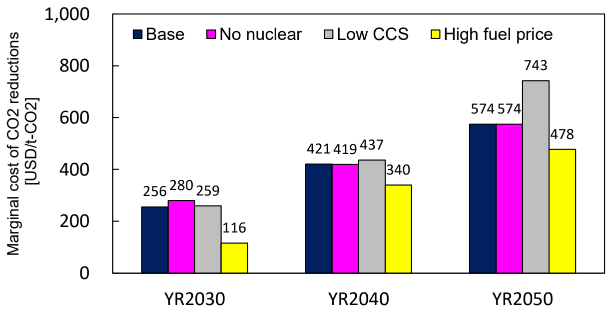

Fig. 6 Shadow prices of CO_2 emission constraints [USD/ t-CO_2]

5-2. Factors Determining MAC in the Base Scenario

Two types of calculations were performed for the base scenario: the case in which CO_2 emission constraints in 2050 was assumed to be 0 t-CO_2, and that in which it was assumed to be 1,000 t-CO_2. Based on the differential in the amount of each type of technology introduced in the respective scenarios, an analysis was carried out on the facilities, costs, etc. that are additionally introduced in the reduction of the final 1,000 t-CO_2 to achieve zero CO_2 emissions (Fig. 7).

The result of the analysis confirmed that in the base scenario, an additional 14 million toe of synthetic methane is imported to achieve the additional reduction of the final 1,000 t-CO_2. The additional combustion cost for this synthetic methane, divided by the amount of CO_2 reduction (1,000 t-CO_2), is 888 USD/ t-CO_2. The amount of LNG imported falls as a result of this additional import of synthetic methane, and LNG import costs also fall accordingly. Furthermore, it was confirmed that the amount of DAC introduced that consumes power also falls due to the fall in the consumption of LNG that discharges CO_2 into the atmosphere, and the amount of ammonia fuel imported for power generation purposes also falls. In this way, while synthetic methane is additionally introduced to discharge the final 1,000 t-CO_2 in the base scenario, MAC is determined through the interaction of various technologies.

Based on this, the cost after subtracting the decrease in these costs from the increase in synthetic methane fuel costs was 574 USD/t-CO_2, which generally matched the shadow price of the CO_2 emission constraints evaluated in Section 5.1. Hence, the differential calculation method examined in this study is effective in clarifying the factors determining MAC.

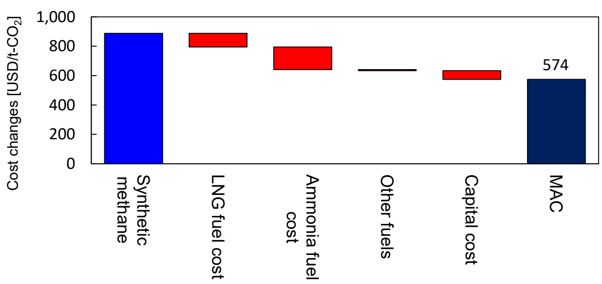

Fig. 7 Changes in technology introduced and fuel costs in the differential calculation method (base scenario, 2050) [USD/t-CO_2]

5-3. Differences in Determining Factors of MAC in Each Scenario

To see the differences in the determining factors of MAC in each scenario, an analysis was carried out on the facilities, etc. additionally introduced to achieve the final 1,000 t-CO_2 reduction in the low CCS scenario, for which MAC was the highest in 2050 (Fig. 8).

The result of the analysis confirmed that primarily DAC is introduced additionally (922 t-CO_2) to achieve an additional reduction of 1,000 t-CO_2 in the low CCS scenario. However, as the CO_2 storage capacity shown in Figure 5 has reached the upper limit, in order to store CO_2 through DAC under the model, CO_2 storage volume is reduced through gas-fired thermal power with CCS, and gas-fired thermal power with CCS is replaced by ammonia thermal power. It was also confirmed that reduction of the remaining 78 t-CO_2 is achieved through the introduction of electric vehicles and other means. Based on this, the value obtained by subtracting the cost of gas-fired thermal power, etc. from the additional costs of DAC and ammonia thermal power, etc. was 728 USD/t-CO_2, which generally matched the shadow price of the CO_2 emission constraints.

Here, focusing on the amount of natural gas supplied in primary energy supply, it would be 45 Mtoe in the base scenario, of which CO_2 is captured during combustion through CCS for 16 Mtoe, and through DAC for the remaining 29 Mtoe. On the other hand, the amount of natural gas supplied in the low CCS scenario is 6 Mtoe, and CO_2 is captured during combustion through CCS for almost all of the natural gas. The consumption of natural gas is suppressed in the low CCS scenario and room for CO_2 reductions through synthetic methane is limited. For this reason, it is supposed DAC is introduced instead of synthetic methane to achieve the final 1,000 t-CO_2 of reduction.

Based on the same method as used so far, the factors determining MAC across all four hypothetical scenarios were analyzed, and the results are shown in Fig. 9. The results showed that while synthetic methane is additionally imported in the base scenario and no nuclear scenario to achieve the final 1,000 t-CO_2 reduction, cost increases significantly in the low CCS scenario and high fuel price scenario due to an increase in the amount of ammonia fuel imported. The identification of detailed factors for this increase in the amount of ammonia fuel is an issue to be reviewed in the future, and is believed to be related to DAC as mentioned previously.

In the high fuel price scenario as well, the increase in the amount of ammonia fuel is a factor determining MAC and is also believed to be related to the additional introduction of DAC (698 t-CO_2). In this scenario, the introduction of renewable energy in place of gas-fired thermal power advances due to soaring fuel prices (Fig. 4), and the price of power consumed through DAC is reduced. The regional/annual average marginal cost of power in this scenario was 16.1 USD¢/kWh, which was the lowest in comparison with the other scenarios (base scenario: 17.0 USD¢/kWh, no nuclear scenario: 16.6 USD¢/kWh, low CCS scenario: 16.3 USD¢/kWh). For this reason, to achieve the last 1,000 t reduction, it is more economical to additionally introduce DAC rather than import synthetic methane, and it is inferred that DAC is a factor determining MAC.

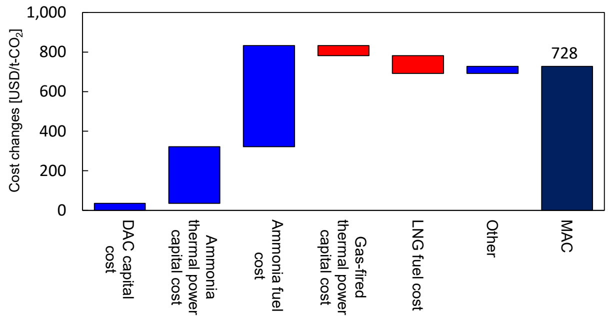

Fig. 8 Changes in technology introduced and fuel costs in the differential calculation method (low CCS scenario, 2050) [USD /t-CO_2]

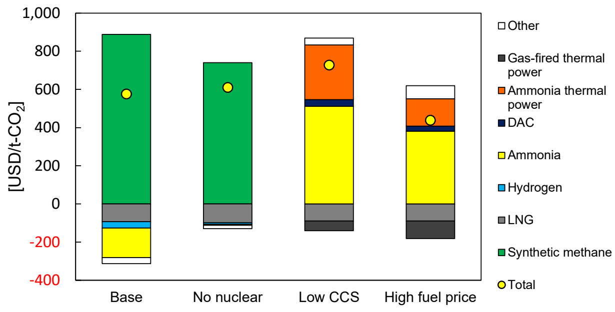

Fig. 9 Analysis of factors determining MAC in 2050 [USD/t-CO2]

6. Conclusion

This used the differential calculation method to evaluate the factors determining MAC in the case where net CO_2 emissions are assumed to be 0 t-CO_2 in 2050. This clarifies the factors determining MAC more effectively compared to the method of estimating MAC through the shadow prices of CO_2 emission constraints. Under the specific scenarios established in this study, it was confirmed that synthetic methane, DAC, etc. are factors determining MAC. However, to reduce MAC toward the realization of carbon neutrality, it is also helpful to consider reducing infrastructural costs and power costs associated with technologies that determine MAC, in addition to the cost reduction from such technologies. Moreover, for technologies with particularly high MAC, it may also be necessary to review policies that promote technological innovation, such as R&D.

In this study, while the MAC for achieving 0 t-CO_2 emissions in 2050 and its determining factors were identified, evaluation based on the differences in target years and CO_2 emission constraints is an issue. Moreover, clarifying the hierarchical relationship of technology introduction costs, estimated based on assumptions and model calculation results, will also be important in the future. Through these studies, we expect to be able to identify the important technologies corresponding to the levels of CO_2 emission reductions.

In policy evaluations, etc. to date have also referred to evaluations using cost indicators such as MAC, it is important to clarify the calculation process. This study anticipates that this will contribute to the review of measures toward the promotion of important technologies in the large-scale reduction of CO_2 as well as concrete measures to reduce MAC.

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A Study on Decarbonization Roadmaps for ASEAN Countries◆

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Abstract

In this study, we applied a liner programming model to the 10 ASEAN countries, and showed cost-optimal results for sectoral CO_2 emissions, primary energy supply, and power generation to decarbonize the region by 2060. We found that, as pointed out in IPCC AR6, (1) energy efficiency and electrification in the final consumption sectors, (2) early decarbonization in the power sectors (by 2040), and (3) utilization of negative emission technologies (DACC, BECCS and natural carbon sink) are also important for the region. In addition, it was confirmed that natural gas will play an important role in the transition period such as 2030 and 2040. Under our standard assumptions, not only renewables such as solar PV, but also thermal power such as natural gas with CCS and hydrogen/ammonia will be essential in many countries. Although decarbonization inevitably leads to an increase in the total cost of the energy system, it is possible to reduce the cost considerably by strengthening resource-sharing within ASEAN (e.g. via the international power grid) and technological innovation including demand-side technologies.

Key words: ASEAN, decarbonization, roadmap, liner programming model, hydrogen

1. Introduction

Since COP26, the wave of decarbonization has spread beyond developed nations to emerging and developing countries. Many of the countries in ASEAN have already declared that they will achieve carbon neutrality (CN) by around the middle of this century, including Indonesia by 2060 and Thailand by 2050. Reducing CO_2 emissions in such an ambitious way will require a fundamental transformation of the energy system, but at the same time, energy transition cannot be achieved with a one-size-fits-all approach. First, the existing ASEAN energy systems have a high dependence on fossil fuels: the share of fossil fuels in the primary energy supply of ASEAN as a whole is 80%. Vietnam is one country with a high share of coal, at 50% of primary energy supply. In addition, the potential of solar PV and wind power is unevenly distributed across the ASEAN region. Countries located closer to the equator, such as Indonesia, especially have relatively lower wind resource potential. Moreover, given the remarkable economic growth of ASEAN countries and fast-rising energy demand, it goes without saying that the decarbonization roadmaps of ASEAN countries cannot be realistic unless they fully reflect these circumstances.

Therefore, using a technology selection model that has been proven in analyzing Japan, the authors conducted an analysis aimed at describing cost-optimized decarbonization roadmaps in 10 ASEAN countries. The results of the analysis contributed to one of the five pillars of the Asia Energy Transition Initiative (AETI)[1)] founded by then Minister of Economy, Trade and Industry, Hiroshi Kajiyama, "Support for the development of energy transition roadmaps" and were reported to the Asia Green Growth Partnership Ministerial Meeting (AGGPM) Public-Private Forum (March 14, 2022)[2)] and ASEAN-

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Japan Business Week 2022 (May 30 to June 3, 2022)[3]. A research project report[4] was also published on the ERIA website.

Hereafter, charts use the following abbreviations for the names of countries and regions. BRN: Brunei, KHM: Cambodia, IDN: Indonesia, LAO: Laos, MYS: Malaysia, MMR: Myanmar, PHL: Philippines, SGP: Singapore, THA: Thailand, VNM: Vietnam.

2. Methodology

2-1. Model and assumptions

In this study, we applied the linear programming technology selection model[5] - which was used in analyzing Japan and reported in the Strategic Policy Committee[6),7)] - to 10 ASEAN countries. This model estimates a combination of technologies that minimizes the discounted total cost of energy systems for the entire target period and region, given the demand for energy services. It should be noted that this is a dynamic optimization across ASEAN as a whole, rather than by country. Data that is necessary in addition to energy service demand includes energy prices, resource endowments, and technical specifications (capital costs, operation and maintenance costs, efficiency). Table 1 shows the framework of the analysis.

Since each of the ASEAN countries is modeled as a single node, energy interchange within ASEAN (such as cross-border transmission lines) is explicitly considered. The model can calculate power supply and demand at up to as often as hourly, but in this analysis it was set to 4-hour intervals to save calculation time. Calculations were also performed at one-hour intervals during model development, but no significant difference was found in the optimal solution (this does not guarantee that there is no difference in the results of the case shown in this analysis). More than 350 technologies were envisioned, with consideration given to renewable energy (solar PV, onshore wind, offshore wind, hydro, geothermal and biomass) and nuclear power (light water reactors), CCUS (CCS, methane synthesis, Fischer-Tropsch (FT) synthesis), hydrogen and ammonia supply technologies (electrolysis, coal gasification, methane reforming, ammonia synthesis, direct importation from outside ASEAN, etc.), consumption technologies (power generation, fuel cell electric vehicles (FCEVs), hydrogen-based direct reduction steelmaking, hydrogen ships and aircraft, industrial heat utilization, etc.), and negative emission technologies (direct air capture with carbon storage (DACCS) and bioenergy with carbon capture and storage (BECCS)). For the use of hydrogen and ammonia in power generation, co-firing technologies were included in addition to single-firing technologies: coal-ammonia co-firing (mixed combustion ratio 20%) and gas-hydrogen co-firing (mixed combustion ratios of 20%, 40%, 60%, 80%)). The final consumption sector was modeled mainly based on the IEA energy balance tables[8], and references were also made to the literature on steel[9] and cement[10].

Table 1 Framework of analysis

Region	10 countries of ASEAN (10 nodes)
Years	2017, 2030, 2040, 2050, 2060
Discount rate	8%
Electricity supply/demand resolution	4-hourly intervals (2,190 hours per year)
Final consumption sector (services)	・ Industry (steel, cement, chemicals, pulp and paper, other industries) ・ Transport (cars, trucks and buses, rail, aviation, shipping, other transport) ・ Residential (lights and appliances, cooling, hot water, cooking) ・ Commercial (lights and appliances, cooling, hot water & cooking) ・ Other (agriculture, other demand)

For the input data, future demand for energy services was set based on the forecasts of ERIA[11] and IEEJ[12]. For future coal and gas prices, current domestic prices (coal: Indonesia, gas: Thailand) were extended with the Sustainable Development Scenario (SDS) in the IEA World Energy Outlook 2020[13]. Imported hydrogen and ammonia prices were based on the Japanese government targets[14] of 25 cents and 17 cents per 1 Nm^3-H_2, respectively in 2040, 20 cents and 16 cents in 2050, and 17.5 cents and 16 cents in 2060. Technical specifications are assumed based on various literature, and technical costs are set for each country where data is available, such as power generation technologies. Table 2 gives one case of assumed technology capital costs.

Table 2 An example of technology capital cost assumptions (Indonesia)

	2017	2030	2040	2050	2060
Solar PV ($/kW) [15]	790	560	485	410	382
Lithium-ion battery ($/kWh) [16]	370 (2020)	208	182	156	135
Direct air capture ($/t$CO_2$/yr) [17]	2,776	1,735	1,041	694	620

Note: Real 2019 prices.

Regarding the main constraints excluding CO_2 emission constraints, the upper limits of solar PV installation (3,513GW for ASEAN), onshore wind installation (313GW for ASEAN) and offshore wind installation (1,241GW for ASEAN) were set taking into account geographical and land use conditions, based on GIS data (Table 3). On solar PV, for example, forested land and land sloping at over 4% were excluded as unsuitable. The upper limit of the geothermal (34GW) and biomass power installation (71GW) were set based on various documents[18]. Here, it is assumed that the power generated by the solar PV, wind and hydro resources located in Indonesian territories outside of Java and Sumatra and Malaysian territories outside of the Malay Peninsula cannot be connected to power grids because these resources are separated from the centers of demand by the sea, but that they can be used for hydrogen production. Although there is significant political uncertainty about the introduction of nuclear power, for the purposes of this analysis, it might be introduced only in Indonesia (up to 35GW after 2050) and the Philippines (up to 0.63GW after 2050). Imports of hydrogen and ammonia from outside ASEAN are allowed from 2040 in our scenario, with import volumes capped at 15% of the total primary energy supply in each country's Baseline scenario (no emissions constraints) (5% in Indonesia) in 2040 and 30% after 2050 (7.5% in Indonesia). Regarding CCS, the annual upper limit of carbon storage for ASEAN as a whole, rather than by country, was set at 10 MtCO_2/year in 2030, 687 MtCO_2/year in 2040 (equivalent to 20% of energy-derived CO_2 emissions in the Baseline scenario), 1,138 MtCO_2/year in 2050 (25% of such emissions), and 1,610 MtCO_2/year in 2060 (30%). One report[19] assesses the cumulative CO_2 storage potential of Indonesia, Malaysia, the Philippines, Thailand and Vietnam combined to be about 75 GtCO_2, with the annual upper limit in 2060 equivalent to 2.1% of the potential. For the international power grid, the optimal installed capacity is determined within the model, but the upper limit was set based on current plans[20] (54GW for ASEAN as a whole). Note that in our standard assumption, electricity exports from Myanmar to Thailand are limited to zero.

Table 3 Upper limits of solar PV, wind and hydro installation (GW)

	BRN	KHM	IDN	LAO	MYS
Solar PV	2	350	1,493 (1,014)	89	195 (117)
Onshore wind	0	14	19 (13)	50	0
Offshore wind	0	2	224 (152)	0	0
Hydro	0	10	75 (55)	26	26 (20)
	MMR	**PHL**	**SGP**	**THA**	**VNM**
Solar PV	524	287	2	280	291
Onshore wind	1	92	0	70	66
Offshore wind	0	576	0	3	435
Hydro	100	4	0	6	35

Note: Values in parentheses ( ) are assumed usage for hydrogen production

2-2. Emission constraints and scenario setting

Constraints on energy-related CO_2 emissions are set for representative years and countries, with CN to be achieved in 2060 for ASEAN as a whole (Fig. 1). Here, constraints on energy-related CO_2 emissions in Indonesia, Malaysia, Myanmar and Thailand were set accounting for CO_2 emissions from land-use change and forestry (LULUCF) (Table 4). Assumed CO_2 emissions in the LULUCF secotr are based on the long-term strategies of each country, NDCs and emissions inventories (for example, Indonesia is assumed to be at -300MtCO_2 from 2050). However, even countries with rich potential absorption resources such as forests have set energy-related CO_2 abatement targets of at least 50% compared to 2017 emissions. While the cost of forestation and reforestation is not zero, they are probably relatively low compared to the cost of reducing energy-related CO_2 emissions, at \$0–240/ tCO_2[21].

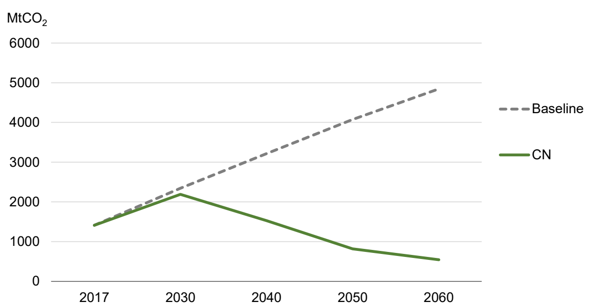

Fig. 1 Constrained energy-related CO_2 emissions (ASEAN)

Table 4 Year of CN achievement and energy-related CO_2 abatement targets (against 2017)

	BRN	KHM	IDN	LAO	MYS
CN year	2050	2050	2060	2050	2050
Reduction target	100%	100%	50%	100%	50%
	MMR	PHL	SGP	THA	VNM
CN year	2060	2060	2050	2050	2050
Reduction target	60%	100%	100%	50%	70%

The seven calculation scenarios are shown in Table 5. The Baseline scenario has no restrictions on carbon emissions, while the CN scenario does have restrictions. In addition, as a sensitivity analysis for the CN scenario, five scenarios by category (from PowerInov to Combo) are set in which further international cooperation (strengthened power grid across ASEAN) and technological innovations (reduction of various technology costs and raising the upper limit of annual CO_2 storage) are achieved.

Table 5 Scenario setting

Scenario	Salient features
Baseline	No constraints on carbon emissions
CN	Constraints on carbon emissions
PowerInov	・Capital cost of lithium-ion batteries reduced 25% by 2040, 50% from 2050 ・Cost of development of international power grid halved, unlimited development ・Exports from Myanmar to Thailand permitted
CCSInov	・Capital cost of DAC reduced 25% by 2040, 50% from 2050 ・Annual upper limit of CO_2 storage of 2.3GtCO_2/year in 2050, rising to 2.7GtCO_2/year in 2060
H2Inov	・Supply: 25% reduction in the capital cost of coal gasification, methane reforming, electrolysis and hydrogen tanks in 2040, a 50% reduction from 2050 ・Demand: 25% reduction in capital cost of hydrogen-based reduction steelmaking and fuel cell ships in 2040, a 50% reduction from 2050, and capital cost of FCEVs reduced to the same as hybrid electric vehicles in 2060
DemInov	50% reduction in the differential in capital costs between advanced technologies and the existing technologies from 2040 on the demand side (industry, transport, household)
Combo	A combination of PowerInov, CCSInov , H2Inov and DemInov

3. Findings and observations

3-1. Baseline and CN scenarios

As demonstrated in Fig. 2, which shows CO_2 emissions by sector for ASEAN as a whole, these will grow 3.4-fold from 2017 to 2060 in the Baseline scenario, reflecting the rise in energy demand in line with regional economic growth. Above all, emissions from the industry and transport sectors will rocket 4.6-fold and 4.5-fold, respectively. In the CN scenario, which aims for net zero CO_2 emissions across the whole of ASEAN by 2060 by reducing energy-related CO_2 with CO_2 absorption in the LULUCF sector, ASEAN approaches zero emissions from the power generation sector in 2040, and the sector turns into a source of negative emissions after 2050 as a result of BECCS. In addition, with the introduction of DACCS from 2050, BECCS and DACCS will combine to provide negative emissions of over 1GtCO_2 in 2060. Compared to the Baseline scenario, there will also be a large reduction in emissions from final consumption sectors, but the best solution for the remaining emissions, mainly from the transport sector (long-distance transport mainly by heavy-duty vehicles) and industry sector (demand for high-temperature heat) is to offset these with the negative emissions of the abovementioned BECCS, DACCS and the LULUCF sector. As such, the achievement of net zero through offsets with negative emissions while emissions continue from final consumption sectors that are hard to decarbonize is also consistent with the scenario of IPCC AR6.[21)]

Under the CN scenario, efficiency and electrification progress in final energy consumption, leading to a 17% reduction in total energy consumption from the Baseline in 2060, with 33% coming from electricity (Fig. 3). Oil consumption is half of Baseline in 2060, due to vehicle electrification, but consumption continues in large vehicles as noted above.

Looking at primary energy supply (Fig. 4, nuclear and renewable energy conversion rates in accordance with the IEA Energy Balance Table), the share of renewable energy will reach 38% in 2060 under the CN scenario, while imported hydrogen and ammonia will also account for 14%. If we check the 2060 supply-demand balance for hydrogen and ammonia here, supply is 73% imported, with electrolysis providing 24% and coal gasification 3%. On the demand side, power generation accounts for 85%, industrial heat utilization 9%, and fuel cell ships 4% - so in essence, the imported fuels will be used to generate power. As for natural gas, it is also selected as an important fuel in the power generation and industrial sectors under the CN scenario, and in the transition period of 2030 and 2040, the demand for natural gas will increase more than in the Baseline due to coal replacement. The recent spike in global gas prices is likely to have a significant negative impact on the ASEAN energy transition.

Power generation in the CN scenario is driven by demand from electrification of final consumption sectors and DAC (962TWh in 2060), a significant increase over Baseline and reaching a 6.5-fold increase over 2017 in 2060 (Fig. 5). As a result of efforts to minimize the cost of the overall energy system through optimal installation of batteries and thermal power generation in order to compensate for the intermittency of solar PV and wind power, which are to be adopted at scale (1,628GW in 2060), batteries will be installed on a large scale (1,365GWh in 2060) and the share of thermal power generation will remain at about 40–50%. Thermal power generation will shift from coal-fired power to gas-fired power and while applying low-carbon technologies such as hydrogen or ammonia co-firing, eventually decarbonizing in stages to gas-fired power with CCS or hydrogen or ammonia single-firing. However, the power supply mix in 2060 will vary greatly by country (Fig. 6). Myanmar, Cambodia and Laos have abundant resources compared to domestic demand, so renewable energy will account for more than 95% of their power generation. In 2060, 18% of Thailand's electricity demand will be covered by imports from Laos, with 65% of Laotian power generation exported to Thailand. In 2050, the capacity of the interconnector between Thailand and Laos will reach the upper development limit of 25GW. On the other hand, Malaysia, the Philippines, Singapore and Brunei will have less than one-third of their power generated by renewables. Malaysia does not benefit from great wind power resources, and most of the solar PV and hydro resources are concentrated on Borneo, where energy demand is low (Table 3). In this analysis, it was assumed that these resources could only be used for hydrogen production, but due to the cost advantage of imported hydrogen and ammonia, there will hardly be any domestic production.

Although the Philippines has abundant solar PV and wind resources, based on data supplied by the Philippine government, the cost of introducing wind power generation is higher than that of Indonesia, therefore little wind power is to be installed. In Singapore and Brunei, which have a small land area, gas-fired and hydrogen-fired thermal will be the main power sources.

Regarding the cost of CO_2 abatement, the marginal abatement cost under the CN scenario will be \$348/tCO_2 in 2060 (\$188–419 by country), and the additional cost from the Baseline case reaching 3.6% of GDP in 2060 (Fig. 7). The marginal abatement cost for ASEAN overall is calculated by applying the weighted average of the primary energy supply to the marginal abatement cost of each country. If we recall the current carbon tax rate in Sweden rate of \$130[22], the world's highest, then the cost burden is going to be significant on the path to CN. IPCC AR6 estimates that the global marginal abatement cost for CO_2 will be \$210 (\$140–340) in 2050 under the 2°C scenario and \$630 (\$430–990) (2015 prices) under the 1.5°C scenario, which is largely consistent with our analysis. Moreover, in our analysis, under the CN scenario, it was estimated that the marginal cost of electricity would double in 2060 compared to the base year (simple average of marginal cost over 2,190 hours per year). However, according to the IEA's net zero analysis[23], if the total energy burden of households is considered, electricity bills will increase while gasoline costs will drop to zero (due to the shift to EVs) and that therefore the share of energy-related expenditure in disposable income may not increase. It should be noted that decarbonization is certain to increase the cost of the entire energy system.

3-2. Innovation scenarios

Fig. 8 compares the power generation mixes under the CN scenario and the five innovation scenarios in 2060. The share of renewables under the PowerInov scenario maxes out at 76%, higher than the CN scenario (56%), due to higher solar PV and hydro generation. While the share of thermal power decreases, the capacity of batteries installed is 3.1 times higher than under the CN scenario. The removal of upper limits to the expansion of the international power grid allows 45% of power generation in the ASEAN region to be exported, correcting the uneven distribution of renewable energy resources in the region. By contrast, under the CCSInov scenario, the annual CO_2 storage capacity increases, lifting the share of gas-fired power (with CCS) to 36%. In both the PowerInov and CCSInov scenarios, there is less reliance on thermal power using imported hydrogen and ammonia and increased renewables and gas-fired power generation. In the H2Inov and DemInov scenarios, the power consumption of final consumption sectors will decrease due to the shift to hydrogen and efficiency improvements, while the introduction of DACs in electricity also decreases due to the reduction in oil as uptake of FCEV heavy vehicles increases. This means there is roughly 10% less power generated overall than under the CN scenario. In the Combo scenario, which is a combination of the four innovation scenarios, solar PV and gas-fired thermal increase compared to the CN scenario, but hydrogen, ammonia thermal and wind power, which are relatively high-cost, are practically eliminated.

Regarding the cost of CO_2 abatement in 2060 under the innovation scenarios, it is much lower than under the CN and Combo scenarios both in terms of marginal abatement and average abatement costs (Fig. 9). On the other hand, looking at the scenarios other than Combo, CCSInov has the lowest marginal abatement cost, while DemInov has the lowest average abatement cost - they are not the same scenario. For the DemInov scenario, this result may appear obvious as it predicts lower capital costs for a wide range of demand-side technologies from the outset, but it is not just a reduction in demand-side fixed costs for demand-side technology innovation, it also has significant knock-on effects on fuel cost and supply side fixed cost reductions. Given that the model's objective function is the minimization of overall costs, the minimization of overall costs is primarily the most important factor, but on the other hand, reducing marginal costs that are the basis of the market principle is also important. As we have seen here, it is important to remember that the two are not necessarily correlated.

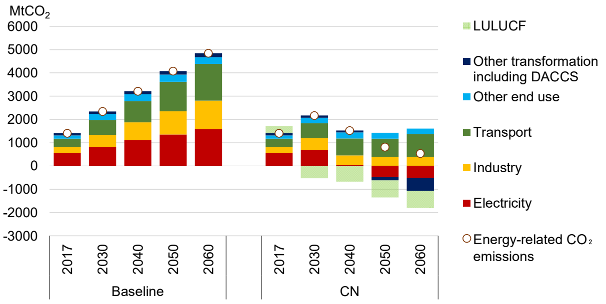

Fig. 2 CO_2 emissions by sector (ASEAN)

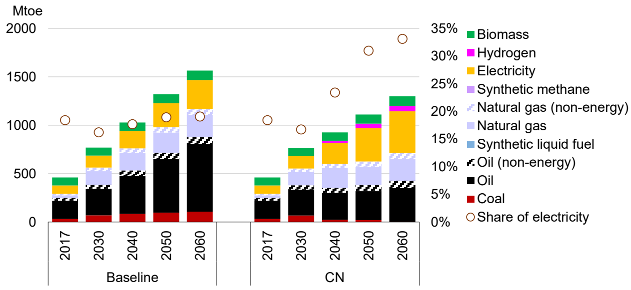

Fig. 3 Final energy consumption (ASEAN)

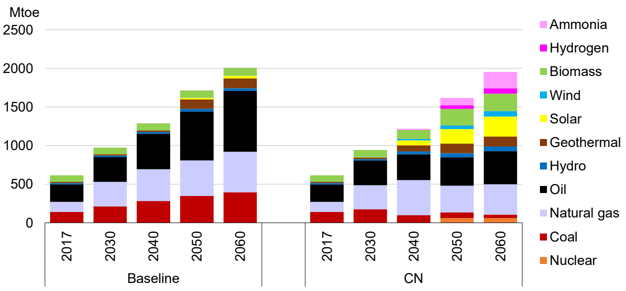

Fig. 4 Primary energy supply (ASEAN)

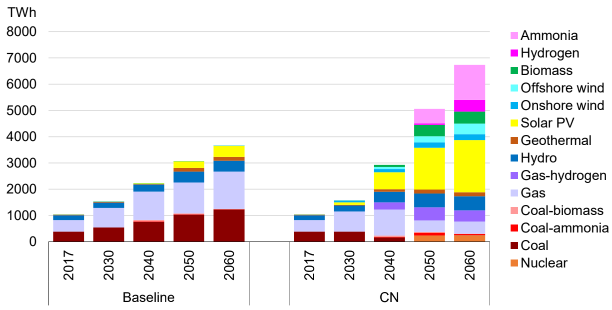

Fig. 5 Power generation (ASEAN)

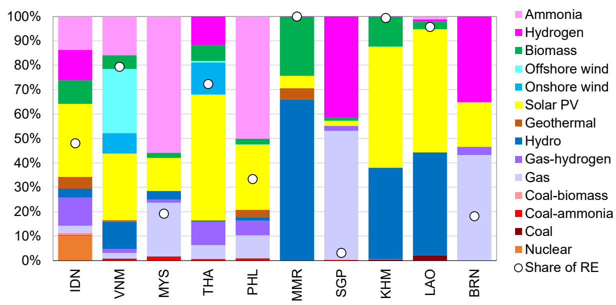

Fig. 6 Power generation share (CN, 2060)

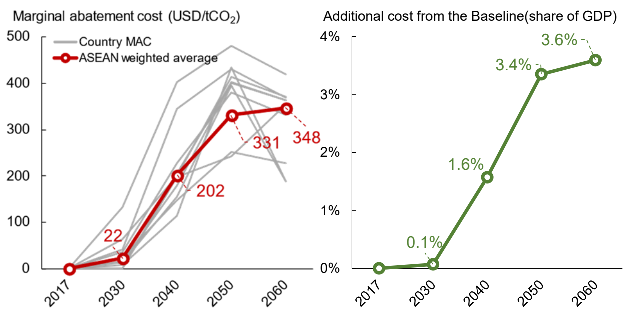

Fig. 7 Cost of CO_2 abatement (CN, ASEAN)

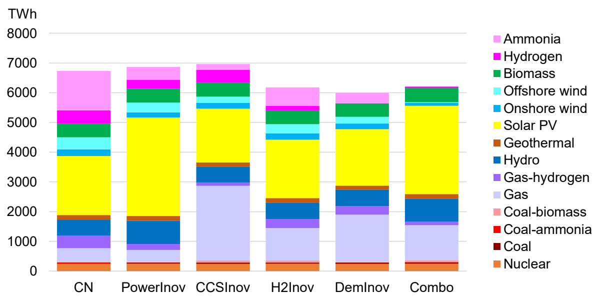

Fig. 8 Power generation under Inovation scenarios (ASEAN, 2060)

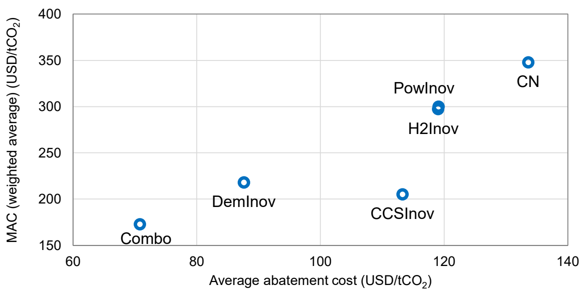

Fig. 9 Cost of CO_2 abatement under Innovation scenarios (ASEAN, 2060)

4. Conclusion

In this report on the 10 countries of ASEAN, we applied the linear programming technology selection model to demonstrate the cost-optimal solutions for CO_2 emissions by sector, primary energy supply and power generation mix toward achieving decarbonization. We found that as indicated by IPCC AR6, (1) energy efficiency and electrification in the final consumption sectors, (2) early decarbonization in the power sector (by around 2040), and (3) utilization of negative emission technologies (DACC, BECCS, forest carbon sinks) are also vital for this region. It was also confirmed that natural gas will play an important role in transition periods 2030 and 2040. Regarding the power supply mix, it goes without saying that renewables, especially solar PV, will be important, but gas-fired thermal power with CCS and hydrogen/ammonia-fired thermal power will also be indispensable in many countries. Although it is inevitable that the total cost of the energy system will increase with decarbonization, costs can be reduced considerably by strengthening natural resource sharing within ASEAN via the international power grid and achieving technological innovations, including on the demand side.

Acknowledgments

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U.S. Trade Policy for Solar PV Products: Tariffs on China◆

Daisuke Nakamori*

Abstract

The United States has high expectations for solar photovoltaic (PV) in the decarbonization plan. While China has established its dominant position in the global PV market, the U.S. has imposed trade tariffs on Chinese solar PV cells and modules to protect U.S. domestic PV manufacturers. This trade protectionism has increased the uncertainties in the U.S. solar PV market, creating a "Green Dilemma" over U.S. climate change policy. This paper explains the U.S. domestic political environment where domestic actors have been struggling to resolve this dilemma. The study shows how the institutional designs of U.S. trade laws and the diverse interests of stakeholders heighten the uncertainty of PV installation against the backdrop of a tougher U.S. stance toward China.

Key words: U.S., China, Solar Photovoltaic, Trade Tariff, Green Dilemma

1. Introduction

As climate change has become a central global theme, installing renewable energy is an urgent policy challenge. Notably, the relationship between the United States and China, the world's top investors in renewable energy and the largest energy consumers in 2021, will crucially determine the future of climate change[1). However, the decade-long U.S.-China trade dispute over photovoltaic (PV) cells and modules has shadowed this bilateral cooperation. The U.S. government has been imposing tariffs on solar PV products from China, the largest supplier of solar PV technologies. Controversially, tariffs have served as an obstacle to the supply of solar PV, one of the most promising renewable technologies in the U.S. After former President Donald Trump imposed additional tariffs, the U.S. almost ceased to import PV modules from China[2).

Such trade tariffs aim to protect domestic industries from competition against imported goods. Japan and Europe adopted similar measures in the solar PV sector in the 2010s. Although the governments would desire to import cheaper products from abroad to encourage renewable energy installations and decarbonize the power sector, the countries decided to impose tariffs to protect domestic industry. This paradoxical situation is called the "Green Dilemma"[3). The critics of the tariff's negative impact argue that the decline in solar PV module cost and policy incentives, such as tax cssssss and net metering, have partially offset the impact. However, the periodic reviews of tariff rates and the policy decision process over whether to continue the tariffs have heightened the uncertainty of the U.S. solar PV business. In 2018, the European Union lifted the tariff measures imposed on solar PV cells and modules from China in 2013 after considering the need for solar PV modules to achieve the EU's renewable energy targets in 2018[4).

The inauguration of President Joe Biden, who has stated climate change as one of his core priorities, raised hope for combating this dilemma; however, there has been no remarkable move after a year in office. Given the high expectations for solar PV in Biden's future power mix plan explained in the next section, the imposition of tariffs will likely lead to an undesirable outcome for the administration. Furthermore, the fundamental question arises if the current PV-dependent power mix plan remains achievable when the U.S. has imposed tariffs on China, the largest supplier of PV products from polysilicon to modules. This paper explores why the Biden administration, which has taken a significant step toward climate change combat, has failed to address this dilemma.

The outline of this paper is as follows. The next section reviews the prospects for solar PV deployment and the current PV module supply in the U.S. and overviews China's PV industry in the global context. The third section touches upon the outline of U.S. trade tariffs imposed during the Obama and Trump administrations amid the increasing concern over the precipitous growth of China's solar PV industry. The fourth section addresses why the Biden administration fails to ease the

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tension regarding tariffs, focusing on the institutional design of each tariff and the preferences of U.S. domestic actors. Based on the existing literature on anti-dumping duty (AD) and countervailing duty (CVD) initially imposed during the Obama administration, the fourth section focuses on the institutional characteristics of the safeguard measures (Section 201) and tariffs on goods from China (Section 301), both of which were initially imposed during the Trump administration under the Trade Act of 1974. The final section concludes the paper with a summary and policy implications.

2. Solar PV Industries in U.S. and China

2-1. U.S. Prospect for Solar PV in the Power Sector

The Biden administration announced its target to decarbonize the U.S. electricity sector by 2035. The U.S. Department of Energy (DOE) presented a scenario that the U.S. will need to produce 40% of its electricity from solar PV in 2035[5)]. Given that solar PV technologies accounted for about 3% of its power mix as of 2021, the U.S. will need to boost new solar PV installations at a rapid pace by 2035 and later. The DOE estimated that the annual PV installations need to reach 30 GW from 2021 to 2025 and 60 GW from 2026 to 2030. In 2021, the U.S. solar PV installations reached a record high of 23.6 GW. Biden's decarbonization efforts in the power sector, thus, primarily rely on a steady and massive supply of solar PV products.

2-2. Supply of Solar PV Products in the U.S.

Solar PV installations in the U.S. depend heavily on imports from abroad. U.S. manufacturers have ceased producing wafers and solar PV cells in the past decade. Among the PV-related products, the U.S. currently manufactures only solar PV modules made of crystalline silicon and thin films. The DOE reported that U.S. manufacturers produced approximately 14% of the PV modules supplied in the U.S. in 2020[6)]. The other modules are shipped mainly from Malaysia, Vietnam, and Thailand[7)]. Southeast Asian manufacturers are, however, dependent on Chinese polysilicon and wafers to produce solar PV cells and modules. Also, it has been pointed out that Chinese companies are deeply involved in Southeast Asia's solar PV businesses[8)]. In short, although U.S. dependence on Chinese PV products has decreased in direct trade, China's presence is still dominant if one watches the global PV supply chain.

2-3. China's Solar PV Industry in Global Context

China's solar PV industry began to develop in the 2000s. The solar PV cell and module manufacturers in China expanded their capacities for export to the center of demand, namely the U.S. and Europe, at that time. While China became a major exporter of solar PV products, accounting for approximately 40% of global PV cell production by 2009, domestic PV installations stalled in the 2000s due to inadequate policy incentives.

The external events, such as the 2008 financial crisis and tariff measures by other countries, heightened concerns about exports and turned China's focus on domestic PV installations[9)]. In addition, the 12th Five-Year Plan (2011-2015) defined green energy as a strategic emerging industry and spurred support for the PV industry. For these factors, China expanded the manufacturing capacity of PV products at a rapid pace throughout the 2010s.

Consequently, the Chinese solar PV industry has built a dominant position. As of 2020, China accounted for over 80% of the total manufacturing capacity in the global PV supply chain[10)]. Solar PV cell manufacturers outside China depend on Chinese wafers for cell production, as China monopolizes its production capacity. In 2021, China installed 54.9GW of solar PV panels, more than two-fold of the U.S. installment in the same year[11)].

3. U.S. Tariffs on Chinese Solar PV Cell and Module

3-1. Overview

As of 2022, the U.S. implemented three tariffs (AD and CVD recognized as one kind of tariff) on China's solar PV cells and modules (Figure 1). This section summarizes AD and CVD under the Tariff Act of 1930, the safeguard tariffs under Section 201 of the Trade Act of 1974, and the tariffs on goods from China under Section 301 of the Trade Act of 1974.

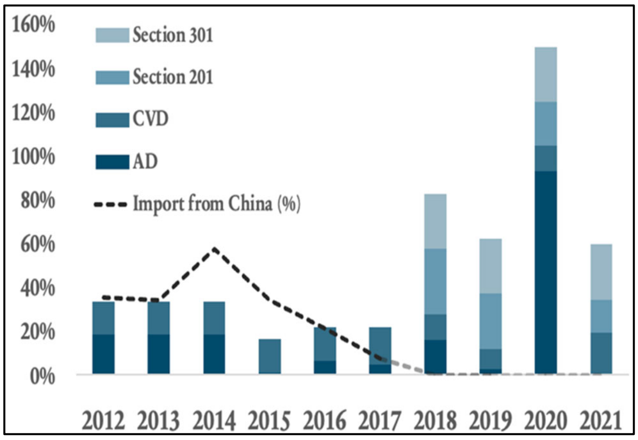

Fig. 1 U.S. Tariffs on Solar PV Cells and Modules from China (2012-2021)

Source: National Renewable Energy Laboratory

3-2. AD/CVD

In 2012, the U.S. Department of Commerce (DOE) announced the AD and CVD under the Tariff Act of 1930, targeting solar PV cells and modules from China. The AD provides relief to domestic industries injured or threatened by imported goods sold in the U.S. at prices that are less than fair market value[12]. The dumping margin, the percentage difference between fair value and dumped price, is charged as an AD tariff rate. Meanwhile, the CVD intends to provide relief to domestic industries injured or threatened by imported goods that receive government subsidies and can be sold at lower prices than U.S. equivalent goods. The AD and CVD measures set tariff rates for each targeted company; in 2012, the AD ranged from 18.32% to 249.09%[13], and the CVD ranged from 14.78% to 15.97%[14]. These rates are subject to periodic review.

The initial AD and CVD measures in 2012 exempted PV modules manufactured in China using non-Chinese solar PV cells from tariffs, which gave China an incentive to circumvent tariffs and thus reconsider its supply chain. This loophole of tariffs led to the increase of Chinese PV modules, consisting of solar PV cells made in Taiwan, in the U.S. market. To tackle this China's circumvention, the U.S. imposed the new AD and CVD tariffs that expanded the scope of coverage to the cells and modules made in Taiwan[15].

3-3. Safeguard (Section 201 Tariff)

In January 2018, the Trump administration announced the safeguard tariff on imported PV cells and modules under Section 201 of the Trade Act of 1974. The safeguard action provides import relief to the U.S. industry injured, or threatened, by increased import of goods[16]. The duration of safeguard measures is four years and can be extended to a maximum of eight years. The safeguard measures include not only the imposition of trade tariffs but also such options as tariff quotas and import quotas. The Trump administration adopted a tariff of 30% on solar PV modules and a 2.5 GW tariff-rate quota (TQL) on solar PV cells[17].

In February 2022, with the original measure faced with expiration, President Biden issued a Proclamation extending the safeguard measure[18]. The new safeguard measure, addressing the concerns about the domestic supply of PV products, exempt high demanded bifacial PV modules from the tariff and double TRQ for PV cells from 2.5GW to 5GW. The tariff on PV modules was 14.75%, less than half of the initial tariff rate in 2018.

3-4. China Tariff (Section 301 Tariff)

The Trump administration imposed the other tariff under Section 301 of the Trade Act of 1974. This symbolic move, "China Tariffs," reflected the worsening U.S.-China trade war. The Section 301 procedure provides relief to the U.S. industries threatened or injured by an unjustifiable, unreasonable, or discriminatory action. This sanction targets over 20,000 goods, including solar PV cells and modules imported from China[19]. Before the Trump Administration, the World Trade Organization (WTO) pursued dispute settlement when the U.S. used Section 301 authorities. However, Former President Trump, perceiving the WTO's settlement as insufficient to counter China, pushed for the U.S. unilateral action. The USTR published the list of targeted goods up to List 4. Solar PV cells and modules are subject to 25% tariffs[20].

4. Politics of Tariff Measures on PV Products

4-1. Domestic Actors in AD and CVD Processes

The domestic energy industry exerts significant influence in the U.S. energy policymaking process[21]. While the carbon-intensive industry, remarkably the fossil fuel sector, has been of great interest traditionally, the growing renewable energy industry, with the development of low-carbon technologies and increasing interest in climate change among politicians, came to exercise its influence on the political sphere[22]. As a prominent example, the renewable energy industry seeks protection from cheap imported goods and supports trade protectionism to a greater extent[23]. This trend caused the "Green Dilemma," in which the renewable energy industry, a major actor in decarbonization, stalls the domestic supply of renewable energy due to concerns about imported goods from abroad.

The Solar PV industry is no exception to this dilemma. The U.S. solar PV cell and module manufacturers have expressed concerns about the influx of cheap imports and have supported the tariffs since the Obama administration. The unique political environment occurs here as the U.S. PV industry is divided between pros and cons over tariff measures. On the pros side, the U.S. cell and module manufacturers favor tariffs on cheap imports from abroad to keep the competitiveness of domestic manufacturers. On the cons side, the installers and engineering companies, who benefit from installing PV modules, oppose the tariffs that increase the cost of solar PV module procurement[24].

The existing literature on AD and CVD pointed out that the petitioner for tariffs—PV cell and module manufacturers—had an advantage under the investigative processes by the United States International Trade Commission (ITC) and the U.S. Department of Commerce (DoC)[25]. In the investigative processes, the ITC pays particular attention to injuries or threats caused by imported goods. On the other hand, the DoC looks closely at the extent of damages the ITC found. Although the interested parties can assert their opinions through petitions and hearings, the final determination largely depends on whether the injuries to petitioners exist. This institutional characteristic makes it hard for the opponents of tariffs to reflect their concerns about the tariff's negative impact on the domestic economy and climate change in the final determination.

It is worth noting that the tariff measures under Section 201 and Section 301 of the Trade Act of 1974 have different institutional designs from AD and CVD. In the Section 201 process, the ITC takes responsibility for the investigation, and the President makes a final decision. The President's consideration covers a broader range of issues than AD and CVD. The President "must weigh U.S. national economic and security interests." The Section 301 actions are characterized by the executive branch's unilateral decision-making process. The law grants the United States Trade Representative (USTR) and the President authority to investigate trade barriers and implement retaliatory actions. The following parts analyze the Section 201 and 301 tariffs with a particular focus on the institutional designs and the interactions of stakeholders, compared with AD and CVD if necessary.

4-2. Safeguard

4-2-1. Institutional Design

The safeguard actions under Section 201 of the Trade Act of 1974 are initiated by a written petition claiming injuries to domestic industries caused by the influx of imported goods. The petitioners can be firms, interest groups, USTR, House Ways and Means Committee, Senate Finance Committee, or ITC. Once a petition is filed, the ITC investigates whether the affected U.S. industry is seriously injured or threatened with a severe injury. If that is the case, the ITC examines whether an increase in imports is a substantial cause of the injury. The injuries to be considered include: "the significant idling of production facilities; the inability of a significant number of firms to carry out domestic production at a reasonable output level; and significant unemployment or underemployment within the U.S. industry[26].” Unlike the AD and CVD investigations focusing on unfair trade practices such as subsidy and dumping, the safeguard process prioritizes whether increased quantities of imported are the substantial cause of serious injury or a threat to U.S. manufacturers[27]. If the ITC commissioners make an affirmative injury determination, the ITC sends remedy recommendations to the President.

After receiving the ITC’s recommendations, the President decides which recommendations to implement. The President may act in line with the recommendations, modify them, or do nothing. In doing so, the President must consider the national economic and security interests and the proposed remedy’s possible impact on U.S. consumers and other industries[28]. The Presidential actions include proclaiming a tariff, quota on imports, diplomatic negotiations, or submission of legislative proposals to Congress[29]. If the President decides differently from the ITC’s proposal or takes no action, Congress may enact a joint resolution of disapproval that, if enacted, makes the ITC’s recommendation a remedy.

4-2-2. Actors and Process

In 2017, Suniva and SolarWorld, two major solar PV module manufacturers in the U.S., filed a petition for the ITC’s safeguard investigation[30]. The two firms claimed that the influx of solar PV cells and modules caused the oversupply and price erosion of such products in the U.S. market, resulting in the shutdown of manufacturing facilities and creating an unprofitable situation. The petitioners argued that the influx of imported goods is the significant cause of injuries to domestic manufacturers. They, therefore, called for government protection to ensure U.S. competitiveness in the field of advanced technologies.

Opposing the petitioners’ claims, the Solar Energy Industries Association (SEIA), the national trade association for the U.S. solar and storage industry, expressed concern about the tariff’s negative impact on the PV industry, except for the cell and module manufacturers. SEIA stressed that the additional tariff would increase the PV installation cost and enhance the uncertainty of future investment decisions. In the ITC’s hearing, SEIA questioned the quality of solar PV products made by the petitioners and attributed the petitioners’ predicament to a lack of innovative effort to remain competitive with imported goods. Hence, the organization argued that the petitioners failed to meet the requirements for invoking the safeguard provisions[31].

Considering the claims from both sides, the ITC concluded that the increased quantities of imported PV cells and modules were the substantial cause of injuries to petitioners and reported its findings to the President[32]. The Section 201 investigative process by the ITC, as with the AD and CVD, focuses on the actual harm the petitioners suffered and examines if the damage comes from the increased quantities of imported goods. At the stage of ITC’s investigation, the commissioners did not institutionally consider the tariff’s negative impact as claimed by SEIA. In this regard, the ITC’s safeguard investigative process is more favorable to petitioners’ claims than other stakeholders’ claims.

The presidential action for implementing remedies makes the Section 201 process different from the AD and CVD. However, as mentioned above, Congress may enact a joint resolution of disapproval if the legislators find that the presidential report, which describes the action and its reasons, deviates from the ITC’s recommendations. The resolution, if enacted, turns ITC’s recommendations into remedy; that is, although the President can modify the ITC’s recommendations as specified in the law, the actions the President can take depend heavily on the ITC’s suggestions in practice. The safeguard actions initiated by the Trump administration, in fact, mostly followed the ITC’s recommendations—trade tariff and tariff quota—even though the presidential action adopted stricter remedies by targeting Canada that the ITC’s recommendations exclude[33]. To sum up, the Section 21 process grants the executive branch the right to propose a final remedy, but the contents of the presidential proposal largely depend on the ITC’s recommendations that strongly reflect the petitioners’ claims as with AD and CVD.

4-3. China Tariffs

4-3-1. Institutional Design

The USTR and the President take responsibility for the decision-making processes, such as investigation and remedy proposal, under Section 301 of the Trade Act of 1974. Unlike the other tariff processes, Section 301 does not require investigations by an independent agency (ITC). This characteristic raises questions about the transparency and consistency of the Section 301 process.

The USTR initiates its investigation when an interested person files a petition, or the USTR can self-initiate a case. The law requires the USTR to attempt to consult with a targeted foreign government upon initiating an investigation. The USTR examines whether the alleged conduct is unjustifiable and violates U.S. rights under the trade agreement. If the USTR's determination is affirmative, the USTR decides what action to take, if any, with the direction of the President[34]. The retaliatory action includes the imposition of trade tariffs, withdrawal from trade agreements, building new bilateral agreements, and so on. If the USTR takes import restrictions, trade duties (tariffs) must be the first option. The Section 301 actions terminate after four years if the USTR does not receive a request to continue the action.

4-3-2. Actors and Process

The "unfair trade practices" in Section 301 vary widely because of the breadth of the targeted industries. Regarding the solar PV industry, the US solar PV module manufacturer, SolarWorld, testified in the hearing and petitioned that China conducted cyber-attacks against the company and stole its intellectual property[35]. SolarWorld argued that the firm's business was in danger as Chinese solar PV modules became competitive in the U.S. market due to China's innovation in module production, driven by stolen information from the firm. The USTR showed that the stolen information helped Chinese products to enter the U.S. market at an incredible speed, costing SolarWorld about $120 million.

SEIA, as the organization did in the safeguard process, expressed concern about the SolarWorld's move by arguing that the new trade tariff would have a further negative impact on the U.S. solar industry[36]. SEIA stressed that the share of Chinese solar PV cells and modules already fell to roughly 1% due to the other trade mechanisms and therefore claimed that the Section 301 tariffs are unlikely to give significant leverage on China. SEIA also warned that further job losses in the U.S. PV market would happen due to Section 301 and stated that the AD and CVD investigations could be adjusted to the Chinese unfair trade practices.

The USTR findings concluded that China's cyber-attacks against SolarWorld were an unreasonable infringement of the intellectual property of the U.S. manufacturer and determined the imposition of additional duties on imported goods from China[37]. The cyber-attacks infringed on fair international trade based on international agreements, but the U.S. policy had failed to provide sufficient relief to the targeted U.S. companies, explained the USTR. The USTR also pointed out that the U.S. companies could not identify and recover legal costs by themselves, and thus China's cyber-attacks burden U.S. commerce. The USTR, however, does not address the possible impact of tariffs on the import status of Chinese goods and employment in the U.S. industry, as claimed by SEIA.

5. Conclusion

This paper tried to address why the U.S. has struggled with tackling the "Green Dilemma" situation by examining the institutional design of each tariff measure and the preferences of domestic actors. The previous sections showed that the current tariffs on China's solar PV products are based on three investigative processes. First and foremost, it is worth noting that the investigative processes, in common, are designed to give preferences to the petitions by the solar PV cell and module manufacturers in the U.S. In the AD and CVD processes, the ITC and DoC pay exclusive attention to the petitioners' damages caused by dumping and subsidy. The safeguard process includes the presidential decision that considers the impact of the tariff on national security and the economy, besides the ITC investigation. However, this presidential intervention (or recommendation) is institutionally limited to deviating from the ITC's recommendations that exclusively reflect the petitioners' claims. Amid bipartisan anti-China sentiment in Congress, the Section 301 process is more likely to have worked to the advantage of SolarWorld, a victim of China's unfair practice, than SEIA.

In summary, the U.S. tariffs on Chinese PV products are characterized by the fact that the small minority in the U.S. solar PV industry—cell and module manufacturers—have the leverage on final determinations. Also, it is striking that all three investigative processes explained in this paper lack consideration of the tariff's possible impact on climate change measures. Going back to the question, the divergence between the trade policy to protect the domestic industry and the climate policy to decarbonize U.S. power generation has made it challenging to deal with the "Green Dilemma." As climate change emerges as an influential agenda, the question of how the U.S. will respond to the tariffs on PV products as a domestic institutional issue, not limited to the problem with China, has important implications not only for the progress of solar PV installations in the country but also the development of overall climate change measures.

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DECARBONIZING ASIAN ECONOMIES WITH GREEN HYDROGEN

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DECARBONIZING ASIAN ECONOMIES WITH GREEN HYDROGEN

EXECUTIVE SUMMARY

Introduction

Hydrogen has gained global attention as a key breakthrough for decarbonizing hard-to-abate sectors. Low-carbon hydrogen can be produced from a wide range of resources. This diversity of sources enables hydrogen production almost anywhere in the world.

The ASEAN region is struggling to set and achieve ambitious decarbonization goals. The development of a green hydrogen economy in the ASEAN region can contribute to accelerated region-wide transition to clean and sustainable energy, and thus the decarbonization of the region's economy. However, the region has yet to harness its great potential for renewable power, much less green hydrogen production.

This study analyzes the potential of using green hydrogen produced in the ASEAN region to decarbonize sectors - hard-to-abate industries and transport - for which electrification is not the optimal solution.

Green hydrogen supply and demand potential in the ASEAN region

Based on IEA (2022b) and projections for 2050, potential hydrogen demand was determined by assuming that renewable power would be used in all sectors that can be electrified and that the remaining hard-to-abate applications would be covered by green hydrogen. High-temperature heat demand in the industry sector and part of the transport sector (heavy-duty vehicles, and air, maritime, and rail transport) were included in the study.

Despite energy efficiency improvements, energy consumption will increase significantly in both the industry and transport sectors in 2050, driven by economic growth. The potential hydrogen demand of the entire ASEAN region is 152 Mtoe, or 40% of total final energy consumption across the industry sector. The potential hydrogen demand in the transport sector across the entire ASEAN region is 166 Mtoe, accounting for 44% of final energy consumption in the transport sector.

Since increased renewable power deployment should be prioritized in the ASEAN region, potential hydrogen supply was evaluated under the assumption that renewable energy would primarily be used to replace fossil fuel-fired thermal power plants, only after which the remaining renewable power would be used to produce hydrogen. Based on the renewable energy potential provided in ERIA (2021) and IRENA & ACE (2022), the authors derived the regional potential for green hydrogen production.

Even under the assumption that renewable energy would cover both total power generation in 2050 and the additional power generation needed to accommodate further electrification demand in 2050 and beyond, surplus renewable energy is available for use in hydrogen production. ASEAN countries collectively have the potential to supply three times the potential hydrogen demand in 2050 (Figure). Therefore, even in the most pessimistic case, there is an ample potential supply of green hydrogen across the entire ASEAN region to cover regional hydrogen demand. Therefore, the intra-regional trade of green hydrogen could offer a solution to the challenge of region-wide decarbonization of hard-to-abate industries using local resources.

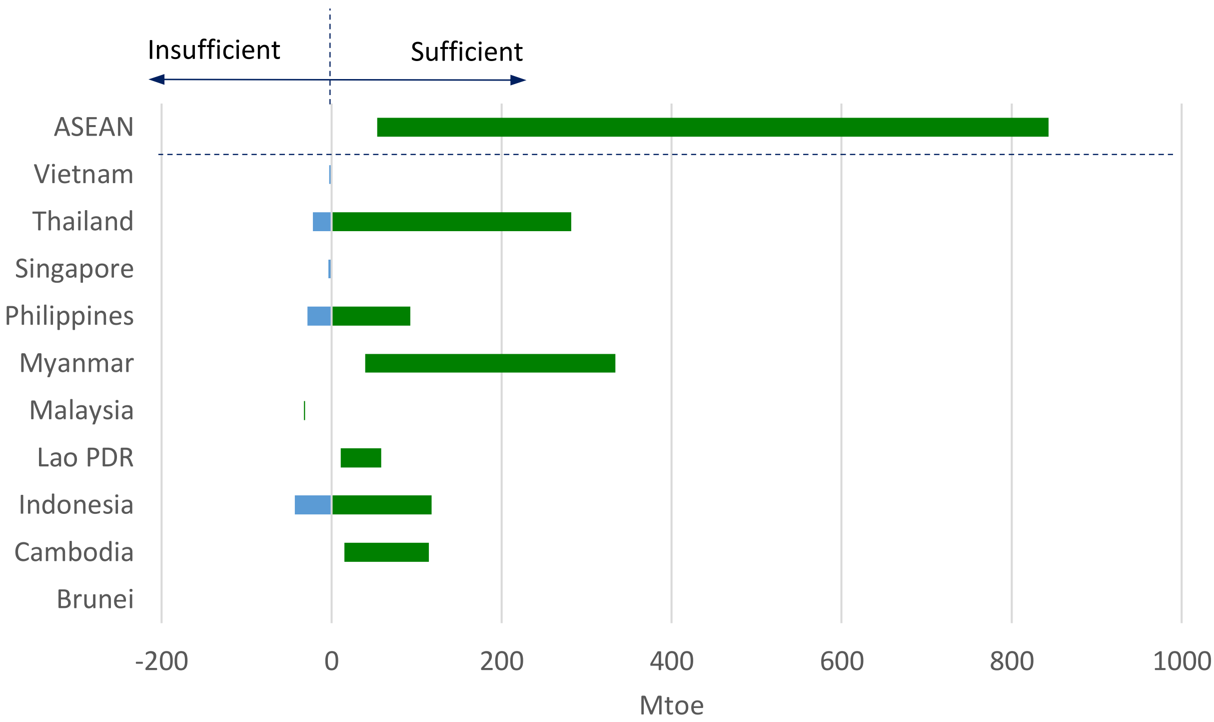

FIGURE. SUFFICIENCY OF POTENTIAL GREEN HYDROGEN SUPPLY (2050)

Opportunities and challenges for the ASEAN region

Green hydrogen production may change the geopolitics of the ASEAN region to some extent. Low-income economies, such as Myanmar, Lao PDR, and Cambodia, will have the opportunity to become the region's energy supplier. However, most ASEAN member countries have yet to develop national hydrogen strategies, or even include hydrogen in their national energy plans. Furthermore, there are various challenges to developing the full renewable energy potential of the region. These include the lack of financial support and channels, lack of experience and regulatory frameworks, insufficient coordination among government agencies, and limited infrastructure, such as grid enhancement needs for massive renewable integration. The power development plans and renewable power targets laid out by each country also fall substantially short of their renewable energy potential. Therefore, policy measures will need to be put in place to harness their full potential.

Home to very limited energy resources, Japan is likely to continue to be an energy importer even in the hydrogen era. The ASEAN region, given its proximity, is potentially a promising major supplier of green hydrogen for Japan, which aims to introduce 3 million tonnes of hydrogen in 2030 and 20 million tonnes in 2050. Not only is its proximity an advantage, but green hydrogen imports from the ASEAN region will also contribute to diversifying its energy imports, and thus serve Japan’s energy security.

Another consideration to be made is Singapore’s global importance as a bunkering hub, supplying almost 50 million tonnes of marine bunker fuel to vessels in 2021. A reasonable amount of regionally produced e-fuel can be collected in Singapore from across the ASEAN region. This can potentially offer large business opportunities for the ASEAN region.

Further promoting renewable energy development

For green hydrogen to be a realistic and optimal solution for decarbonizing the economy, the renewable power used in its production should be available in surplus, after being fully harnessed to decarbonize sectors whose carbon footprint can be lowered by using it directly. Therefore, investment should first be targeted at developing renewable energy. To support this, it is essential that polices are in place for the massive deployment of renewable energy in each country. This will help lower renewable power generation costs and in turn bring down green hydrogen production costs, which is most affected by power generation costs (IEEJ, 2021).

Japan’s role

Japan can play an important role in building and expanding the regional hydrogen market and thus bring costs down through close cooperation with ASEAN countries on hydrogen-related technology development. Since the renewable energy market is yet to be fully developed in some countries, players may be able to enjoy first-mover advantage in establishing the business environment for renewable energy, and in turn for hydrogen. Japan's experience with relevant infrastructure, transportation and storage technologies, laws and regulation, and safety standards can help develop ASEAN’s regional hydrogen market.

The year 2023 marks the “50th Year of ASEAN-Japan Friendship and Cooperation.” Japan has built many cooperation frameworks in place for supporting ASEAN countries’ energy transition. Under these frameworks, Japan can also support the designing of aggressive but feasible decarbonization policies with consideration of region-specific circumstances and needs. Such support could include technological and financial support, in-depth studies to reveal local challenges and solutions, support in formulating master plans based on such studies, and the implementation of stakeholder dialogue.

CHAPTER 1. BACKGROUND AND OBJECTIVES OF STUDY

Given the urgent call to globally reduce CO_2 emissions to net-zero by mid-century (IPCC, 2021), many countries in the ASEAN region are struggling to set and achieve ambitious decarbonization goals. Renewable energy and low-carbon hydrogen are key to decarbonizing their economies. The ASEAN region bears great potential for renewable power, including solar, wind, and hydropower. These resources can be used to produced green hydrogen, but this potential has yet to be sufficiently explored. The development of a green hydrogen economy in the ASEAN region can contribute to accelerating region-wide transition to clean and sustainable energy and raising its energy self-sufficiency, and in turn enhancing the region's energy security.

Low-carbon hydrogen can generally be produced from a wide range of resources. This diversity enables hydrogen production almost anywhere in the world. Yet, home to very limited energy resources, Japan will need to rely heavily on imports for hydrogen as well. Due to its proximity, the ASEAN region could promise to be a future supplier of hydrogen to Japan, depending on its potential.

In Japan, discussions on procuring hydrogen started in 2012, the year following the Great East Japan Earthquake, when the country was faced with challenges in decarbonizing its energy system, especially in terms of power generation. Japan continues to be challenged with social acceptance issues and land constraints in increasing nuclear power generation and massively deploying renewables. While Japan has made significant efforts to increase its renewable capacity, its critically low renewable energy potential stands out in the global context (IRENA, 2021b). Therefore, having considered hydrogen to be a breakthrough for decarbonization from a very early time, Japan was the first country in the world to formulate a national hydrogen strategy[1] and seeks to create hydrogen demand of approximately 20 million tonnes in 2050[2].

The recent enthusiasm of the Japanese government and private sector has been inclined towards importing blue hydrogen or blue fuel ammonia. However, this study will focus on green hydrogen for reason explained in Section 2.1.

This study will explore the ASEAN region's potential for using locally produced green hydrogen to decarbonize its economy, focusing on its application in industry and transport. It will also look at its potential to become a hydrogen exporter to areas outside the region, such as Japan.

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CHAPTER 2. SCOPE OF STUDY AND METHODOLOGY

2.1. SCOPE OF STUDY

This study analyzes the potential of using green hydrogen produced in the ASEAN region to decarbonize sectors in which electrification is not the optimal solution. These include hard-to-abate industries and parts of the transport sector.

The authors focus on green hydrogen, or hydrogen produced via water electrolysis using renewable energy sources, including solar power, wind power, hydropower, geothermal power, and biomass. Some ASEAN countries are home to fossil fuel resources and thus countries like Brunei and Malaysia currently host projects to build international supply chains for blue hydrogen, produced from fossil fuels but with the carbon generated during the process captured and stored. However, this study does not consider blue hydrogen despite its availability for several reasons:

First, given its smaller carbon footprint, green hydrogen will not be challenged by the increased market and political pressure against using fossil fuels. Second, the recent energy crisis has revealed challenges and disadvantages inherent to blue hydrogen. The price of blue hydrogen and its derivatives risk being affected by volatile market fossil fuel prices, which can surge as witnessed in the past year[3]. Skyrocketing oil and gas prices may make green hydrogen increasingly competitive and attractive, as renewable energy prices have consistently dropped regardless of oil and gas market trends. Third, renewable energy can be found in a wider area and thus any country can become a green hydrogen exporter by harnessing such resources. While blue hydrogen would be imported from oil and gas producing countries, green hydrogen supply chains can be more diversified, reaching beyond conventional energy exporters, and thus contribute to improving the region's energy security.

2.2. METHODOLOGY

2.2.1. POTENTIAL HYDROGEN DEMAND

Hydrogen can technically be used for a wide variety of applications. However, it is unreasonable to apply hydrogen when more cost-efficient solutions are available. Therefore, this study assumes that hydrogen will be used in "hard-to-abate" sectors that are difficult to decarbonize through electrification. Potential hydrogen demand was determined by assuming that all hard-to-abate applications would be covered by green hydrogen. The following hard-to-abate applications were

[3] For example, the Fuel Ammonia Supply Chain Public-Private Task Force, METI (2022) analyzed that when gas prices increase by USD0.5/mmbtu, ammonia prices increase by USD18/t-NH3.

considered: high-temperature heat demand in the industry sector; and heavy-duty vehicles, and air, maritime, and rail transport in the transport sector. Some past studies (e.g. ERIA, 2019) have given great consideration to using hydrogen in the power generation sector. However, the ASEAN region has yet to unleash its renewable energy potential and should prioritize renewable power deployment toward 2050. Only after the power generation sector has been decarbonized by renewable power, should surplus renewable grid power or unharnessed renewable energy be used for hydrogen production. Hence, this study did not consider hydrogen use in the power generation sector.

This study will evaluate potential hydrogen demand based on current final energy demand and projections for 2050 using the following methodology:

(1) Industry sector

i. Based on IEA (2022b), final energy demand in the industry sector in 2019 is identified for each ASEAN country by industry and by energy type.
ii. Based on an existing study (MRI, 2018), the share of high temperature (≥400°C) heat demand against total fossil fuel consumption is identified for each industrial sector (Table 1). Although MRI (2018) analyzes Japanese industry, this study assumes that the energy consumption structure in each industrial sector is not varied among different countries.
iii. Potential hydrogen demand is estimated by multiplying the total fossil fuel consumption in each industrial sector by the abovementioned sector-specific ratio. It should be noted that although heat demand comprises heating (burners) and steam production (boilers), the same conversion efficiency is assumed for fossil fuel-based burners/boilers and hydrogen burners/boilers.

TABLE 1. SHARE OF ≥400°C HEAT DEMAND IN FOSSIL FUEL CONSUMPTION BY INDUSTRY

Iron and steel	98%
Chemical and petrochemical	33%
Non-ferrousmetals	98%
Non-metallicminerals	92%
Transport equipment	44%
Machinery	44%
Food and tobacco	12%
Paper,pulp and printing	58%
Wood and wood products	58%
Textile and leather	5%
Industry not elsewhere specified	44%

Source: MRI (2018)

(2) Transport sector

i. Based on IEA (2022b), final energy demand in 2019 is identified for each ASEAN country by mode of transportation.
ii. For road transport, it is assumed that light-duty vehicles run on gasoline and LPG and will be converted to battery electrical vehicles (BEVs). Therefore, they are excluded from the current study. Heavy-duty vehicles are assumed to run on diesel. Heavy-duty trucks and buses that are fueled with diesel today are likely to be replaced by fuel-cell electric vehicles (FCEVs) from the perspectives of travel distance and carrying capacity.
iii. Likewise, all fuels used in air, maritime, and rail transport represent potential hydrogen demand. However, it should be noted that synthesized fuels (e-fuel) produced from hydrogen may be chosen for these modes of transportation.
iv. The fuel efficiency of fuel cell trucks and buses vary depending on the vehicle type and capacity and can thus be larger or smaller than that of diesel vehicles. Hence, the same fuel efficiency is assumed for FCEVs and diesel vehicles. The same assumptions are applied for air, maritime, and rail transport[4].

Based on the abovementioned methodology, potential hydrogen demand in the industry and transport sectors in 2019 are estimated. Potential hydrogen demand in 2050 is estimated by multiplying the potential hydrogen demand in 2019 by the ratio of final energy consumption in the industry and transport sectors in the ASEAN region in 2050 to that in 2019 as forecasted in ERIA (2021). Assuming that hydrogen will be introduced after low-carbon technologies commercialized today have been deployed, estimations are based on the Alternative Policy Scenario (APS) which projects advancements in low-carbon technology deployment, instead of business-as-usual (BAU).

2.2.2. Potential hydrogen supply

Given that increasing renewable power generation should be prioritized in the ASEAN region, potential hydrogen supply was evaluated under the assumption that renewable power generation would primarily be used to replace fossil fuel-fired thermal power generation, after which the remaining

4 The fuel efficiency of conventional diesel-powered buses and trucks is 3.6~9.1 MJ/km and 3,.6~19 MJ/km (estimated by author based on data from Ministry of Land, Infrastructure, Transport and Tourism, Japan; https://www.mlit.go.jp/jidosha/jidosha_fr10_000044.html), respectively, and that of FCEVs is 9 MJ/km (converted from 7.5kg-H2/100km (Hydrogen LHV: 120MJ/kg); Data source: Hydrogen Europe, "Green Hydrogen Investment and Support", P.26, https://profadvanwijk.com/wp-content/uploads/2020/05/Hydrogen-Europe_Green-Hydrogen-Recovery-Report_final.pdf). A more detailed evaluation would require consideration of the different efficiency levels of each vehicle type.

renewable power could be used to produce hydrogen. The methodology provided below was followed for the evaluation:

i. Renewable energy potential (potential installed capacity)[5] is estimated from existing studies (ERIA, 2021; IRENA & ACE, 2022).
ii. The capacity factor of renewable power generation in each ASEAN country is derived from IRENA Data & Statistics to calculate renewable energy potential (potential power output).
iii. Potential hydrogen supply is estimated based on the assumption that the renewable power remaining after deduction of the 1) total power generation in 2050 and 2) additional power generation needed to account for the electrification of certain final fossil fuel consumption in 2050 and beyond (in other words, final fossil fuel consumption less what can be replaced with hydrogen, or the potential hydrogen demand in the industry and transport sector estimated above) from renewable energy potential (TWh). Final energy consumption in 2050 is derived from APS projections in ERIA (2021). Fossil fuel-fired thermal power generation abated using carbon capture and storage (CCS) is likely to account for a part of total power generation; and therefore, the assumption that all power generation will be covered by renewable energy results in a conservative estimate of potential hydrogen supply. The electric power required to replace fossil fuel consumption is calculated using given conversion efficiency factors[6]. Producing hydrogen with electrolysis requires 4.5 kWh/Nm^3-H_2=50.4 kWh/kg-H_2.
iv. It should be noted that hourly renewable energy output variability has not been considered when estimating the surplus power available.

5 Here, "potential" refers to the technical potential of renewable energy, which applies technology characteristics and land eligibility constraints to their theoretical potential. Economic considerations have not been made. Details of the constraints considered vary among different studies.

6 In the industry and residential sectors, the efficiency of fossil fuel-based equipment and electrical appliances are assumed to be 80% and 90%, respectively. In the transport sector, the efficiency of conventional vehicles and electric drive vehicles are assumed to be 0.5 km/MJ and 2.8 km/MJ, respectively.

CHAPTER 3. MAJOR FINDINGS

3.1. REVIEW OF CLIMATE AND HYDROGEN POLICIES IN ASEAN MEMBER COUNTRIES

3.1.1. A REVIEW OF CLIMATE POLICIES

Most countries in the ASEAN region have announced their ambitions to achieve carbon neutrality in around 2050 yet face many challenges in achieving this goal. Carbon neutrality goals are supported by nationally determined contributions (NDCs), many of which have been updated over the past two years. Indonesia, the Philippines, Thailand, and Vietnam have included more ambitious conditional targets that can be achieved by sufficient support from developed countries.

Besides Singapore and Brunei Darussalam, which do not have coal-fired power plants in their electric power systems, Vietnam has pledged to phase out coal by the 2040s. Cambodia, Indonesia, and the Philippines have also announced that they will not invest in new coal-fired power plant projects. These countries plan to increase uptake of natural gas and introduce renewable energy in the long run. (Appendix 1 provides a table of carbon neutrality goals, greenhouse gas reduction targets, and coal phase-out policies in the ASEAN region.)

3.1.2. RENEWABLE ENERGY TARGETS

Figure 1 presents the shares of different energy sources in the primary energy mix in each ASEAN member country. All countries except for Myanmar rely heavily on fossil fuels. Biomass dominates the renewable energy portion of the energy mix in all countries. Indonesia and the Philippines also rely on geothermal energy (8% and 16% of the primary energy mix, respectively). Solar power and wind power currently account for less than 1% in all countries.

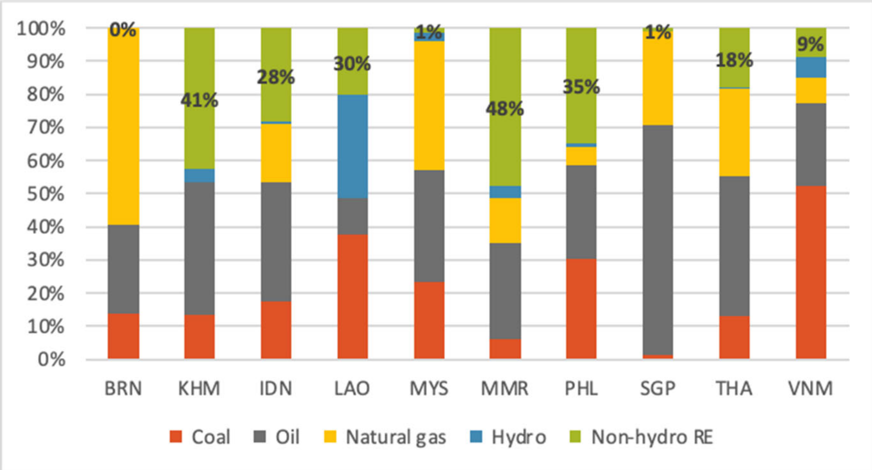

FIGURE 1. PRIMARY ENERGY MIX IN ASEAN MEMBER COUNTRIES (2020)

Source: compiled by authors based on IEA (2022b)

Note:

1) The country codes used are as follows: Brunei Darussalam (BRN), Cambodia (KHM), Indonesia (IDN), Lao DPR (LAO), Malaysia (MYS), Myanmar (MMR), the Philippines (PHL), Singapore (SGP), Thailand (THA), and Vietnam (VNM)
2) The labeled percentages represent the share of non-hydro renewable energy in the primary energy mix.

All ASEAN member countries have set up targets for increased renewable energy deployment (Appendix 2 provides details on renewable energy targets for each country). Countries that have recently updated their energy policy have adopted more ambitious targets. Most countries will rely greatly on massive deployment of solar PV to meet their targets. Indonesia, the Philippines, and Vietnam seek also to introduce offshore wind power in the longer term.

3.1.3. Hydrogen policies and roadmaps

Hydrogen has been mentioned in many national energy development plans as a promising emerging technology that will support decarbonization. Yet, only Singapore has set out a hydrogen strategy. Some countries are in the process of formulating hydrogen strategies or roadmaps. Other countries have announced studies and pilot projects at the corporate level. Indonesia's National Energy Plan (RUEN) includes a general action plan for hydrogen development and Malaysia's National Energy Policy 2022-2040 includes initiatives to formulate a hydrogen roadmap, a national strategy, and relevant regulations. It also aims to establish an internationally competitive hydrogen energy hub in Sarawak in the long term (2031-2040). Brunei has concluded Memoranda of Understanding (MOUs) with Asian countries such as Japan and Singapore on cooperation on building a hydrogen supply chain. (Appendix 3 provides for more details on hydrogen-related policies by country.)

3.2. The role of hydrogen in decarbonizing hard-to-abate industries and transport in ASEAN countries

Because of its potential as a feedstock, energy carrier and storage medium, green hydrogen promises to be key to decarbonizing many sectors of the economy. As a fuel, hydrogen can be used in: a) fuel cell vehicles in the transport sector, b) power generation (starting with co-combustion of hydrogen with gas or ammonia with coal and gradually shifting to 100% hydrogen), and c) in boilers and furnaces in the industrial sector.

As aforementioned, this study focuses on the potential of using hydrogen in decarbonizing hard-to-abate industrial processes and transport, which promise to have an economy-wide impact. Hydrogen use in the electric power sector is not considered as the study assumes that renewable energy will primarily be used for power generation. It should also be noted that replacing conventional grey hydrogen applications have not been considered.

3.2.1. Industries

Potential hydrogen demand in the industry sector is exhibited by country in Figure 2. Despite improvements in energy efficiency, energy consumption in the industry sector will increase significantly in 2050 driven by economic growth. By country, potential hydrogen demand is largest in Indonesia (62 Mtoe), followed by Vietnam (39 Mtoe), Thailand (22 Mtoe), and Malaysia (12 Mtoe). The potential hydrogen demand of the entire ASEAN region is 152 Mtoe, equivalent to 40% of total final energy consumption across the industry sector.

By industry, the cement industry, followed by the iron and steel industry, has the largest potential in hydrogen supply. In the iron and steel industry, potential hydrogen demand can include not only high-temperature heat demand, but also hydrogen use in direct reduction iron (DRI) processes resulting from conversion from conventional coke-fired blast furnaces. However, while blast furnaces may be introduced in the future, the ASEAN region currently relies mainly on electric arc furnaces; and therefore, this study does not consider the use of hydrogen as a reductant substitute. Potential hydrogen demand in the cement and iron and steel sectors is largest in Indonesia, Vietnam, and Thailand.

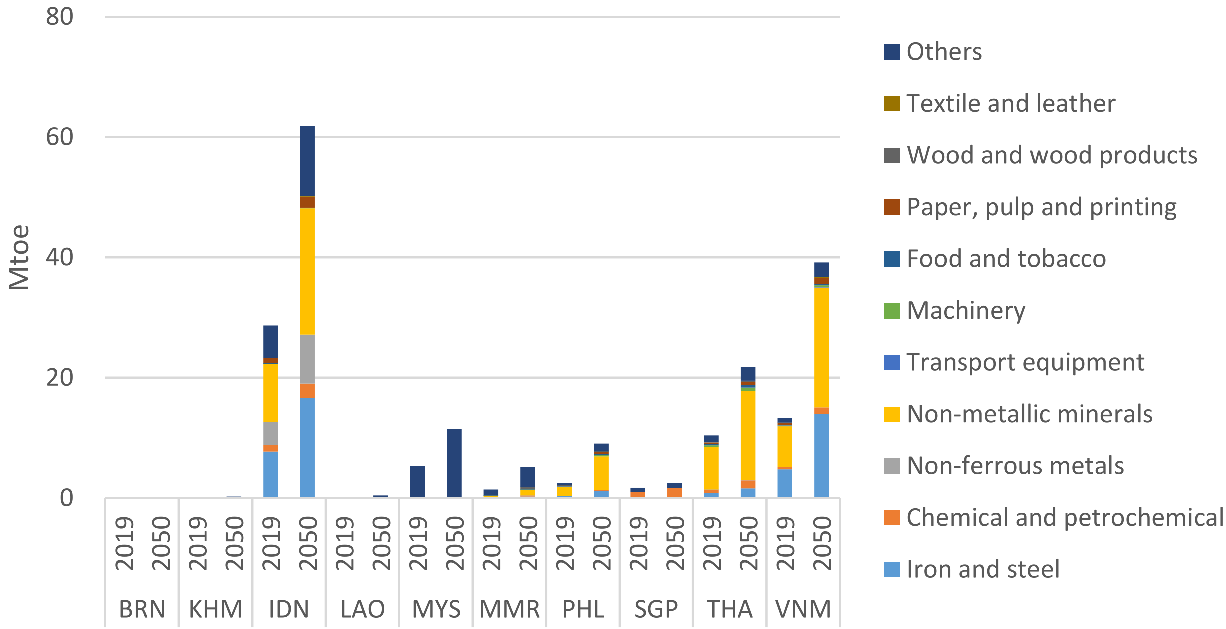

FIGURE 2. POTENTIAL INDUSTRY HYDROGEN DEMAND (2019 AND 2050)

Note:

The country codes used are as follows: Brunei Darussalam (BRN); Cambodia (KHM), Indonesia (IDN); Lao DPR (LAO); Malaysia (MYS); Myanmar (MMR); the Philippines (PHL), Singapore (SGP); Thailand (THA); and Vietnam (VNM)

3.2.2. Transport

Potential hydrogen demand in the transport sector is presented by country in Figure 3. Hydrogen demand will increase in 2050 with increased energy consumption in the transport sector driven by economic growth. Given its large population, Indonesia is home to the largest potential hydrogen demand, which will be 73 Mtoe in 2050. This is followed by Vietnam (29 Mtoe), Malaysia (21 Mtoe), the Philippines (19 Mtoe), and Thailand (12 Mtoe). The potential hydrogen demand in the transport sector across the entire ASEAN region is 166 Mtoe, accounting for 44% of final energy consumption in the sector. By mode of transportation, road transport (vehicles) accounts for approximately 80% of the total potential hydrogen supply.

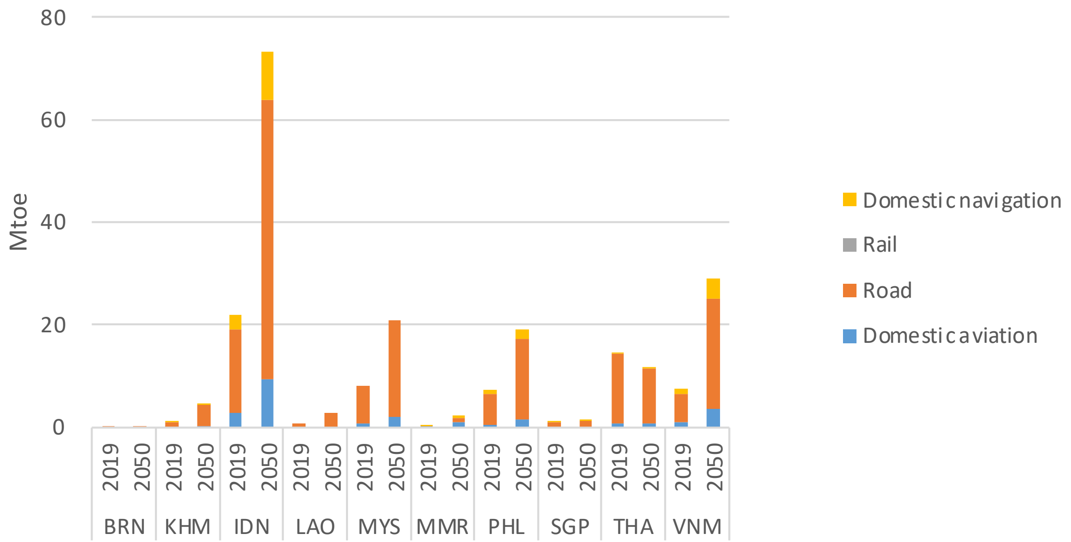

FIGURE 3. POTENTIAL TRANSPORT HYDROGEN DEMAND (2019 AND 2050)

Note:

The country codes used are as follows: Brunei Darussalam (BRN), Cambodia (KHM), Indonesia (IDN), Lao DPR (LAO); Malaysia (MYS), Myanmar (MMR), Singapore (SGP), the Philippines (PHL), Thailand (THA), and Vietnam (VNM).

3.3. Potential hydrogen supply

Figure 4 compares renewable energy potential with total power generation in 2050. RE P1 represents renewable energy potential as analyzed in ERIA (2022), and RE P2 is based on IRENA & ACE (2022). Both analyses include solar PV, onshore wind power, offshore wind power, biomass, hydropower, and geothermal power. Even under the assumption that renewable energy will cover both total power generation in 2050 as projected in ERIA (2021) and the additional power generation needed to accommodate increased electrification demand driven by further electrification in 2050 and beyond, the renewable energy potential in most ASEAN countries exceeds total power generation. Therefore, surplus renewable energy is available for use in hydrogen production.

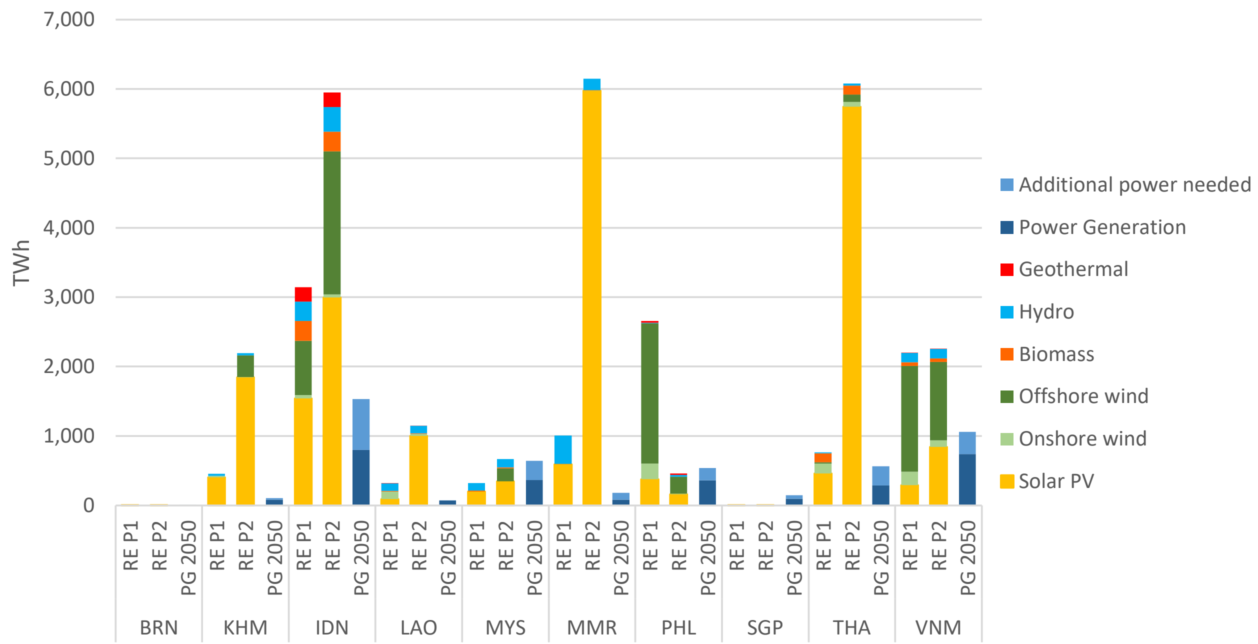

FIGURE 4. RENEWABLE ENERGY POTENTIAL FOR HYDROGEN PRODUCTION

Notes:

1) The country codes used are as follows: Brunei Darussalam (BRN); Cambodia (KHM), Indonesia (IDN); Lao DPR (LAO); Malaysia (MYS); Myanmar (MMR); Singapore (SGP); Thailand (THA); and Vietnam (VNM)

2) "Power generation" represents power generation in 2050, based on APS in ERIA (2021). "Additional power needed" represents the power generation needed to accommodate the increased demand driven by further electrification in 2050 and beyond, calculated by the authors based on an estimation of how much remaining fossil fuel use in 2050 can be electrified.

3) Solar PV will account for a significant share of renewable energy in the ASEAN region. Since solar power is available only during the day, this suggests a low capacity factor for electrolyzers, and thus high hydrogen production costs. However, if electrolyzer costs become sufficiently low, then this should not be a critical issue.

Across the entire ASEAN region, total power generation is projected to be 2,900 TWh in 2050 (ERIA, 2021). Additional electric power generation to accommodate electrification demand in 2050 and beyond will amount to 2,000TWh, calculated by the authors based on an estimation of how much remaining fossil fuel use in 2050 can be electrified. Together total electric power demand will be 4,900 TWh. Given that ASEAN-wide renewable energy potential ranges between 11,000 (RE P1) ~ 25,000 (RE P2) TWh, 6,000 ~ 20,000 TWh of renewable energy can be used for hydrogen production.

The potential for hydrogen production is especially large in Cambodia, Indonesia, Laos PDR, Myanmar, Thailand, and Vietnam.

CHAPTER 4. CONCLUSIONS

4.1. MEETING REGIONAL DEMAND

Based on the potential hydrogen supply (optimistic case) and demand concluded in Chapter 3, the authors analyzed whether potential hydrogen supply would suffice potential demand in 2050 (Figure 5). In all countries except Malaysia, as well as Brunei Darussalam and Singapore where both supply and demand will be limited, potential supply exceeded demand. Myanmar and Thailand marked an outstanding amount of potential surplus supply. In total, the ASEAN region bears the potential to supply three times the potential hydrogen demand in 2050.

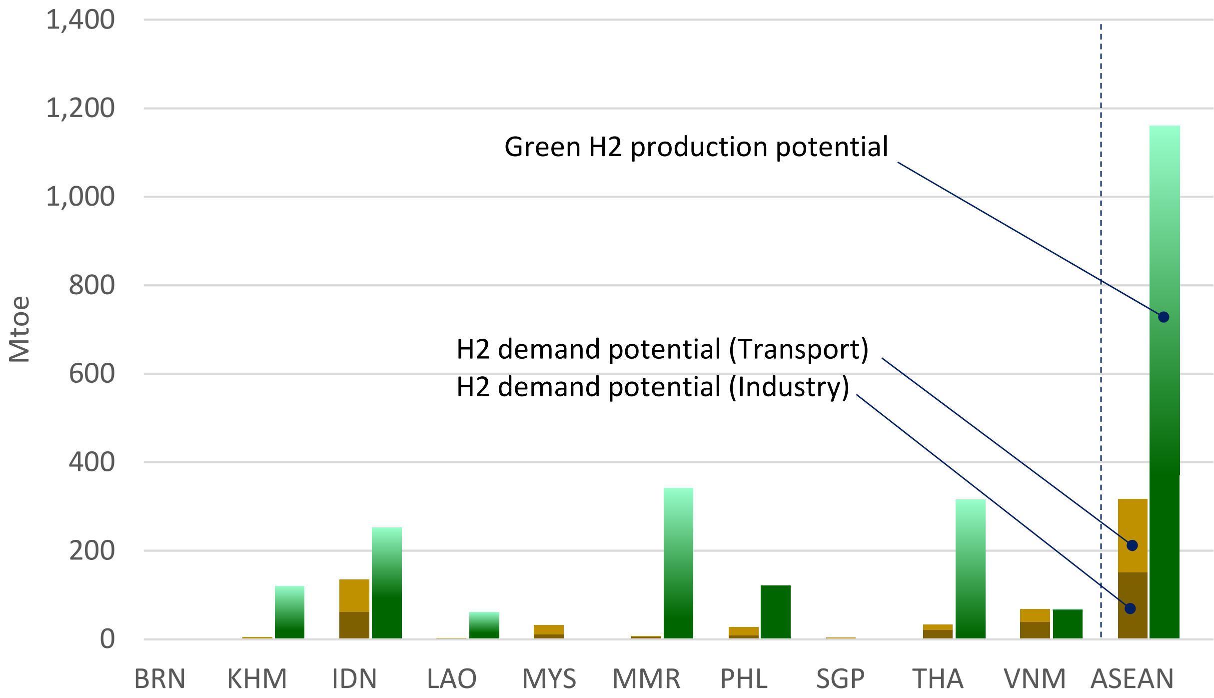

FIGURE 5. COMPARISON OF POTENTIAL GREEN HYDROGEN SUPPLY & DEMAND (2050)

Note:

The country codes used are as follows: Brunei Darussalam (BRN), Cambodia (KHM), Indonesia (IDN), Lao DPR (LAO), Malaysia (MYS), Myanmar (MMR), the Philippines (PHL), Singapore (SGP), Thailand (THA), and Vietnam (VNM)

Since there are many different approaches to defining renewable energy potential, depending on which constraints to developing their full physical potential are considered, the sufficiency of potential green hydrogen supply to meet regional demand in 2050 was analyzed for a range of cases. Figure

6 presents the amount of surplus hydrogen supply ranging from the most pessimistic to the most optimistic potential supply studied.

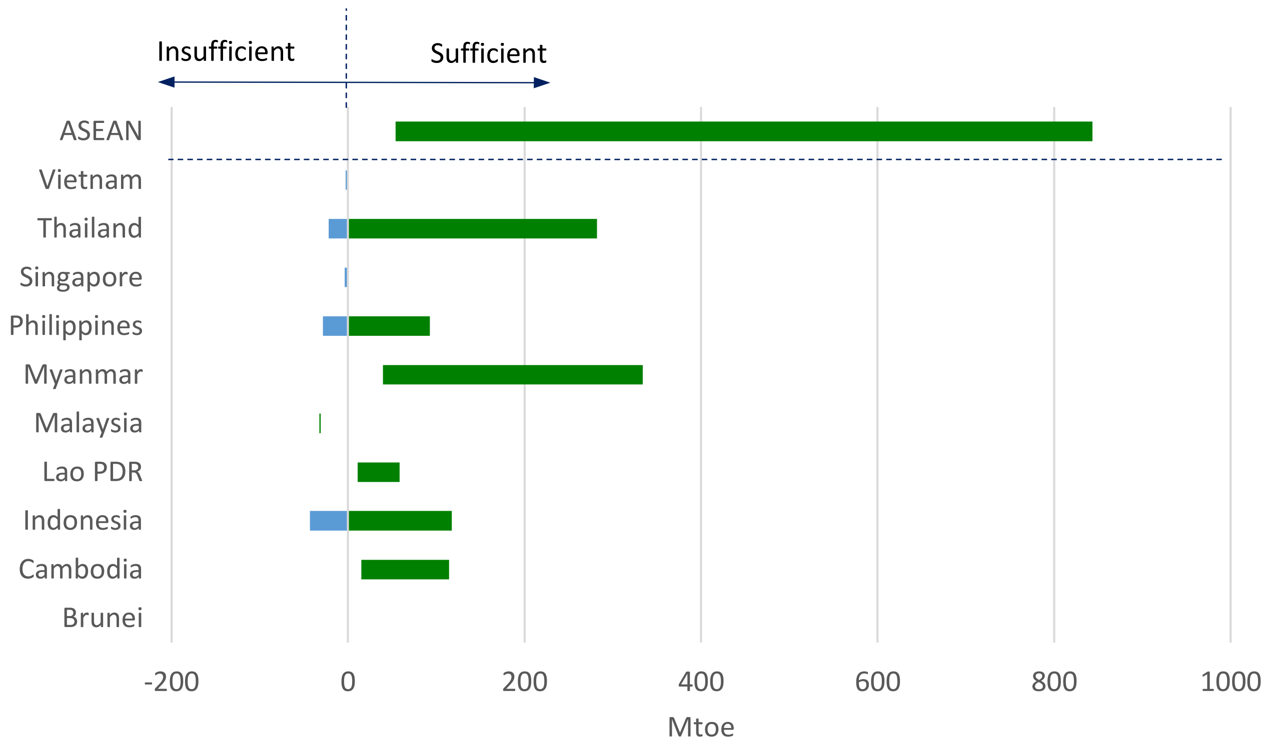

FIGURE 6. SUFFICIENCY OF POTENTIAL GREEN HYDROGEN SUPPLY (2050)

Note:

The country codes used are as follows: Brunei Darussalam (BRN); Cambodia (KHM), Indonesia (IDN); Lao DPR (LAO); Malaysia (MYS); Myanmar (MMR); Singapore (SGP); Thailand (THA); and Vietnam (VNM)

Myanmar, Lao PDR, and Cambodia will have sufficient hydrogen supply to cover domestic demand. Other than Brunei Darussalam, Malaysia, Singapore, and Vietnam, where demand will exceed supply in all cases, Thailand, the Philippines, and Indonesia may have a shortage of domestic supply when the physical potential is not fully harnessed.

The entire ASEAN region will have a surplus supply of green hydrogen, ranging from 54~843 Mtoe[7]. Therefore, even in the most pessimistic case (54 Mtoe surplus green hydrogen), there is an ample potential supply of green hydrogen across the entire ASEAN region to cover regional hydrogen

[7] It should be noted that this study does not consider economic growth beyond 2050. When energy consumption increases with economic growth, the amount of surplus renewable energy available for hydrogen production will decrease.

demand. Therefore, the intra-regional trade of green hydrogen could offer a solution to the region-wide decarbonization of hard-to-abate industries using local resources.

Green hydrogen production may change the geopolitics of the ASEAN region to some extent. Low-income economies, such as Myanmar, Lao PDR, and Cambodia, will have the opportunity to become the region's energy supplier. However, as seen in Chapter 2, most ASEAN countries have yet to develop national hydrogen strategies, or even include hydrogen in their national energy plans. Furthermore, there are various challenges to developing the full renewable energy potential of the region. These include the lack of financial support and channels, lack of experience and regulatory frameworks, insufficient coordination among government agencies, and limited infrastructure, such as grid enhancement needs for massive renewable integration. The power development plans and renewable power targets laid out by each country also fall substantially short of their renewable energy potential (Table 2). Therefore, policy measures will need to be in place to harness their full potential.

TABLE 2. COMPARISON OF RENEWABLE TARGETS AND POTENTIAL (GW)

	Renewable power target	Potential (RE P1)
IDN	552 GW (2060) (proposed National Grand Energy Strategy)	1,884 GW
MYS	18 GW (2035) (MyRER)	225 GW
PHL	61 GW (2040) (NREP 2020-2040)	963 GW
THA	19 GW (2037) (AEDP 2018)	378 GW

Source: compiled by authors based on various sources, as indicated

Notes:

1) The country codes used are as follows: Indonesia (IDN), Malaysia (MYS), Philippines (PHL), and Thailand (THA)

2) Renewable power capacity targets are compared with renewable energy potential of countries with large potential in the most pessimistic scenario. Renewable power target for Indonesia is based on the proposed National Grand Energy Strategy[8]; for Malaysia, the Malaysia Renewable Energy Roadmap; for the Philippines, National Renewable Energy Plan 2020-2040; and for Thailand, the Alternative Energy

[8] MEMR (February 4, 2022, press release) "Indonesia to Introduce Grand Energy Strategy during G20 2022" https://www.esdm.go.id/en/media-center/news-archives/pemerintah-kenalkan-gsen-pada-presidensi-g20-indonesia

Development Plan 2018. Vietnam has not been included as PDP8 has yet to be released as of January 31, 2023.

4.2. Exporting green hydrogen outside the ASEAN region

In the entire ASEAN region, there will be 54~843 Mtoe of green hydrogen, which is equivalent to around 10～300 Mt-H2. This implies that the region is a potential green hydrogen exporter.

Japan aims to introduce 3 million tonnes of hydrogen in 2030 and 20 million tonnes in 2050.The ASEAN region bears the potential to become a major supplier of green hydrogen for Japan. The proximity of the region to Japan will be an advantage. Furthermore, green hydrogen imports from the ASEAN region will contribute to diversifying its energy imports, and thus serve Japan’s energy security.

Another consideration to be made is Singapore’s global importance as a bunkering hub. Singapore is one of the world’s largest bunkering hubs, supplying almost 50 million tonnes of marine bunker fuel to vessels in 2021[9]. Amid increasing calls for low-carbon vessel fuels led by the International Maritime Organization (IMO)[10], green hydrogen will play an important role in decarbonizing marine fuels. The Maritime and Port Authority of Singapore seeks to offer various low and zero-carbon fuel solutions to support the bunkering needs of the global shipping industry (MPA, 2022). The MPA expects hydrogen and its carriers (including ammonia and e-methanol) as well as bio-LNG to potentially play important roles in the decarbonization of international shipping in the medium to long term. If the surplus supply of green hydrogen (around 50～850 Mtoe) were to be converted to e-fuel, the region would be able to supply around 40～600 Mtoe[11] of e-fuel. Hence, while in the most pessimistic case, the region will not be able to produce enough e-fuel to fully cover Singapore’s bunker sales, a reasonable amount of regionally produced e-fuel can be collected in Singapore from across the ASEAN region. This can potentially offer large business opportunities for the ASEAN region.

9 Maritime and Port Authority of Singapore (n.d) Bunkering Statistics https://www.mpa.gov.sg/port-marine-ops/marine-services/bunkering/bunkering-statistics

10 The IMO aims to reduce carbon intensity (emissions per transport work) by at least 40% by 2030, pursuing efforts towards 70% by 2050.

11 A conversion efficiency of 70% is assumed.

Chapter 5. Recommendations

5.1. Building an intra-regional green hydrogen supply chain

The ASEAN region possesses significant renewable energy potential substantially exceeding the projected power generation in 2050. By harnessing this surplus renewable energy to produce hydrogen, hard-to-abate industries and transport in the region can be decarbonized.

However, while some ASEAN member countries have sufficient potential to cover domestic demand, other countries will see a shortage in hydrogen supply. In addition, areas with high hydrogen demand are not always located close to potential production hubs; and therefore, new international supply chains and networks will need to be built. By establishing an intra-regional supply chain and distribution network, all ASEAN countries will gain access to green hydrogen.

Green hydrogen produced in the ASEAN region may not always be the cost-competitive option compared to hydrogen produced in other regions of the world. However, while studies including IEEJ (2021) have pointed out that the distance from the origin of the hydrogen to its destination does not greatly affect the cost of hydrogen, limiting hydrogen imports from outside the ASEAN region will contribute to enhancing regional energy security. Regional production will also enable hydrogen-driven economic growth.

Yet, building an intra-regional green hydrogen supply chain will entail many challenges. First, considerations will need to be made at the regional level regarding the preferred hydrogen carrier and mode of distribution. Many studies are currently being conducted globally on different hydrogen carriers, including liquid hydrogen, methylcyclohexane (MCH), ammonia, and e-methane. The advantages and disadvantages of each carrier will need to be carefully considered in light of various factors, including cost, infrastructure availability, and end-use applications.

Another important consideration would be whether it would be more cost-effective to produce hydrogen close to the renewable energy source for shipping via pipeline, lorry or vessel, or to transmit renewable power through international transmission lines for hydrogen production at a so-called hydrogen hub, ideally close to a port. IRENA (2020a) suggests that suitable transmission lines are rare and costly; and therefore, hydrogen carriers could enable the trade of hydrogen as molecules or commodities. This would also contribute to developing the green hydrogen market in the ASEAN region.

It is important that these decisions are made in consensus across the region so that the infrastructure, including shipping and receiving ports, as well as storage facilities, match the preferred hydrogen carrier. Existing local laws and regulations or the absence of such instruments may become barriers to the development of infrastructure or even the handling of hydrogen and its derivatives, as they are currently mainly used in the refining, fertilizer, and petrochemical industries. As the green hydrogen market develops, a regional certification scheme for hydrogen that is consistent across borders will be essential in ensuring that there are no mismatches between the exporter and importer.

Many Japanese companies are frontrunners in exploring the development of a commercial hydrogen supply chain with different carriers. Having succeeded in the international sea shipping of hydrogen to Japan[12], they are currently scaling up their technologies. With more than eighty years' experience in handling hydrogen, Japan is home to an established domestic liquid hydrogen distribution network. Japan's experience with relevant infrastructure, transportation and storage technologies, laws and regulation, and safety standards can help develop ASEAN's regional hydrogen market.

5.2. Further promoting renewable energy deployment

For green hydrogen to be a realistic and optimal solution for decarbonizing the economy, the renewable power used in its production should be available in surplus to that needed for more efficient uses. Renewable power should primarily be fully harnessed to decarbonize sectors whose carbon footprint can be lowered by using it directly. Therefore, investment should first be targeted at developing renewable energy to secure the surplus resources that will be needed to produce green hydrogen.

To support this, it is essential that polices are put in place for the massive deployment of renewable energy in each country. This will help lower renewable power generation costs, which remain and in turn bring down green hydrogen production costs, which is most affected by power generation costs (IEEJ, 2021).

One of the factors that has hindered the development of renewable energy in the ASEAN region is fossil fuel subsidies. Many ASEAN countries have provided subsidies to make fossil fuels affordable for the general public[13]. By lowering the cost of fossil fuels relative to renewable sources, such

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[12] The CO2-free Hydrogen Energy Supply-chainTechnology Research Association (HySTRA, https://www.hystra.or.jp/en/) successfully demonstrated that hydrogen can be produced using Latrobe Valley coal and a mix of biomass and transported to Japan as liquefied hydrogen. In 2020, the Advanced Hydrogen Energy Chain Association for Technology Development (AHEAD) completed an international hydrogen supply chain demonstration, bringing hydrogen from Brunei to Japan using the Organic Chemical Hydride method, which involves fixing hydrogen to toluene to convert it to methylcyclohexane (MCH) as a Liquid Organic Hydrogen Carrier (LOHC).

[13] In 2021, Brunei, Indonesia, Malaysia, Thailand, and Vietnam had fossil fuel subsidies in place. The total subsidy as share of GDP was 1.5%, 2.7%, 1.0%, 0.6%, and 2.3%, respectively. Indonesia, Malaysia, and Thailand have abolished transport oil subsidies in their fossil fuel subsidy reforms. (IEA, 2022a)

subsidies can create an artificial cost advantage (Bridles & Lucy, 2014). The public funds allocated to fossil fuels should be invested in renewable energy. Later when green hydrogen is deployed, policies can be put in place to incentivize the use of vehicles powered by green hydrogen-derived fuels.

Another challenge is the need to upgrade the power grid in ASEAN countries to enable the integration of increased amounts of variable renewable energy, such as solar PV and wind power.

Despite ongoing discussions about co-firing ammonia in existing coal-fired power plants, the authors did not consider this technology in the current analysis. This is because the process of producing hydrogen by electrolysis and converting it to ammonia for use in coal-fired thermal power plants will reduce the total energy efficiency to 20%.

It should be noted that the authors have not conducted an economic analysis of producing green hydrogen in the ASEAN region. In 2050, the levelized cost of hydrogen in the region will not be as competitive as that of other regions and countries (IRENA, 2022b)[14]. Therefore, importing green hydrogen from outside the region may prove to be more cost-effective. However, regional production of hydrogen for regional use of hydrogen will serve its energy security. Japan can play an important role in building and expanding the regional hydrogen market and thus bringing costs down through cooperation with ASEAN countries on hydrogen-related technology development.

5.3. Japan's role in promoting green hydrogen development in the ASEAN region

Both the public and private sectors in Japan can contribute greatly to the development of renewable energy in the ASEAN region. Since the renewable energy market is yet to be fully developed in some countries, players may be able to enjoy first-mover advantage in establishing the business environment for renewable energy, and in turn for hydrogen. Overseas hydrogen-related technology development led by Japan to date have tended to focus on hydrogen carriers and other downstream components of the international hydrogen supply chain. Increased investment and government support in the earlier phases of the supply chain will not only help accelerate the decarbonization of the electric power sector in the ASEAN region but also give Japanese actors increased access to renewable power for green hydrogen production. The proximity of the ASEAN region to Japan, compared to other potential exporters is an advantage with a view to enhancing energy security.

[14] The levelized cost of hydrogen (LCOH) derived from supply-demand analysis of the ASEAN region is estimated to be USD 2.0 based on the estimated hydrogen demand for 2050. This cost level is only competitive against Ukraine, Japan, and the Republic of Korea among the regions and countries evaluated.

2023 marks the “50th Year of ASEAN-Japan Friendship and Cooperation.” Over the years, Japan has built many cooperation frameworks in place for supporting ASEAN countries’ energy transition. Under these frameworks, Japan can also support the designing of aggressive but feasible decarbonization policies with consideration of region-specific circumstances and needs. Such support could include not only technological and financial support, but also in-depth studies to reveal local challenges and solutions, support in formulating master plans based on such studies, and the implementation of stakeholder dialogue.

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Appendix 1

Climate goals in the ASEAN region

The carbon neutrality goal, greenhouse gas reduction targets, and coal phase-out policy set out by each ASEAN member economy are compiled in Table A.

TABLE A. CLIMATE GOALS IN THE ASEAN REGION

Country[1]	Carbon neutrality goal	2030 GHG reduction target (NDC)				Coal phase-out policy
		Reduction target type	Unconditional target	Conditional[2] target	Baseline year	
BRN	2050	Relative emissions	20%	-	BAU	Yes
KHM	2050	Relative emissions	41.7%	-	BAU	Yes[4]
IDN	2060	Relative emissions	29%	41%	BAU	Yes[4]
LAO	2060	Relative emissions	60%	-	Baseline	No
MYS	2050	Carbon intensity	45%	-	2005	Yes[4]
MMR	2050	Other	Avoidance of 245 $MtCO_2$	-		No
PHL	-	Relative emissions	2.71%	75%	BAU	Yes[4]
SGP	2050	Carbon intensity	36%[4]	-	2005	Yes
THA	2050[2]	Relative emissions	20%	25%	BAU	No
VNM	2050	Relative emissions	9%	27%	BAU	Yes

Source: compiled by authors based on NDCs and other sources

Notes:

1) The country codes used are as follows: Brunei Darussalam (BRN), Cambodia (KHM), Indonesia (IDN), Lao DPR (LAO), Malaysia (MYS), Myanmar (MMR), the Philippines (PHL), Singapore (SGP), Thailand (THA), and Vietnam (VNM)

2) Conditional targets are dependent on the availability of international support for finance, technology transfer and development, and/or capacity building.

3) Thailand aims to achieve carbon neutrality by 2050 and net zero carbon GHG emissions by 2065.

4) No new projects will be approved.

5) Singapore aims to peak emissions in 2030, which will lead to 36% reductions relative to 2005 in 2030.

APPENDIX 2

Renewable energy targets in the ASEAN region

Brunei Darussalam: Under Brunei Vision 2035[15], Brunei aimed to increase the deployment of renewable energy up to 10% in 2035. This target was updated in its National Climate Change Policy[16], which aims to have a 30% share of renewables, comprising mostly solar PV, by 2035.

Cambodia: The Cambodia Basic Energy Plan (BEP)[17] recommends a power generation mix of coal (35%), hydropower (55%), and other renewable energy (10%) for 2030. This was updated in its Long-Term Strategy for Carbon Neutrality[18] published in December 2021, in which it pledged to increase solar PV, hydro, biomass, and other renewables to 35% of the power generation mix by 2050. Solar PV will account for 12%.

Indonesia: Under its National Energy Policy[19] enacted in 2014**,** Indonesia seeks to source 23% of its energy mix with renewable energy by 2025 and 31% by 2050. The government has also announced that it is formulating a National Grand Energy Strategy (GSEN) that proposes to have new and renewable energy cover 100% power generation in 2060, when total power generation capacity will be 587 GW, comprising 361 GW solar PV, 83 GW hydropower, 39 GW wind power, 35 GW nuclear power, 37 GW bioenergy, 18 GW geothermal power, and 13.4 GW ocean currents power [20].

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[18] Kingdom of Cambodia (2021) *Long-Term Strategy for Carbon Neutrality* (LTS4CN), https://ncsd.moe.gov.kh/resources/document/cambodia-LTS4CN-En

[19] Government Regulation of the Republic of Indonesia Number 79 of 2014 on National Energy Policy, *Long-Term Strategy* for Carbon Neutrality (LTS4CN), https://ncsd.moe.gov.kh/resources/document/cambodia-LTS4CN-En

[20] MEMR (February 4, 2022 press release) "Indonesia to Introduce Grand Energy Strategy during G20 2022" https://www.esdm.go.id/en/media-center/news-archives/pemerintah-kenalkan-gsen-pada-presidensi-g20-indonesia

Lao PDR: Lao PDR aims to increase the share of renewable energies to 30% of total energy consumption in 2025 under the Renewable Energy Development Strategy of Lao PDR[21] published in 2011.

Malaysia: In 2021, the Ministry of Energy and Natural Resources (KeTSA) set a target to reach a 31% share of renewable energy in the national installed capacity mix by 2025[22]. In the Malaysia Renewable Energy Roadmap[23], the New Capacity Target scenario achieves the abovementioned national target and aims to reach a 40% share in 2035. This target supports Malaysia's global climate commitment to reduce its economy-wide carbon intensity (against GDP) by 45% in 2030 relative to 2005 levels.

Myanmar: The National Electrification Program (NEP)[24] envisions 100% nationwide electricity access by the year 2030. According to the U.S. International Trade Administration, the Ministry of Electricity and Energy (MOEE) drafted a renewable energy law with the goal of generating 8% of the country's electricity through renewable sources by 2021, raising its share to 12% by 2025[25]. In April 2022, the Ministry of Information (MOI) and the Ministry of Investment and Foreign Economic Relations (MIFER) of Myanmar issued a joint press release stating that the government is planning to accelerate development of renewable energy development while seeking to increase foreign investment[26].

Philippines: The Philippines' National Renewable Energy Program (NREP) 2020-2040[27] sets a target of reaching a 35% share of renewable energy in the power generation mix by 2030 and a 50% share by 2040. To meet this target, the Philippines will need to install another 102 GW renewable

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[21] Lao People's Democratic Republic (2011) *Renewable Energy Development Strategy in Lao PDR* https://data.laos.opendevelopmentmekong.net/en/dataset/renewable-energy-development-strategy-in-lao-pdr

[22] Department of Energy, Malaysia (2021). *Twelfth Malaysia Plan 2021-2025 (RMK12)*, https://rmke12.epu.gov.my/en

[23] Sustainable Energy Development Authority, Malaysia (2021), *Malaysia Renewable Energy Roadmap: Pathway towards Low Carbon Energy System*, https://www.seda.gov.my/reportal/wp-content/uploads/2021/12/MyRER_webVer-1.pdf

[24] World Bank (n.d.) "National Electrification Program," https://projects.worldbank.org/en/projects-operations/project-detail/P152936

[25] International Trade Administration, (July 28, 2022) "Burma – Country Commercial Guide" https://www.trade.gov/country-commercial-guides/burma-energy

[26] Bloomberg (April 22, 2022) "Myanmar Govt to Accelerate Energy Projects Amid Power Shortages", https://www.bloomberg.com/press-releases/2022-04-21/myanmar-govt-to-accelerate-energy-projects-amid-power-shortages-l29d0bp8

[27] Department of Energy, Philippines (2022). *National Renewable Energy Program 2020-2040*, https://www.doe.gov.ph/sites/default/files/pdf/renewable_energy/nrep_2020-2040_0.pdf

electricity capacity by 2040 including 27 GW solar PV, 17 GW wind power, 6GW hydropower, 2.5 GW geothermal, and 364 MW biomass.

Singapore: In February 2022, the Minister of Finance announced at Budget 2022 that Singapore will aim to achieve net zero emissions by or around mid-century by progressively raising its carbon tax from 2024[28]. In the Singapore Green Plan 2030[29] launched in February 2021, Singapore announced its ambition to increase solar energy deployment by five-fold to at least 2 GWp, which would cover around 3% of projected electricity demand in 2030.

Thailand: Thailand's Alternative Energy Development Plan 2018-2027[30] seeks to increase the proportion of renewable energy in Thailand to 30% (including imported hydropower) of total energy consumption by 2037.

Vietnam: In 2015, the government announced the national development strategy for renewable energy, aiming for renewable energy to account for around 32% of total primary supply and electricity generation by 2030 and 43% by 2050[31]. Targets are to be updated in the Power Development Plan VIII (PDP8), which is still under discussion.

TABLE B. RENEWABLE ENERGY TARGETS IN SELECTED ASEAN COUNTRIES

Country[1)]	Current share (2020)	Target share (Target year)	Description
BRN	0%	30% (2035)	Brunei Darussalam National Climate Policy (2020)[32]
KHM	28%	35% (2050)	Long-term Strategy for Carbon Neutrality (2021)[33]
IDN	26%	31% (2050)	National Energy Policy (2014)[34]
MYS	16%	40%	Malaysia Renewable Energy Roadmap (MyRER, 2021)[35]

[28] National Climate Change Secretariat, (February 18, 2022) "Singapore Will Raise Climate Ambition to Achieve Net Zero Emissions by or Around Mid Century, and Revises Carbon Tax Levels from 2024" https://www.nccs.gov.sg/media/press-release/singapore-will-raise-climate-ambition/

[29] "Singapore Green Plan 2030" https://www.greenplan.gov.sg

[30] Ministry of Energy, Thailand (2020). *Alternative Energy Development Plan 2018 (AEDP 2018)*, https://policy.asiapacificenergy.org/sites/default/files/Alternative%20Energy%20Development%20Plan%202018-2037%20%28AEDP%202018%29%28TH%29.pdf

[31] Decision No. 2068/QD-TTg, 2015, https://lawnet.vn/en//vb/Decision-No-2068-QD-TTg-approving-the-development-strategy-of-renewable-energy-2030-2050-2015-48915.html

[32] Brunei Climate Change Secretariat (2020). *op. cit.*

[33] Kingdom of Cambodia (2021). *op. cit.*

[34] Government Regulation of the Republic of Indonesia Number 79 of 2014 on National Energy Policy, *op. cit.*

[35] Sustainable Energy Development Authority, Malaysia (2021) *op. cit.*

		(2035)	
PHL	21%	50% (2040)	National Renewable Energy Plan (NREP 2020-2040)[36]
THA	18%	30% (2027)	Alternative Energy Development Plan (AEDP 2018-2027)[37]
VNM	35%	43% (2050)	Development Strategy of Renewable Energy of Vietnam[38]; to be updated in PDP8.

Source: IEA (2022b) and various other sources, as indicated

Notes:

1) The country codes used are as follows: Brunei Darussalam (BRN), Cambodia (KHM), Indonesia (IDN), Malaysia (MYS), Thailand (THA), and Vietnam (VNM).

Renewable shares and targets are provided for the power generation mix in each country, with the exception of Indonesia and Thailand, for which the figures represent shares against the primary energy mix and total energy consumption, respectively.

[36] Department of Energy, Philippines (2022). *op. cit.*

[37] Ministry of Energy, Thailand (2020). *op. cit.*

[38] Decision No. 2068/QD-TTg, 2015, *op.cit.*

APPENDIX 3

Hydrogen Strategies in the ASEAN region

Brunei Darussalam: Brunei has yet to develop any national strategies related to hydrogen, but it has concluded Memoranda of Understandings (MOUs) with Asian countries such as Japan and Singapore on cooperation on building a hydrogen supply chain. Backed by funding from Japan's New Energy and Industrial Technology Development Organization (NEDO), the Advanced Hydrogen Energy Chain Association for Technology Development (AHEAD)[39] successfully completed trials of the world's first international shipment of Methylcyclohexane (MCH) and stable hydrogen extraction in 2020, when it delivered MCH produced in Brunei to Japan.

Indonesia: Indonesia's National Energy Plan (RUEN) lays out its new and renewable energy development plan until 2050, including a general action plan for hydrogen development, such as the preparation of regulatory frameworks, technological and manufacturing capacity development, and incentives provision. In the GSEN, the government estimates that green hydrogen generation will be introduced in 2031, gradually increasing to approximately 52 GW by 2060. That would be a 10% contribution to the power mix[40].

In 2022, the German-Indonesian Chamber of Industry and Commerce (EKONID) launched the Hydrogen Business Desk (HBD)[41] to provide information regarding the development of hydrogen, primarily green hydrogen in Indonesia. Indonesia also signed an MOC on Japan and Indonesia's energy cooperation for the realization of realistic energy transitions that utilize technologies and options including but not limited to hydrogen and fuel ammonia[42]. This has been followed up by an announcement of Japan`s intentions to mobilize resources and funding from Japanese public institutions together with local parties to support Indonesia's energy under the Asia Zero Emission Community (AZEC) cooperation framework[43]. Many corporate level agreements have also been signed on various hydrogen-related technologies.

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[39] Advanced Hydrogen Energy Chain Association for Technology Development (AHEAD) https://www.ahead.or.jp/en/

[40] MEMR (February 4, 2022, press release) *op. cit.*

[41] "Hydrogen Business Desk" https://www.hydrogen-indonesia.id/home

[42] METI, Japan (Jan. 13, 2022) "Memorandum of Cooperation Between the Ministry of Economy, Trade and Industry of Japan and the Ministry of Energy And mineral Resources of the Republic of Indonesia on the Realization of Energy Transitions" https://www.meti.go.jp/press/2021/01/20220113003/20220113003-1.pdf

[43] Ministry of Foreign Affairs, Japan (Nov. 14, 2022) "Joint Announcement on Asia Zero Emission Community (AZEC) Concept" https://www.mofa.go.jp/files/100420486.pdf

Malaysia: The Twelfth Malaysia Plan[44] encouraged the advancement of hydrogen technologies in the transport sector and mentioned the formulation of a Comprehensive National Energy Policy under which the prospect of future growth related to energy, particularly on the potential of new energy from clean and sustainable sources including hydrogen, will be explored. The National Energy Policy 2022-2040[45] includes initiatives to formulate a hydrogen roadmap, a national strategy, and relevant regulations. It also aims to establish an internationally competitive hydrogen energy hub in Sarawak in the long term (2031-2040).

A number of projects using hydropower to produce hydrogen have been jointly announced by local companies and collaborators from Japan[46], Korea, and France. Another cooperation arrangement will conduct a feasibility study on leveraging the abundant solar resources of Malaysia to produce and sell green ammonia[47].

Singapore: Singapore launched its National Hydrogen Strategy in October 2022[48]. While it does not lay out quantitative targets, Singapore seeks to develop hydrogen as a major decarbonization pathway to support its transition towards net zero by 2050. Singapore has concluded cooperation arrangements in the hydrogen field with governments, such as Japan, Australia, New Zealand, and Chile. Several corporate-level MOUs have also been concluded to explore hydrogen supply chains to bring low-carbon hydrogen to Singapore using different hydrogen carriers[49].

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[44] Department of Energy, Malaysia (2021). *op. cit.*

[45] Economic Planning Unit, Prime Minister's Department, Malaysia, (2022) National Energy Policy 2022-2040 (NEP2022-2040), https://www.epu.gov.my/sites/default/files/2022-09/National%20Energy%20Policy_2022_2040.pdf

[46] For example, ENEOS, Sumitomo Corporation and SEDC Energy Sdn Bhd are considering establishing a CO_2-free hydrogen supply chain using renewable power generated at hydroelectric power stations in Sarawak, Malaysia to produce hydrogen and converting it into methylcyclohexane (MCH). (https://www.eneos.co.jp/english/newsrelease/2020/pdf/20201023_01.pdf)

[47] IHI (Dec. 15, 2022 press release) "IHI and Gentari sign MoU to explore Green Ammonia Production and Sales in Malaysia" https://www.ihi.co.jp/en/all_news/2022/resources_energy_environment/1198122_3488.html

[48] Ministry of Trade and Industry, Singapore (2022). *Singapore's National Hydrogen Strategy*, https://www.mti.gov.sg/Industries/Hydrogen

[49] For example, Sembcorp Industries, Chiyoda Corporation, and Mitsubishi Corporation signed an MOU in 2021 to explore a hydrogen supply chain using MCH (https://www.sembcorp.com/en/media/media-releases/energy/2021/october/sembcorp-industries-chiyoda-corporation-and-mitsubishi-corporation-sign-mou-to-explore-supply-chain-commercialisation-of-decarbonised-hydrogen-into-singapore/); Itochu, EDF, and Tuas Power signed an MOU on developing a green ammonia supply chain and exploring different applications,

Thailand: The Alternative Energy Development Plan 2015-2037 (AEDP2015)[50] included hydrogen as part of the "Alternative Fuels" category with a target goal of 10 Ktoe for transportation by 2036. However, AEDP2018 has excluded the category.

including for power generation and as a shipping fuel (https://www.itochu.co.jp/en/news/press/2022/221026.html).

[50] Ministry of Energy, Thailand (2015). *Alternative Energy Development Plan 2015 (AEDP 2015),* https://www.eppo.go.th/images/POLICY/ENG/AEDP2015ENG.pdf

Data deep dive

Has Japan lost its position as a leader in energy efficiency?

GDP intensity should be utilised while understanding its characteristics

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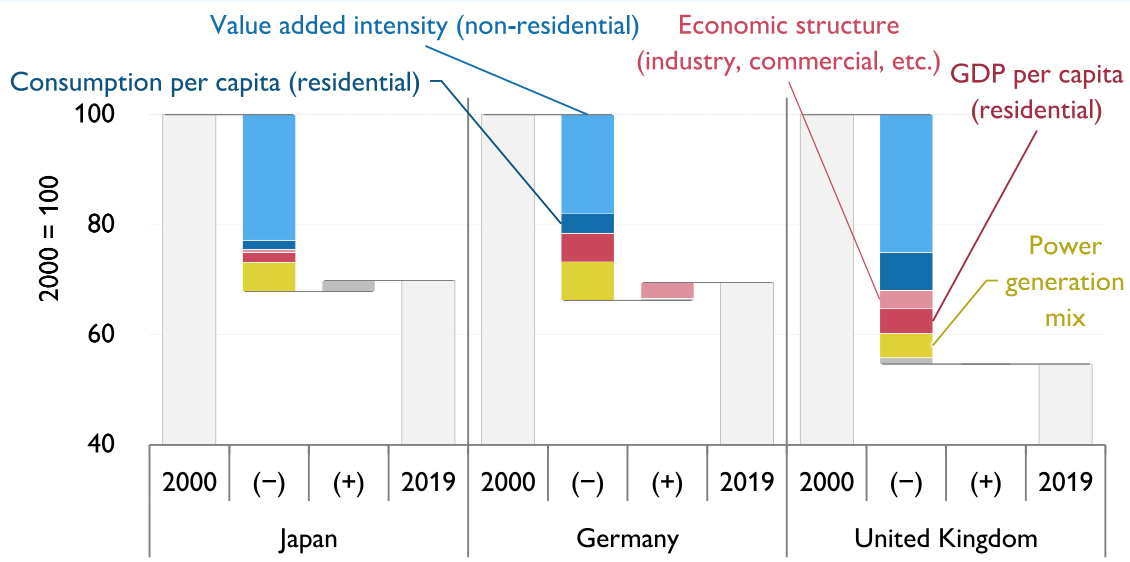
Summary

- Russia's invasion of Ukraine has raised the priority of energy security and heightened interest in energy efficiency. Under these circumstances, some consider that Japan has already lost its position as a leader in energy efficiency. When comparing energy efficiency in terms of GDP intensity – primary energy supply per unit of gross domestic product (GDP) – which is the primary macroscopic indicator of energy efficiency, Japan is falling behind the United Kingdom, Italy and Germany, and is almost on par with France among the Group of Seven (G7) countries.

- However, GDP intensity is greatly affected by the exchange rate. Even if all the constancy in substance, the gap between the United Kingdom as top runner and the other G7 countries, including Japan, will nearly halve, at most, just by switching to the next base year, which is expected to be 2020.

- Caution is also required when measuring progress in energy efficiency based on changes in GDP intensity, as it includes factors that are not inherently relevant to energy efficiency. The most significant contributor to the decrease in GDP intensity over the past two decades has been the reduction in energy consumption per unit of value added, which is a highly effective indicator of energy efficiency. However, GDP per capita, which has little relevance to actual energy efficiency, and changes in the power generation mix related to solar photovoltaics, wind and other primary electricity also made nonnegligible contributions to the decrease, with varying degrees in different countries.

Figure 1 | GDP intensity of primary energy supply and contributions to its changes



Keywords: energy efficiency, GDP intensity, exchange rate, primary electricity, decomposition analysis

An in-depth examination suggests that Japan's energy efficiency is not substantially inferior to that of Europe. However, the fact that Japan's advantage in energy efficiency is no longer immediately obvious may suggest that Japan needs to consider what else it can do as a world leader in energy efficiency, while also wholeheartedly commending Europe's progress.

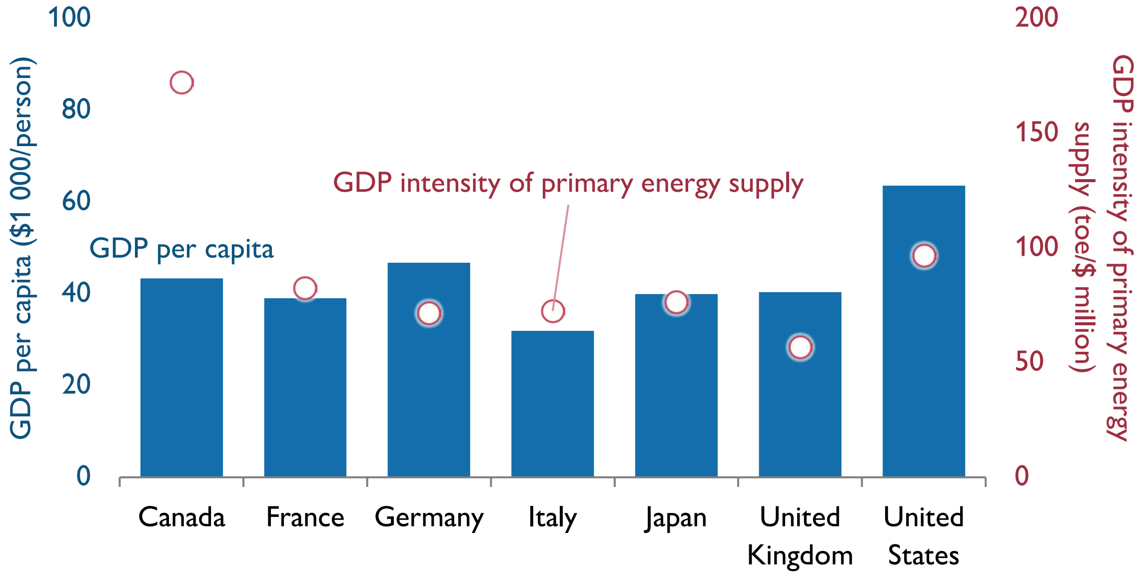
Energy efficiency in the spotlight and its macroscopic indicators

There are high expectations for low-carbon energy sources such as renewable energy and nuclear power as tools to tackle climate change issues. Perhaps because of these enormous expectations, energy efficiency has been slightly sidelined in some countries in Europe and elsewhere. However, Russia's invasion of Ukraine has raised the priority of energy security and supply stability, and attention to energy efficiency, as well as domestic energy sources, is growing. Japan has earned a reputation as a world leader in energy efficiency through its efforts since the oil crises. Energy efficiency has become the main area of Japan's international cooperation in the energy domain, and Japan's advanced energy efficiency technologies have helped maintain the country's presence. Given the recent situation, however, Japan may have already lost its lead in energy efficiency.

One widely known quantitative indicator used to assess the level of energy efficiency is energy consumption per activity (or energy service demand range). In fact, various indicators are used depending on the target and purpose. Examples of a microscopic indicator are car fuel efficiency (= energy consumption per distance travelled) and power generation efficiency (= energy consumption per amount of electricity generated). Indicators with a slightly broader scope include energy consumption per unit of crude steel production and energy efficiency of houses (energy consumption to maintain daily living). At the country level, the gross domestic product (GDP) intensity of primary energy supply is often used as a macroscopic indicator; it uses the GDP as the amount of activity and adopts the primary energy supply, which represents the country's total energy consumption, as the amount of energy consumption. This is an indicator that is both easy to understand and easy to use.

However, the GDP intensity of primary energy supply does not explicitly consider various factors that affect energy efficiency, such as economic and industrial structure, climate and geographic conditions of a country, and population distribution. Therefore, a simple comparison of countries based on this indicator is merely for convenience. In the following sections, we will analyse this energy efficiency indicator, with a focus on factors that deserve more caution in some cases. In doing so, we will examine Germany and the United Kingdom, which are frequently compared with Japan in the context of energy efficiency. A quantitative assessment of other Group of Seven (G7) countries with similar levels of economic development as Japan will also be provided.

Figure 2 | GDP per capita and GDP intensity of primary energy supply [2020]



Source: Calculated based on the IEA "World Energy Balances", the OECD "National Accounts" and the World Bank "World Development Indicators"

Energy efficiency levels are affected by exchange rates

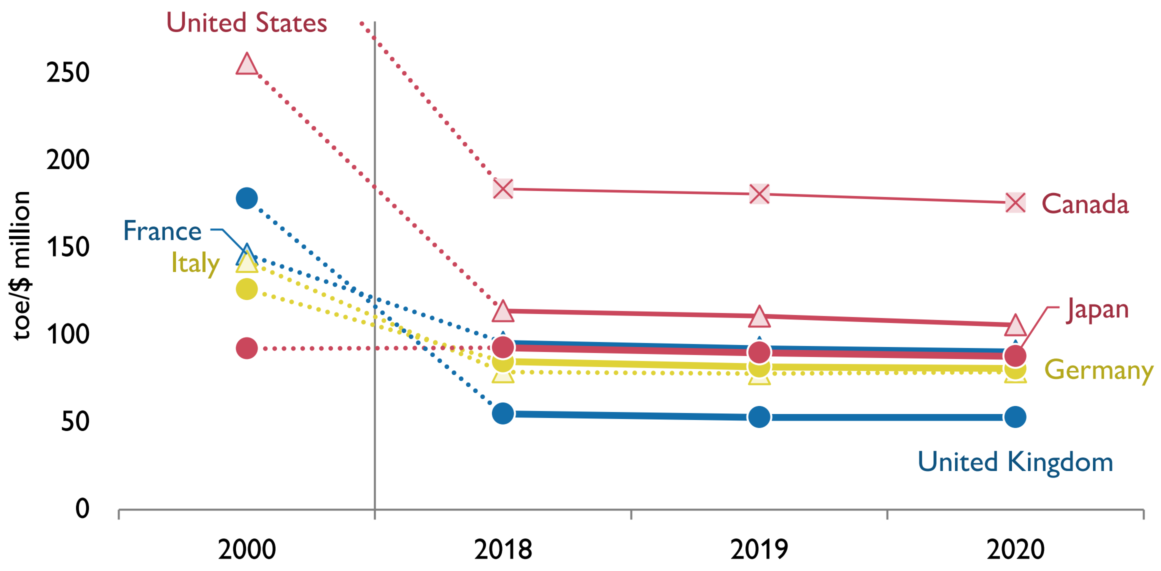
Japan has been one of the world's leaders in terms of the GDP intensity of primary energy supply. Recently, however, some say that Japan is no longer a leader in energy efficiency. For example, according to the International Energy Agency (IEA)'s statistics[1], Japan was the most energy efficient of the G7 in 2000, but in recent years it has not only fallen behind the United Kingdom, Italy and Germany, but is now almost matched by France (Figure 3).

This seems to be one of the reasons for claiming that Japan is no longer a leader in energy efficiency. However, it is important to remember that statistical data must be handled with a full understanding of its background.

When comparing the GDP intensity of primary energy supply between countries, it is necessary to decide what series to use as the denominator GDP. Often, the exchange rate used to convert that GDP into a common currency – usually the United States dollar – becomes a point of debate. For an arbitrary single year comparison, the natural solution may be to use the nominal GDP and the exchange rate for that year. For a multi-year comparison, the real GDP and exchange rate for a predetermined year are usually used. There is no set standard for which year to select for the exchange rate, but the base year for the real GDP is usually adopted. This base year for the real GDP is often a year ending in 5 or 0, such as 2015 or 2020. Therefore, exchange rates also tend to be based on a year ending in 5 or 0.

[1] "Energy Balances of OECD Countries, 1999-2000" and "World Energy Balances 2022", the first editions that carried the data for 2000 and 2020, respectively.

Figure 3 | GDP intensity of primary energy supply



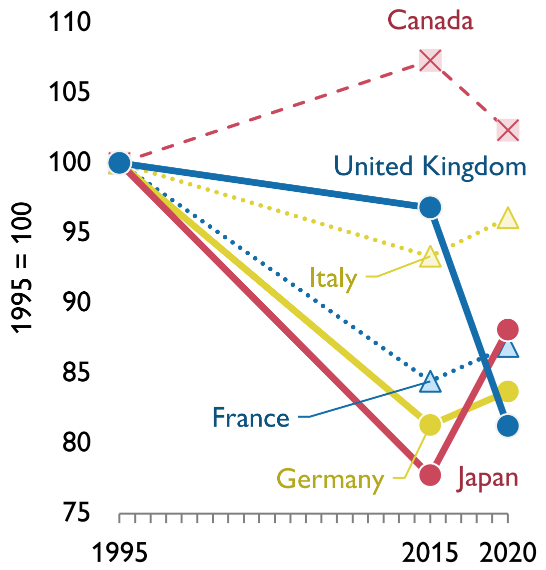
Note: The figures for 2000 are based on 1995 prices; the figures for 2018-2020 are based on 2015 prices.
Source: IEA "Energy Balances of OECD Countries, 1999-2000" and IEA "World Energy Balances 2022"

However, under the floating exchange rate system with free movement of capital and an independent monetary policy, there is no guarantee that the exchange rate for a year ending in 5 or 0 is reasonable in terms of energy economics[2]. For example, the values for the year 2000 in Figure 3 adopt the 1995 exchange rates, while the 2018-2020 values adopt the 2015 exchange rates. During that 20-year period, except for the United States with the United States dollar as its local currency, the currencies of five countries except Canada depreciated against the United States dollar (Figure 4). In other words, while exchange rates serve to enhance the energy efficiency of the five countries for the 1995-based indicator, for the 2015-based indicator, this enhancement effect is cancelled because of the switch in the base year for the exchange rates. The yen was at its highest during that time period in 1995 at ¥94/$ but was at its lowest during the time period at ¥121/$ in 2015; its fluctuation was the largest among the currencies. Therefore, among countries Japan suffered the largest deterioration (increase) of GDP intensity of primary energy supply due to the switch in the base year.

In 2020, the expected next base year for the IEA statistics, the yen and the euro appreciated against the dollar compared with 2015, while the British pound fell in value due to the negative economic impacts of Brexit at the end of January that year. Even if all the constancy in substance, the gap in the GDP intensity of primary energy supply between the United Kingdom as top runner and other countries will almost halve from the current value simply because of the change in the base year[3] (Figure 5).

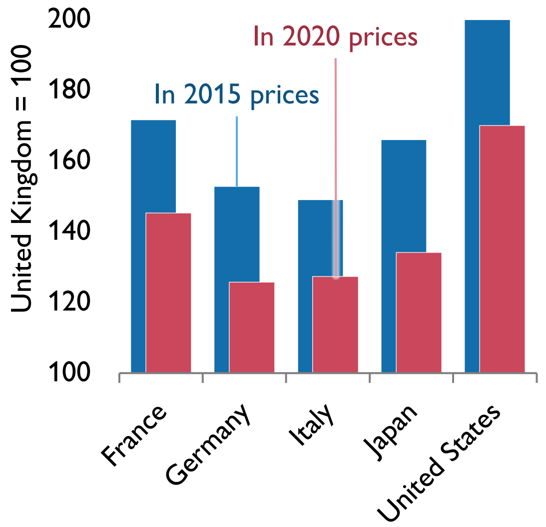
[2] This is the effect of the trilemma of international finance, in which it is impossible to fully achieve stable or fixed exchange rates as a policy target while there is free movement of capital and independence of monetary policy.
[3] When the base year changes, the GDP intensity of primary energy supply does not change at the same rate as the exchange rate because changes in the GDP deflator also come into play.

Figure 4 | Exchange rate against the United States dollar



Note: The larger the value, the stronger the country's currency.
Source: Calculated based on the OECD "National Accounts"

Figure 5 | GDP intensity of primary energy supply [2020]



Source: Calculated based on the IEA "World Energy Balances" and the OECD "National Accounts"

As the exchange rate, it is also possible to use the purchasing power parity (PPP) rate instead of the market rate. For example, Suehiro (2007) suggests using either the market rate or the PPP rate depending on the energy consumption sector[4]. However, adopting the PPP rate is not a perfect solution either and can give rise to new problems[5]. In any case, there is a risk in discussing the superiority or inferiority of energy efficiency based on the GDP intensity of primary energy supply without considering the impact of exchange rates.

Box 1 | Was it only the strong pound that made the United Kingdom the top runner?

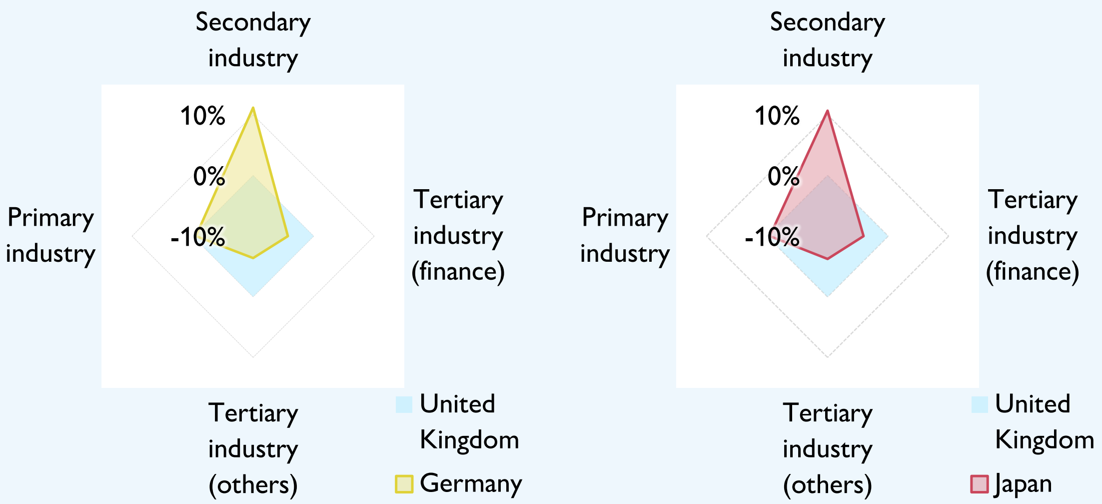
It is not only energy efficiency in the narrow sense that defines the GDP intensity of primary energy supply. As described above, the exchange rate is a major factor when making international comparisons. Climate conditions also affect the GDP intensity through the amount of energy consumption in the buildings sector.

In addition, industry, commercial, etc., and non-energy use sectors reflect the economic and industrial structure of a country. In terms of value added by industry, the United Kingdom has the largest tertiary industry in terms of share, particularly the non-energy-intensive finance sector, among the G7 countries. In contrast, for Germany and Japan, the importance of the energy-intensive secondary industry is relatively high (Figure 6). These differences manifest particularly in final energy consumption, which accounts for about 70% of the primary energy supply.

[4] SUEHIRO Shigeru, "Energy Intensity of GDP as an Index of Energy Conservation" (June 2007)

[5] These include the definitional aspect, that is, which goods are adopted in calculating the PPP rate and how accurately the quality of the goods are adjusted, and the phenomenological aspect in which the currencies of countries with less economic development and trade deficits tend to be overvalued.

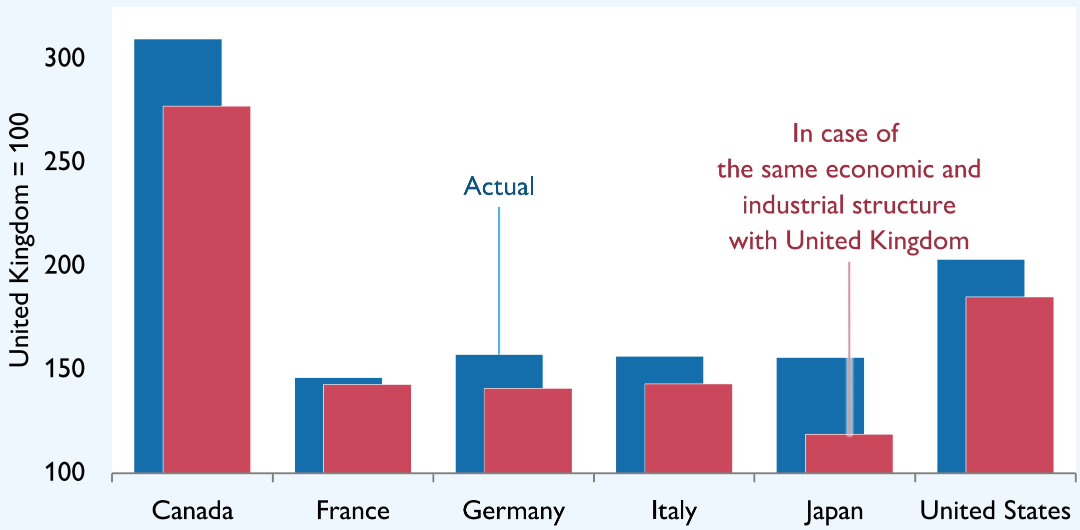
Figure 6 | Composition of value added [2019, compared with the United Kingdom]



Note: In 2015 prices
Source: Calculated based on the OECD "National Accounts"

If Germany and Japan had the same composition of value added by industry, in other words, the same economic and industrial structure, as the United Kingdom, their GDP intensity of final energy consumption would be 10% and 24% lower than they really are[6] (Figure 7). This will narrow the gaps with the United Kingdom considerably.

Figure 7 | GDP intensity of final energy consumption if the economic and industrial structure was the same as the United Kingdom [2019]



Source: Calculated based on the IEA "World Energy Balances" and the OECD "National Accounts"

In reality, not all countries can have a similar economic and industrial structure to the United Kingdom's – if every country specialised in services and finance, the world economy would not be viable. While

[6] The final energy consumption per unit of value added for each industry is calculated based on actual values of each country.

the economic and industrial structure has a significant impact on energy consumption, it is not explicitly considered when simply comparing GDP intensities; this should be kept in mind.

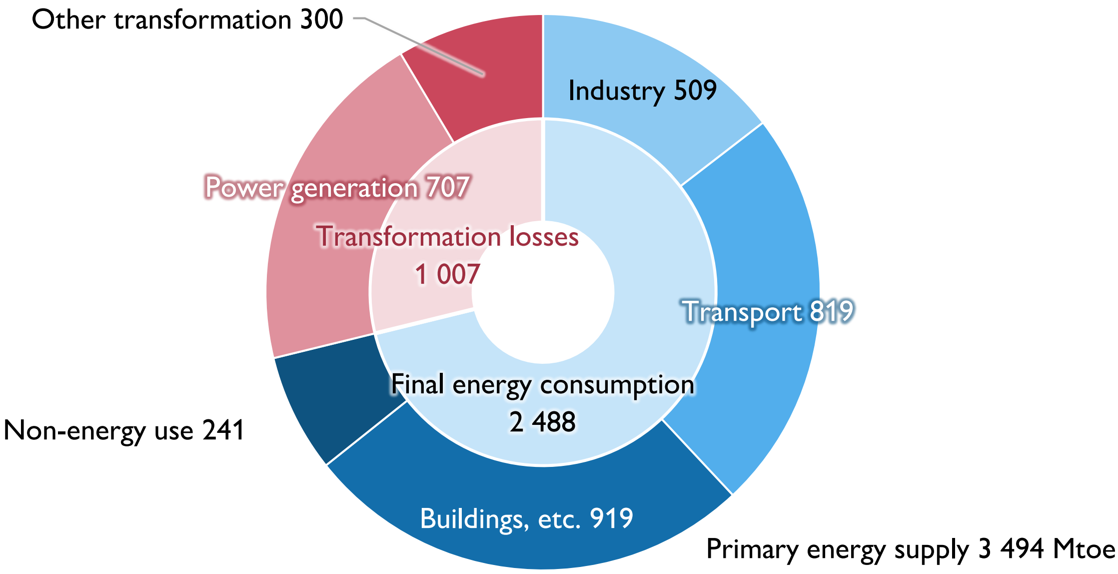
Caution warranted when evaluating progress in energy efficiency

In the previous sections, we described how exchange rates have a major impact on the *level* of GDP intensity of primary energy supply, which is used to evaluate energy efficiency, and its comparison between countries. In addition to this, attention must also be paid to certain factors when evaluating the progress of energy efficiency in terms of the *change* in the GDP intensity. In the following section, we assess what factors cause changes in the GDP intensity of primary energy supply by dividing the primary energy supply into its components: (1) final energy consumption, which represents the amount of energy actually used by end users, and (2) transformation loss, which is the amount of energy lost in transforming energy sources into other forms usable by end users.

Final energy consumption

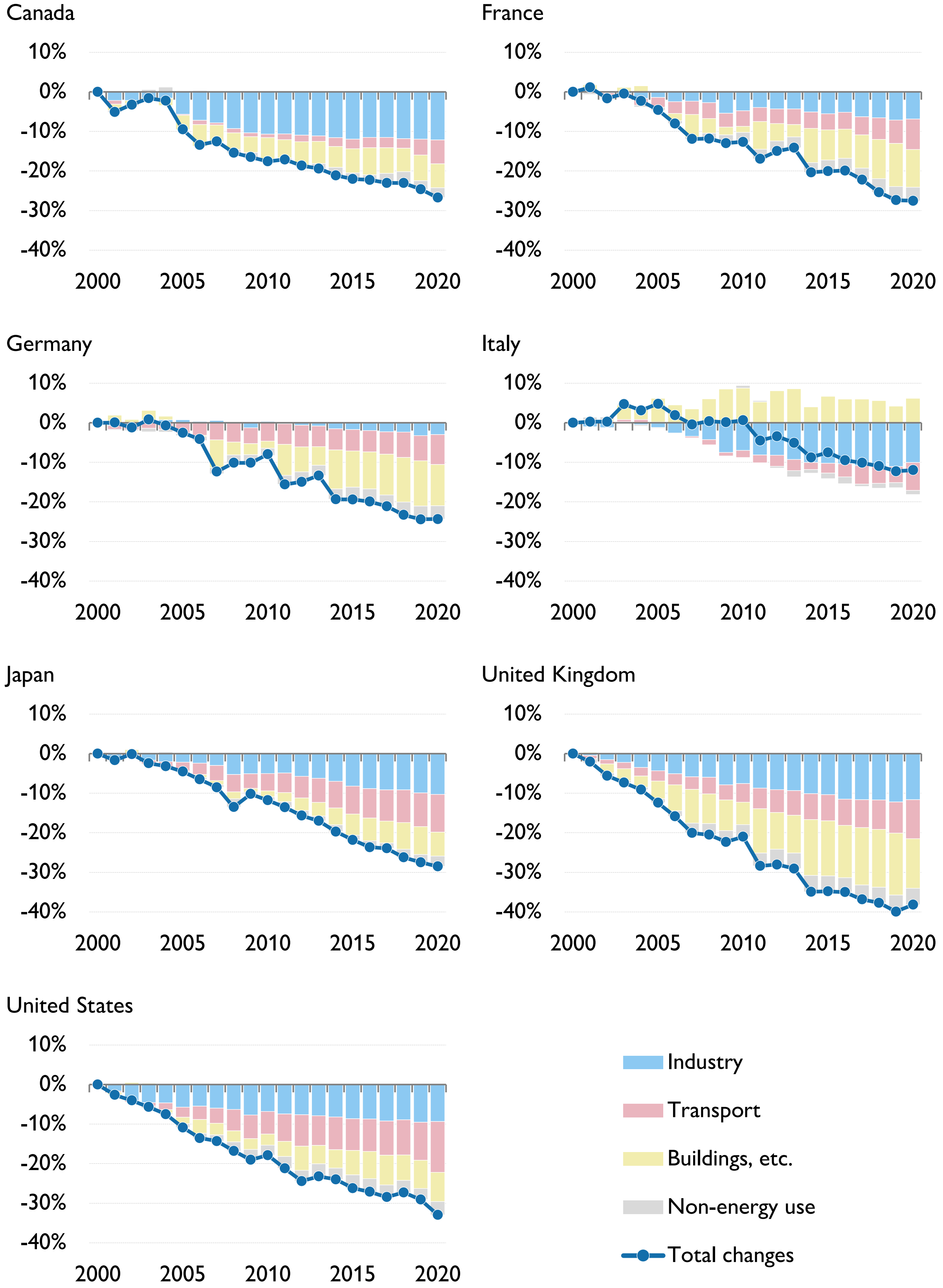
Areas of final energy consumption can be classified broadly into industry (mining, construction and manufacturing), transport, buildings, etc. (residential, commercial, agriculture, forestry and fisheries, and unclassified), and non-energy use sectors (Figure 8). The GDP intensity of final energy consumption has been decreasing for the past two decades in all G7 countries, and energy efficiency is considered to be improving also at the end-user level (Figure 9). In particular, North America has made significant progress in energy efficiency, though it still lags behind Europe and Japan in terms of energy efficiency levels. The United Kingdom and Germany, which are considered to be ahead of Japan in energy efficiency level, have made notable progress in energy efficiency in the buildings, etc., which drove the decrease in their GDP intensity of final energy consumption.

Figure 8 | Primary energy supply of G7 [2020]



Source: IEA “World Energy Balances 2022”

Figure 9 | Sector-based contribution to changes in GDP intensity of final energy consumption [vs. 2000]



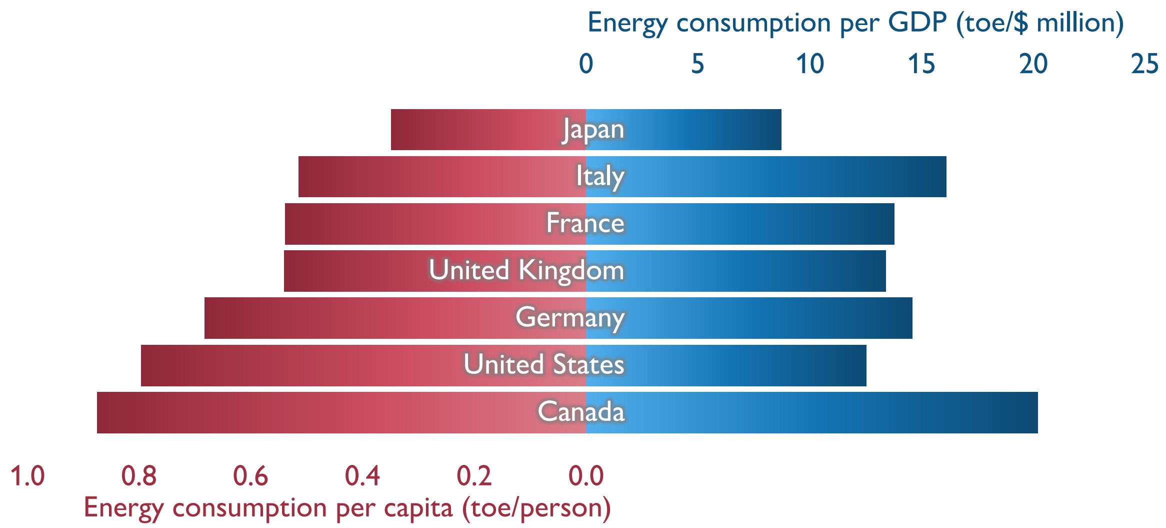
Source: Calculated based on the IEA "World Energy Balances" and the OECD "National Accounts"

The final energy consumption for industry[7], commercial, agriculture, forestry and fisheries, and non-energy use (chemicals industry) represents the amount of energy consumed finally for production activities in each sector/industry. Therefore, it would make sense to consider the amount of value added for each sector/industry as its amount of activity, and to use the energy consumption per unit of value added as an energy efficiency indicator.

In contrast, household energy consumption is not used for production activities. Households consume energy to satisfy the energy services they need for their daily lives. In emerging and developing economies, it is common for the amount of energy consumption to increase as income rises and living standards improve. However, advanced and other economies that already enjoy generally advanced living conditions are less likely to increase their energy consumption, which is a necessity, to even higher levels with an increase in income. Household energy consumption depends primarily on the temperature, stay-at-home rate, which has changed dramatically with the pandemic measures (COVID-19), and the energy efficiency of appliances and houses, which is directly related to energy efficiency at the microscopic level.

If we measure the energy efficiency in residential sector using energy consumption per GDP, the most efficient country is Japan, followed by the United States (Figure 10). However, as the United States is not generally regarded as highly advanced in terms of energy efficiency, this approach is rather unconvincing. For a comparison of G7 countries with similar economic development levels, energy consumption per capita appears to be a more credible indicator for residential energy efficiency than that per GDP. It should be noted, however, that both indicators are not adjusted for different climate conditions.

Figure 10 | Residential sector energy consumption per capita and per GDP [2020]



Source: Calculated based on the IEA "World Energy Balances", the OECD "National Accounts" and the World Bank "World Development Indicators"

Transport sector is both industry and residential sectors in nature. Freight transport, which involves energy consumption for the transportation of goods, may be closer to industry than residential. Passenger transport, on the other hand, consists largely of energy consumption by people's own cars ("personal cars"), which

[7] In principle, in the following section, industry consists of the following categories: mining, construction, primary metals, chemicals, non-metallic minerals, transport equipment, metal machinery and other machinery, food, paper, pulp and printing, textiles, and other manufacturing sectors. The reason for this treatment is because the OECD "National Accounts" does not categorise the value added data for primary metals for Japan into steel and non-ferrous metals.

are rarely related to production activities. Here, energy used for transport is assumed to be widely used to support the country's economic and social activities, and therefore, we regard energy consumption per unit of GDP as an energy efficiency indicator. In addition, for convenience, the same treatment is applied to the unclassified and non-energy use (other than chemicals), for which usage scenes are hard to specify.

According to the above, the GDP intensity of final energy consumption can be expressed as follows:

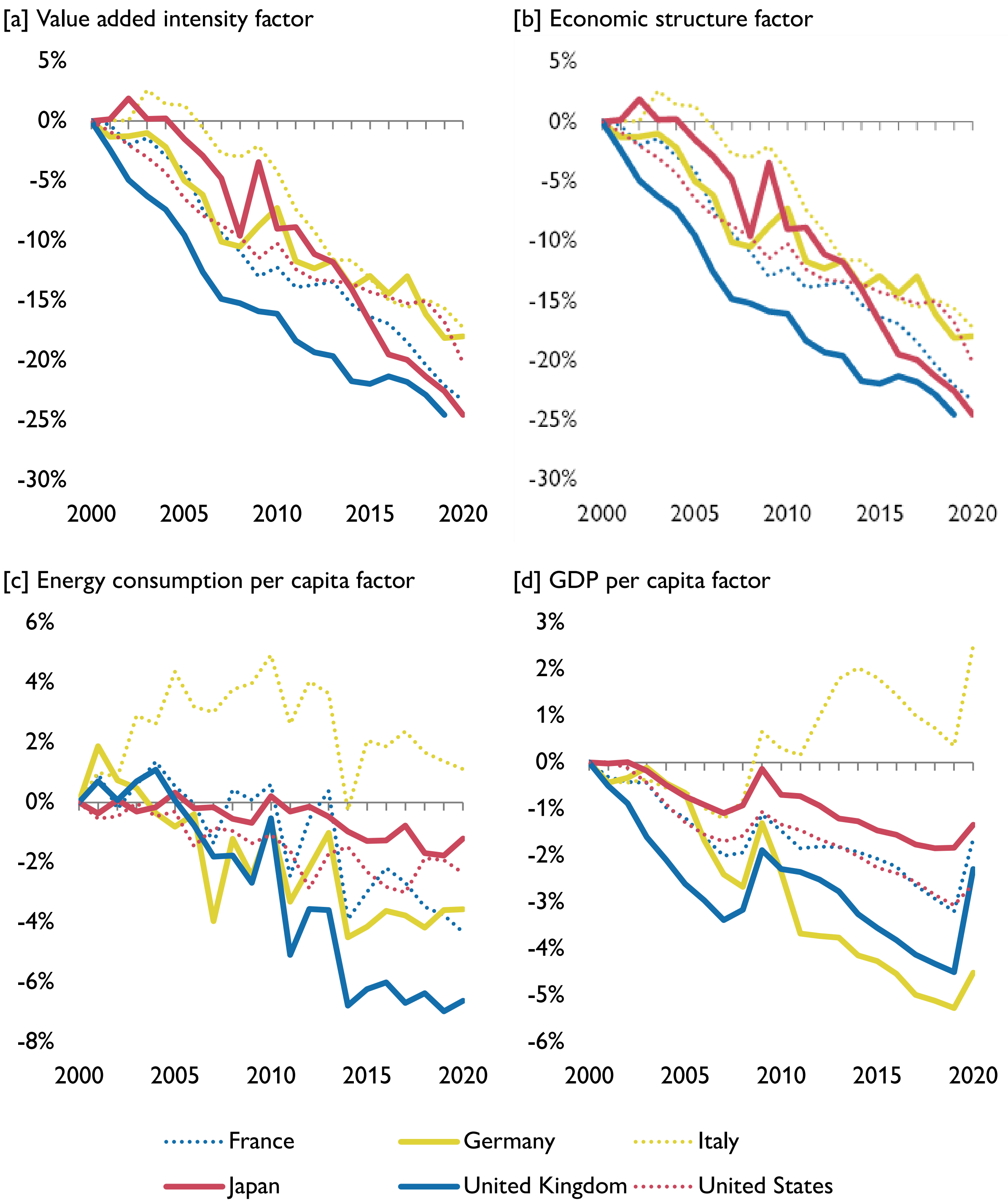
$$\frac{\text{Final energy consumption}}{\text{GDP}} = \sum_{i \in \text{Industry, commercial, agriculture, forestry and fisheries, non-energy use (chemical)}} \frac{\text{Energy consumption}_i}{\text{Value added}_i} \times \frac{\text{Value added}_i}{\text{GDP}} + \frac{\text{Energy consumption}_{\text{Residential}}}{\text{Population}} \times \left(\frac{\text{GDP}}{\text{Population}}\right)^{-1} + \sum_{i \in \text{Trasnsport, unclasiffied, non-energy use (other than chemical)}} \frac{\text{Energy consumption}_i}{\text{GDP}}.$$

Based on the equation above, changes in the GDP intensity of final energy consumption can be decomposed and reorganised into the following four factors: [a] "value added intensity factor", which is the contribution from the energy consumption per unit of value added (or GDP) and is a good indicator of energy efficiency (applied to industry, transport, commercial, agriculture, forestry and fisheries, non-energy use, and unclassified); [b] "economic structure factor", which is the contribution from the value added ratio of each industry against GDP and represents the economic and industrial structure (for industry, commercial, agriculture, forestry and fisheries, and non-energy use (chemical)); [c] "energy consumption per capita factor" (for residential), and [d] "GDP per capita factor" (for residential). Then, the change in the GDP intensity of final energy consumption was decomposed into the above factors for the G7 countries except Canada[8] (Figure 11).

Although Japan is said by some to be trailing the United Kingdom and Germany in energy efficiency, its value added intensity factor has been growing faster than those countries since the beginning of the 2010s, partly due to the electricity saving efforts following the Great East Japan Earthquake (Figure 11a). Its downward contribution surpassed that of Germany in 2013 and has come very close to that of the United Kingdom since 2016. Some attribute any "lack of progress in Japan's energy efficiency" to industry and the production sector, but such criticism is not valid.

[8] Canada was excluded because the OECD "National Accounts" does not contain the industry-based value added data for Canada prior to 2011. In addition, the United Kingdom was included in the analysis only through 2019 because the data for 2020 were not available.

Figure 11 | Contribution by factor to change in GDP intensity of final energy consumption [vs. 2000]



Source: Calculated based on the IEA "World Energy Balances", the OECD "National Accounts" and the World Bank "World Development Indicators"

The economic structure factor has a relatively large downward contribution in the United Kingdom (and the United States), where the manufacturing sector has declined and the service sector has expanded (Figure 11b). In contrast, in Germany, expansion of the energy-intensive industries has made an upward contribution. This may have a bearing on the recent direction of green transformation, but it must be noted that the economic structure factor's contribution to energy efficiency is purely the *result* of the change in the economy; changing the economic and industrial structure to improve energy efficiency is reversing this cause-effect relationship by nature. It would make sense to create new industries conducive to green transformation and the spillover effects will help revitalise the economy. However, putting too much weight on economic reform to achieve energy efficiency and decarbonisation may lead to the inappropriate exclusion of energy-intensive industries and carbon leakage, which could worsen the overall energy efficiency and hamper climate action. It is necessary to consider the possibility[9].

The energy consumption per capita factor tends to show a downward contribution except for Italy, indicating substantial progress in household energy conservation (Figure 11c). In the United Kingdom and Germany, high energy consumption due to their cold climates coupled with faster progress in energy efficiency than Japan has resulted in a significant downward contribution. Japan's energy consumption per capita is small to begin with, but its downward contribution was smaller in Japan than in Europe and the United States, even though the Top Runner program that began at the end of the 1990s should have had an effect. Japan is currently focusing on improving the energy efficiency of homes, but it may be worth considering the scope for further improvements.

One possible pitfall is the GDP per capita factor. GDP per capita itself has little meaning as a factor for energy efficiency. Nonetheless, when dealing explicitly with energy consumption per capita in residential sector, the GDP per capita factor is inherently present in the GDP intensity of final energy consumption as an energy efficiency indicator, though seldom noticed. This requires attention. Because Japan's economic growth is slow, the country enjoys only a limited downward contribution from an increase in GDP per capita compared to Germany and the United Kingdom (Figure 11d). Again, however, even if the GDP intensity of final energy consumption decreases thanks to the downward contribution of the GDP per capita factor, it does not mean that energy efficiency has fundamentally improved. In 2020, the GDP per capita factor recorded the greatest upward contribution since the 2008 financial crisis and the European debt crisis in all countries as their economies declined sharply due to COVID-19. Needless to say, this does not mean that their energy efficiency has deteriorated.

Transformation loss

The type of energy transformation that suffers the greatest transformation loss in terms of both amount and rate loss is power generation. In thermal power generation, approximately 60% of the energy input is lost during transformation. In comparison, the loss rate for other types of transformation is generally small, with only about 10% for coke production, which ranks second after power generation. Therefore, in this paper, we broadly classified transformation loss into power generation loss and other transformation loss. The GDP intensity of transformation loss was expressed by the following equation and was analysed:

$$\frac{\text{Transformation loss}}{\text{GDP}} = \frac{\text{Power generation loss}}{\text{GDP}} + \frac{\text{Other transformation loss}}{\text{GDP}},$$

[9] For example, the draft Basic Policy for the Realization of GX of the GX Implementation Council includes a clause that reads, "...promote industrial structural transformation and fundamental energy efficiency on both the supply and demand sides, including the manufacturing industry, such as steel, chemical, and others...". The goals to be set may differ greatly depending on what is considered as the scope of industrial structural transformation.

$$\frac{\text{Power generation loss}}{\text{GDP}} = \frac{\text{Final energy consumption}}{\text{GDP}} \times \frac{\text{Final electricity consumption}}{\text{Final energy consumption}} \times \frac{\text{Total electricity generated}}{\text{Final electricity consumption}} \times \sum_{i \in \text{Type of power generation}} \frac{\text{Electricity generated}_i}{\text{Total electricity generated}} \times \frac{\text{Power generation loss}_i}{\text{Electricity generated}_i},$$

$$\frac{\text{Other transformation loss}}{\text{GDP}} = \frac{\text{Final energy consumption}}{\text{GDP}} \times \frac{\text{Other transformation loss}}{\text{Final energy consumption}}.$$

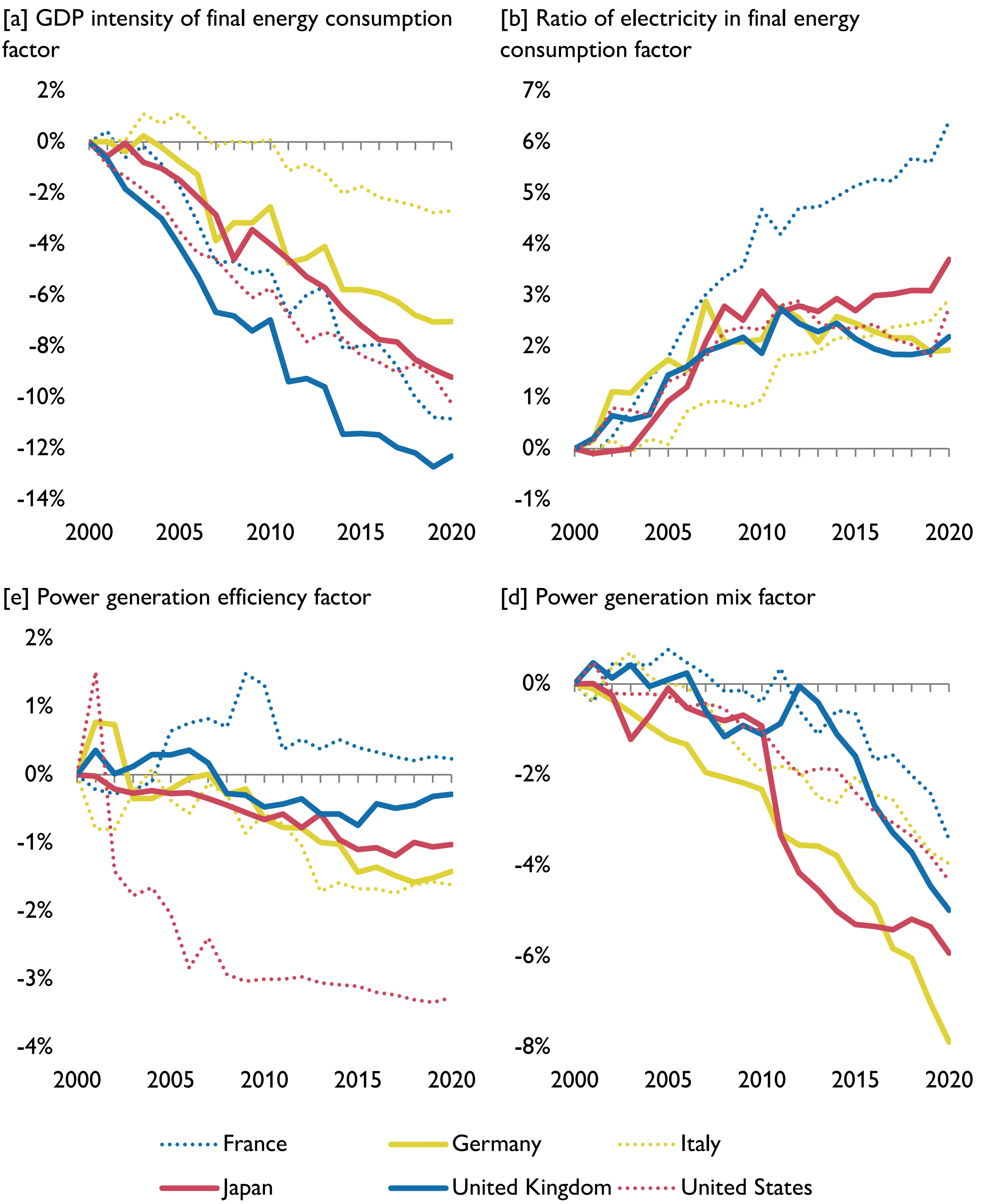
If we focus on the change in GDP intensity of transformation loss, as in the previous section, changes in the GDP intensity of transformation loss can be broken down and reorganised into the following six factors: [a] “GDP intensity of final energy consumption factor” (for power generation and other transformation); [b] “ratio of electricity in final energy consumption factor”; [c] “ratio of power transmission/distribution loss and own use, etc. factor”; [d] “power generation mix factor”; [e] “power generation efficiency factor”, and [f] “other transformation efficiency factor”. Figure 12 shows the main contributors to the change identified above.

The GDP intensity of final energy consumption strongly reflects the gaps in the rate of progress in energy efficiency between countries shown in Figure 9, with the United Kingdom seeing the largest downward contribution to its GDP intensity of transformation loss (Figure 12a). Furthermore, the contribution of the GDP intensity of final energy consumption becomes larger when the transformation loss is large. Being a major nuclear power producer, France is the only G7 country whose transformation loss exceeds half of its primary energy supply, due in part to the assumed efficiency of nuclear power generation (see below), resulting in the second largest downward contribution of its GDP intensity after the United Kingdom.

Electrification is expanding as societies become more sophisticated, making the ratio of electricity the only factor with an upward contribution in all countries (Figure 12b). The ratio of electricity is certain to increase going forward, as electrification with low-carbon electricity is viewed as a means to combat climate change. This makes it important to control the deterioration of energy efficiency caused by electrification. Japan has the fastest rate of electrification, with France ranked second. France, however, has a far higher upward contribution of ratio of electricity to its GDP intensity of transformation loss than other countries at 6.4%, due to its high ratio of transformation loss to primary energy supply.

Improving power generation efficiency is one of the key measures for energy conservation. In reality, however, the reduction in the GDP intensity of transformation loss that can be achieved by improving the power generation efficiency is not markedly large (Figure 12c). This is because it is not easy to greatly enhance the efficiency of power generation even with advanced technology, unless very old equipment is being replaced. In addition, the limited share of new installed power generation plants in the existing stock – especially in countries with slow power generation growth – also limits the downward contribution.

Figure 12 | Contribution to change in GDP intensity of transformation loss [vs. 2000]



Source: Calculated based on the IEA "World Energy Balances" and the OECD "National Accounts"

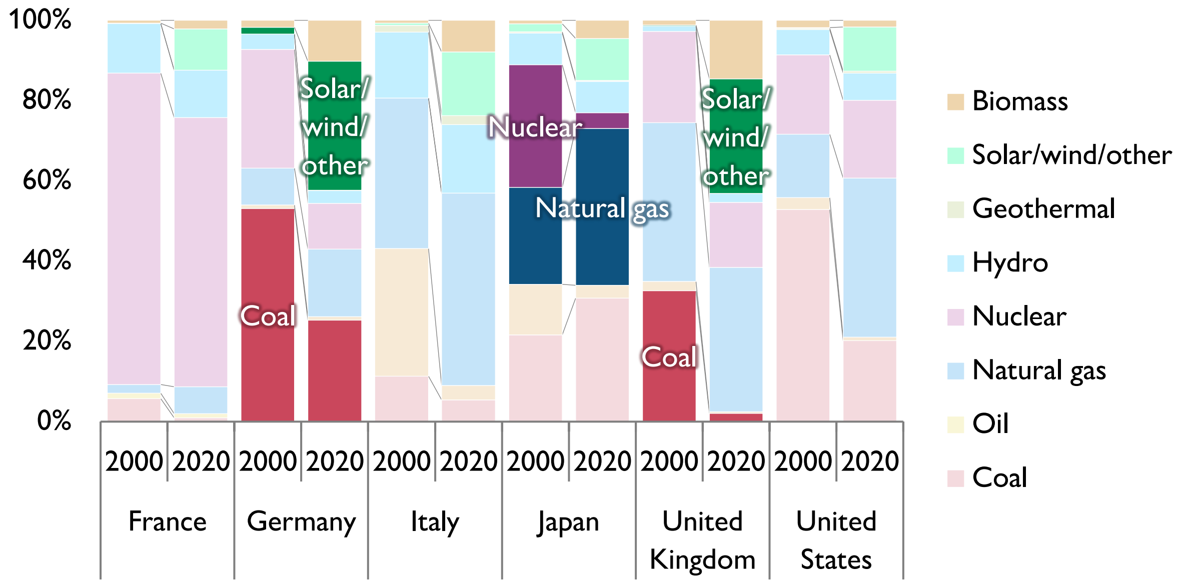
The power generation mix factor represents, for example, the reduction in transformation loss achieved by replacing low-efficiency coal-fired power generation with high-efficiency natural gas-fired power generation. However, the handling of primary electricity must be considered. The IEA's energy balance table assigns predetermined generation efficiency to power generation by nuclear, hydro and solar/wind/other, for which the amount of energy input cannot be measured directly; the amount of energy input is calculated backward from the assumed power generation efficiency and the amounts of electricity generated (Table 1). The power generation efficiency for the quickly expanding solar/wind/other and hydro is 100%, in other words, transformation losses are treated as 0%. This means that if thermal power generation is replaced by these, the calculated transformation loss will be drastically reduced. In other words, the power generation mix factor is a combination of both factors that are truly relevant and those that are relevant only in rules and calculations.

Table 1 | Assumed power generation efficiency of primary electricity in IEA statistics

Nuclear	Hydro	Geothermal	Solar/wind/other
33%	100%	10% in principle	100%

Germany and the United Kingdom (Figure 13), where solar photovoltaic (PV) and wind power generation combined now account for about 30% of total electricity generated, are seeing a significant downward contribution of the power generation mix factor (Figure 12d). Japan has also recorded a major downward contribution since 2011, largely due to the growth of solar PV power generation as well as the replacement of nuclear power generation, which was shut down after the Great East Japan Earthquake, with thermal power generation (whose average efficiency is about 45%). Meanwhile, the Kishida administration has reversed Japan's post-Earthquake nuclear policy and proposed the active use of nuclear power generation. If this policy is implemented, the power generation mix factor will serve to increase the GDP intensity of transformation loss.

Figure 13 | Power generation mix



Source: IEA "World Energy Balances"

Primary energy supply

Given that the GDP intensity of final energy consumption and of transformation loss can be broken down into the aforementioned factors, we can deduce that the GDP intensity of primary energy supply is also a combination of factors that are truly relevant to energy efficiency and those that are not (Table 2).

Table 2 | Contributors to the GDP intensity of primary energy supply

	Contributors to the GDP intensity of final energy consumption	Contributors to the GDP intensity of transformation loss
Factors that are fundamentally relevant to energy efficiency	● Value added intensity (Scope: all except residential) ● Energy consumption per capita (Scope: residential)	● Ratio of power transmission/distribution loss and own use, etc. ● Power generation mix (except for primary electricity) ● Power generation efficiency ● Other transformation efficiency
Factors with intermediate implications	● Economic structure (Scope: industry, commercial, etc., agriculture, forestry and fisheries, and non-energy use)	● Ratio of electricity in final energy consumption
Factors with little fundamental relevance	● GDP per capita (Scope: residential)	● Power generation mix (for primary electricity)
Factors with mixed implications		● GDP intensity of final energy consumption (see left column)

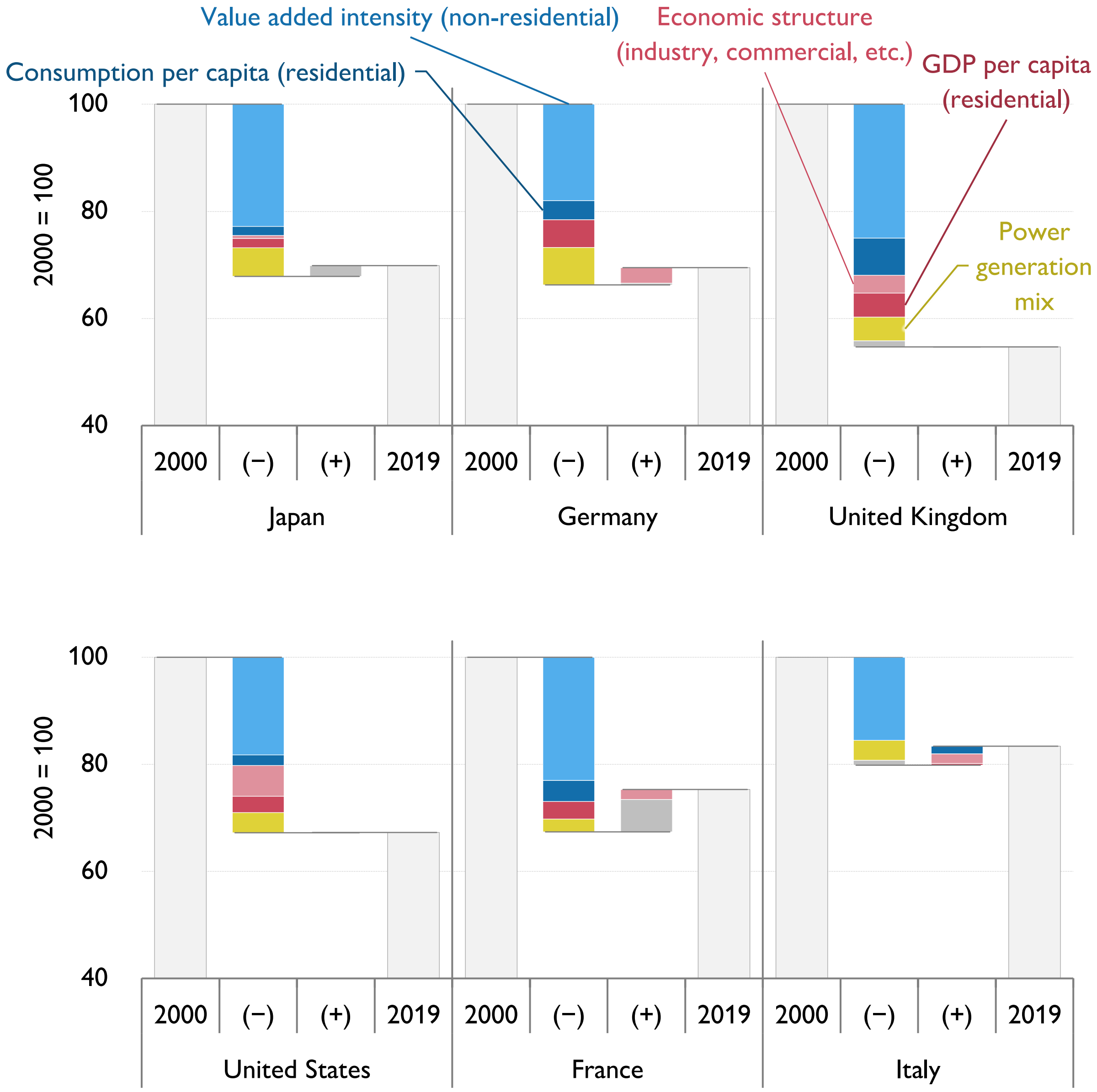
With this in mind, the contribution of each factor to the change in GDP intensity of primary energy supply was recalculated by combining the results of previous analyses and the outcome was charted as shown in Figure 14.

By the value added intensity factor, the factor most fundamentally relevant to energy efficiency, Japan reduced its GDP intensity of primary energy supply more than Germany did, although not by as much as the United Kingdom. Nevertheless, Japan lagged behind Germany in the reduction rate of the GDP intensity of primary energy supply. One reason is the difference in the negative contribution of another fundamental energy efficiency factor, the energy consumption per capita for households. When discussing energy efficiency, the focus tends to be on industry, mainly manufacturing, but our finding is a warning that such focus is not sufficient.

The United Kingdom is undergoing a remarkable economic shift from manufacturing to an information- and service-based industry, and the country is transforming its economic and industrial structure into a non-energy intensive one. As a result, its economic structure factor drove down the GDP intensity of primary energy supply on a scale second only to that of the United States. However, it is inherently inappropriate to treat the economic structure factor as if it were a controllable means of energy efficiency; it is energy that serves the economy, and not the other way round.

For Japan, which is suffering from low economic growth, GDP per capita had a contribution of only one-third that of Germany and 40% that of the United Kingdom, slowing the rate of progress in overall energy efficiency. However, like the economic structure factor, the GDP factor per capita factor is a *result* of economic growth, and it would be illogical to strive for economic growth with the aim of its downward contribution to energy intensity. Thus, the contribution of this factor that have little fundamental relevance for energy efficiency may be rather discarded.

Figure 14 | GDP intensity of primary energy supply and contributions to its changes



Source: Calculated based on the IEA "World Energy Balances", the OECD "National Accounts" and the World Bank "World Development Indicators"

The negative contribution from the power generation mix factor was smaller for Japan than for Germany but was bigger than for the United Kingdom. However, if we look at the largest changes in the power generation mix, Germany and the United Kingdom have replaced coal with solar PVs and wind, which are assumed to have no transformation loss, whereas Japan has replaced nuclear power, whose assumed power generation efficiency is lower than that of thermal power, with natural gas, meaning that the actions of these countries have completely different implications in terms of low-carbonisation (Figure 13). The power generation mix factor varies greatly depending on the assumed power generation efficiency of primary electricity, which is "plastic". This makes it difficult to treat the power generation mix factor as a measure of energy efficiency in these days when efforts to low carbonisation are being made and the introduction of solar PVs and wind is progressing rapidly. For example, if geothermal, which is assigned an assumed power generation efficiency of only 10% in principle, replaces other power sources, the GDP intensity of primary energy supply will actually worsen.

What the GDP intensity of primary energy supply tells us

The GDP intensity of primary energy supply is used frequently and is adopted as an energy efficiency indicator because it is intuitive, easy to understand, and requires little data for calculation. However, it is an indicator that disregards various factors that actually affect energy efficiency. It also contains elements that appear irrelevant to the evaluation of energy efficiency, with an influence that cannot be ignored.

The GDP intensity of primary energy supply is a particularly convenient indicator, and its use should not be ruled out. However, when grasping the real picture of energy efficiency targets through international comparisons, running a plan-do-check-act (PDCA) cycle for progress in energy efficiency by monitoring the changes over time, and projecting the future by extrapolation, it is essential to understand the characteristics and limitations of this indicator.

An in-depth examination suggests that Japan's energy efficiency is not substantially inferior to that of Europe. However, the fact that Japan's advantage in energy efficiency is no longer immediately obvious suggests that Japan needs to consider what else it can do as a world leader in energy efficiency, while also wholeheartedly commending Europe's progress.

Carbon Neutrality and Trade Challenges
-Focusing on Carbon Border Adjustment Mechanism◆

Miki Yanagi*

Points

- ✓ The European Union (EU) has promoted the consideration of the Carbon Border Adjustment Mechanism (CBAM) towards carbon neutrality, planning to legislate the CBAM within 2022[1]. This is a scheme to adjust carbon pricing costs during the production of goods at the border. Carbon pricing imposes costs on emitters according to their amounts of CO_2 emissions to internalize their external cost on the environment, incentivizing them to cut emissions.

- ✓ The unprecedented mechanism is feared to be incompatible with most-favored-nation treatment and other basic principles under the General Agreement on Tariffs and Trade (GATT). If so, one of the challenges is whether the CBAM could be justified under GATT Article XX for general exceptions (The Chapeau, and its paragraphs).

- ✓ The United States and the EU are discussing methodologies for monitoring emissions from steel and aluminum in their negotiations under Article 232 of the 1962 U.S. Trade Expansion Act, "Global Arrangement on Sustainable Steel and Aluminum".

- ✓ The EU CBAM is feared to come under fire from developing countries, which have historically accumulated less emissions than developed countries. It has the potential to deepen the north-south division and result in exclusionary economic blocs.

- ✓ Rules-based Japan is expected to contribute to resolving carbon neutrality and trade challenges. For Japan, with its economy supported by exports, it may become important to consider a border adjustment mechanism with export rebate that is compatible with WTO rules using carbon tax rather than Emission Trading[2].

The Paris Agreement adopted at the 21st Conference of Parties (COP21) to the United Nations Framework Convention on Climate Change (UNFCCC) in 2015, many countries have set forth a goal of achieving carbon neutrality, or net-zero emissions, by 2050. In recent years, meanwhile, the CBAM and other issues regarding carbon neutrality and trade nexus have arisen.

This paper aims to explain the controversial CBAM. The following explains the background, outlines the CBAM mechanism in general, details the EU's consideration of the CBAM and discusses arguments in the United States and Japan

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1 This article was written by author in December 2022, based on the Commission's proposal before the final agreement on EU carbon border adjustment was reached by the European Parliament and the Council on April 25, 2023. The regulation then officially entered into force the day following its publication in the Official Journal of the EU on 16 May 2023. Further detail rule for emission accounting is published as Implementing Act and Delegated Act.

2 In Japan, Green Transformation (GX) related legislation was passed and enacted by the 211 Diet on May 2023, which deal with Japanese Emission Trading Systems. Studies are underway to make the ETS operational in FY2026. A phased introduction of "auctions" for power utilities is being considered starting in FY2033.

and under the UNFCCC. Furthermore, this paper analyzes the compatibility of CBAM with WTO rules using previous studies and provides recommendations and prospects.

Emerging contacts between carbon neutrality and trade

In the EU, Ursula von der Leyen, who was inaugurated as president of the European Commission in December 2019, attracted attention by positioning climate change actions as a top policy priority and proposing the introduction of Carbon Border Adjustments Mechanism. The EU is considering its "Fit for 55" policy package to realize the goal of cutting greenhouse gas emissions by 55% from 1990 to 2030 under its Nationally Determined Contributions (NDCs) for the Paris Agreement.

Joe Biden took up the U.S. presidency in January 2021 and achieved the United States rejoin the Paris Agreement. During his presidential election campaigns, he promised to introduce Carbon Border Adjustment to protect U.S. manufacturers and workers.

The Paris Agreement was adopted in a manner to achieve a sensitive balance amid the north-south confrontation and various national political conditions. However, international asymmetries in costs for climate change countermeasures are emerging as NDC's ambitions are enhanced. Momentum is now rising to consider trade measures to level the playing field, and correct unfair competitive conditions attributable to such cost gaps.

In July 2021, the EU launched talks on the CBAM to be combined with the EU Emission Trade System (EU-ETS). The European Commission, the EU's executive arms, came up with the world's first CBAM design. While energy and other price hikes have become a social issue since Russia's invasion of Ukraine, the EU is reportedly still considering the CBAM.

Nexus between climate change and trade are not limited to border adjustments but are diverse.

In October 2021, for instance, the United States and the EU agreed not to apply duties on steel and aluminum imports that the Trump administration imposed under Section 232 of the 1962 Trade Expansion Act, and related tariffs. The agreement called for establishing a global arrangement to address global overcapacity in the steel sector while reducing trade flows that have high carbon intensity. Within two years, they will establish a methodology to measure emissions from steel and aluminum goods and implement an initiative open to like-minded countries.

At the 26th Conference of Parties to the United Nations Framework Convention on Climate Change (UNFCCC/COP26) in 2021, the United States launched the First Movers Coalition as a platform for global companies to pledge to purchase "green steel" and other goods and technologies required for carbon neutrality to create initial demand for them. The coalition aims to develop markets for decarbonized goods, having some impact on trade.

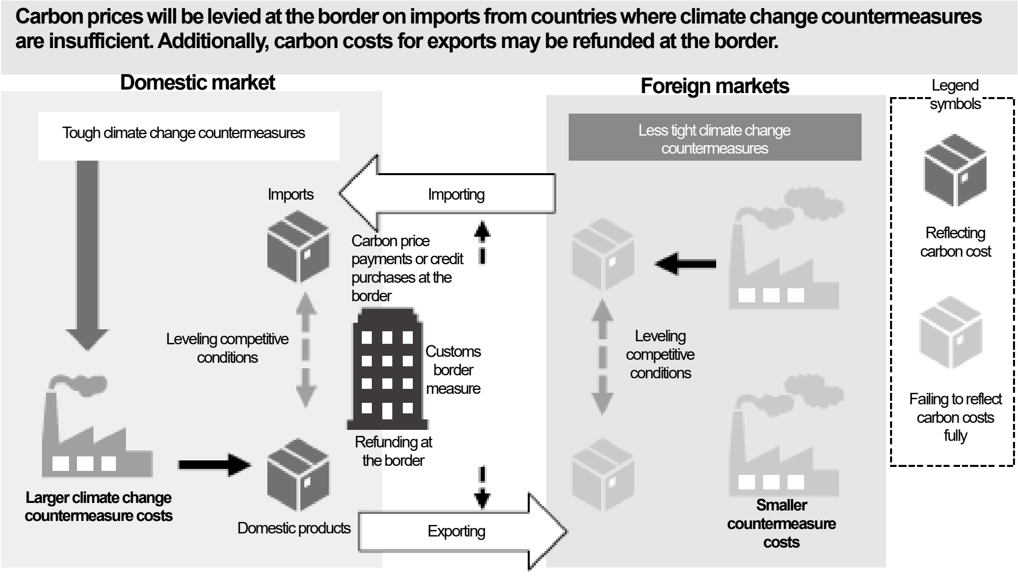
At the World Trade Organization (WTO), 71 economies, including the United States and China, have participated in the Trade and Environmental Sustainability Structured Discussions (TESSD) to discuss whether trade-related climate measures or policies would be compatible with WTO rules and principles and how these measures or policies would contribute to climate and environment goals and commitments.

The Group of Seven (G7) and other forums, as well as the International Monetary Fund (IMF), the Organization for Economic Cooperation and Development (OECD) and other international organizations, are also considering methodologies to measure emissions included in products and carbon costs for their production. These methodologies will be required for border adjustments.

In this way, rulemaking regarding carbon neutrality and trade has become a significant issue towards the realization of a carbon neutral society. As rulemaking talks now focus on carbon border adjustments, the following details the adjustments:

What are carbon border adjustments?

Carbon border adjustment would be used by countries that shoulder heavy climate change policy costs as impose tax, surcharges, credit purchase obligations or the like on imported goods from those that do not take sufficient climate change countermeasures. As of the writing of this chapter, no country or region has introduced carbon border adjustments that are designed to prevent carbon leakage (Fig. 1).



If a country imposes carbon costs only on domestic companies, they may be disadvantaged in international competition. This is why border adjustments is implemented to level the playing field and prevent carbon leakage.

Fig. 1 The structure of Carbon Border Adjustments

Source: Prepared by the author from METI (2010) "On 2010 Review Report on Unfair Trade Practices"

Carbon leakage refers to a situation where global emissions fail to decline as a country enhances climate change countermeasures at the cost of a production drop and another country with lower policy costs regarding carbon emissions increases production. In such a situation, domestic products in a country are replaced with imports that emit more carbon, leading to an adverse economic impact that would force the country's industries to be transferred abroad.

The EU and some others have grown interested in carbon border adjustment in recent years because they must reduce the adverse effects of their policies for raising carbon emission costs on their domestic industries and workers.

To avoid carbon leakage, a country may impose the same carbon costs as its own on imports and refund the equivalent to once-imposed costs for exports. In this way, the same carbon costs are imposed on domestic products and imports in one country, with its products being exported without carbon costs. This means that border carbon adjustments are useful for a country to enhance climate change countermeasures while preventing carbon leakage. Conceptually, carbon border adjustments can be summarized in this way. For their implementation, however, detailed institutional designs are required. Marcu et al. (2020)[1] indicated eight major components of an institutional design (Table 1).

Table 1 Carbon border adjustment design components

Design elements	Design options
1. Coverage of trade flows	Imports only / including rebate for exports/ their combination
2. Policy mechanism (Domestic systems for adjustment)	Carbon tax, emissions trading system / regulatory measures / both
3. Geographic scope	Exemption of climate leader countries / exemption of least developed countries (LDCs)
4. Sectoral scope	Limited to basic materials and electricity / expanding the scope to include complex goods
5. Emissions scope	Direct emissions at plants (Scope 1) / including purchased electricity and steam (Scope 2) / Lifecycle emissions including emissions from mining and final consumption (Scope 3)
6. Determination of embedded emissions (estimated for each good)	Actual emissions from each plant or company / benchmarks (best practice, average) Whether to combine benchmarks with voluntary notification using international standards
7. Carbon prices for calculation of adjustment	Equivalent to or less than domestic carbon prices (carbon tax, emissions trading system, regulations, etc.) in principle. Considering exporters' carbon prices that are paid in export countries.
8. Use of revenue	Domestic environmental measures / support for developing countries

Source: The author added options for each of the elements based on the elements by Marcu et al. (2020)

Depending on the selection and combination of these components, leakage-reducing effects, legal feasibility, and technological and management feasibility may differ. Basically, no design exists to produce excellent results in all aspects. Some elements and their effects are traded off with each other. Because of the lack of institutional precedent, no model combination of the elements has been found.

EU-ETS and CBAM

The EU is considering combining EU-ETS with the CBAM. Table 2 summarizes the CBAM proposal in line with the eight elements. Some important points of the proposal are discussed below.

Table 2 Elements of European Commission CBAM proposal

Design elements	Design options
1. Coverage of trade flows	**Adjustment for imports only** / including rebate on exports / their combination
2. Policy mechanism (Domestic systems for adjustment)	Carbon tax, **explicit carbon pricing through the EU-ETS** / regulatory measures, including implicit carbon pricing / both
3. Geographic scope	**All countries** / exemption of LDCs / specific countries
4. Sectoral scope	**Limited to materials vulnerable to carbon cost impact** / expanding the scope to include complex goods[3]
5. Emissions scope	**Limited to direct emissions** / Scopes 1 & 2 [4]/ wider scope (*Including Scope 2 during a transitional period)
6. Determination of embedded emissions (estimated for each good)	**Requirement for reporting actual emissions from each good** (prorated according to weight / prorated according to prices / prorated according to broken down process. **Prorating methods are unknown**.)
7. Carbon prices for calculation of the adjustment	**Emissions from goods at each company or plant are multiplied by EU-ETS carbon prices. Only exporters' explicit carbon pricing is taken into account.** / benchmarks / + voluntary reporting when emissions are below benchmarks.
8. Use of revenue	Financial resources for the EU (called "own resources", estimated revenue at €2.1 billion for 2030.)

Note: Underlined parts are from the European Commission proposal.

Source: Prepared by the author from the European Commission proposal.

1. Overview of EU-ETS

The EU-ETS implements a "cap-and-trade" regulation for restricting the total amount of emissions. The EU-ETS has been in place since its introduction, with emission allowances decreasing over time. The EU-ETS covers combustion and manufacturing installations (e.g., 20-megawatt or larger combustion installations, pig iron production installations, etc.), targeting carbon intensive sectors.[2)] Its fourth phase started in 2021.

Free allowances under the EU-ETS are a key issue related to the CBAM. Free allowances are allocated to carbon intensive sectors with high export and import shares in sales to level the playing field.

"Sectors producing over 90 % of industrial emissions received as free allowances for free," according to the European Court of Auditors (2020). Particularly, the steel sector received free allowances equivalent to some 120% of its actual emissions in 2018.[3)] In 2020, blast furnaces in the steel sector could have received free allowances equivalent to some 130% of actual emissions in 2020.[4)] Unspent free allowances can be transferred to a subsequent phase, so-called "banking". Fee

[3] European commission will submit a report on products further down the value chain of the goods by 2024, at latest according to the regulation published in the Official Journal of the EU.

[4] direct emissions (*Steel and aluminum, Hydrogen) and indirect emissions (*cement, fertilizer, electricity) published in the Official Journal of the EU

allowances transferred to 2013 and on can be used indefinitely, according to an EU-ETS Directive article.

Since 2021, auction prices of emission allowances have continued to rewrite record highs due to energy price spikes. The benchmark price topped €50 per ton in May 2021 and rose close to €100/t in February 2022.

2. Design of EU CBAM

The EU is considering the design of the CBAM in a bid to legislate the CBAM before the end of 2022. In the run-up to the legislation, the European Commission, the EU's executive branch, came up with a proposal first. Later, the European Parliament as the legislative branch and the Council discussed amendments to the proposal. Finally, the European Parliament, the Council and the European Commission will reach an agreement through their trialogue process. As of the writing of this paper, the European Parliament and the Council have completed the consideration of their respective amendments. The trialogue is now under process. In the following, this paper examines the European Commission proposal as the basis for the CBAM design and checks symbolic items in European Parliament and Council amendments available as of the writing of this paper in October 2022.

(1) European Commission proposal [5)]

The European Commission published its CBAM proposal in July 2021. The proposal subjected iron and steel, cement, aluminum, fertilizers and imported electricity to the CBAM. EU imports from Japan in the five sectors are extremely limited (no electricity import from Japan).[6)]

The proposal set forth a transition period between 2023 and 2025, during which importers will be required to report the amounts of embedded emissions from imported goods. From 2026, they will be required to pay for CBAM certificates according to emissions from imported goods. CBAM certificates will be sold at week-earlier EU-ETS market prices, while importers pay for CBAM certificates according to emissions from imports. Payments for CBAM certificates will be effective import imposition. Carbon prices in countries of origin for imports will be adjusted upon payments for CBAM certificates. Then, EU-ETS free allowances will be reduced, with the equivalent to the reduction being replaced with CBAM certificates, as discussed later. Revenue from CBAM certificates is planned to become financial resources for the EU (new "own resources"). Such revenue is estimated at €2.1 billion for 2030. Table 2 summarizes the European Commission proposal according to the eight elements given in Table 1.

EU-ETS free allowances will be reduced by 10 percentage points each year over 10 years from 2026 for the commencement of payments for CBAM certificates, being phased out by 2035. In line with the phaseout, CBAM certificates will be increased by 10 percentage points each year from 2026, covering all emissions from imported goods from 2035. CBAM certificates will thus replace free allowances completely in 2035.

(2) European Parliament and Council Amendments

In June 2022, the European Parliament and the Council came up with amendments to the European Commission proposal. Particular amendments is as follow:

・ Expansion of sector and goods

The European Parliament amendments proposal added chemicals (organic chemicals, hydrogen, and ammonia) and polymers (plastics and plastic molding) to the five sectors proposed by the European Commission. The added organic chemicals and polymers are among massive imports from the United States, leading to concern about the EU's political dispute with the United States. The Council amendments expanded downstream goods for the five sectors proposed by the European Commission.

・ Expansion of the emissions scope

Regarding the emissions scope for the CBAM, the Council amendments almost endorsed the European Commission proposal that subjected direct emissions alone to the CBAM. However, the European Parliament amendments added indirect emissions (embedded emissions for purchased energy including electricity, so-called "Scope 2").

・ **Period for replacement of free allowances of EU-ETS with CBAM**

The European Commission proposal called for the replacement over 10 years between 2026 and 2035, which was almost accepted by the Council. However, the European Parliament came up with a six-year replacement period between 2027 and 2032.

・ **Export rebates**

While the European Commission proposal and the Council amendments proposal did not include any export rebates, the European Parliament amendments proposal included effective export rebates that take the form of a continuation of free allowances for goods for exports to third countries that do not have any carbon pricing systems similar to the EU-ETS.

Non-EU Discussions on Carbon Border Measure

Although only the EU is considering a specific carbon border adjustment mechanism, I would like to outline discussions on such border measures in the United States and Japan and under the United Nations Framework Convention on Climate Change (UNFCCC).

1. U.S.

In the United States, an initiative to legislate an emissions trading system gained momentum just after the inauguration of the Obama administration. The Waxman-Markey Bill (H.R. 2454 the American Clean Energy and Security Act of 2009), which cleared the House of Representatives in 2009, included a mechanism for the president to require importers to purchase “International emission allowances” if carbon leakage through emissions trading is identified. However, the bill failed to pass the Senate and was scrapped.

As noted earlier, current President Biden included carbon border adjustments into his presidential election campaign promises. After his inauguration, a Senator proposed a relevant bill, but the bill has failed to be considered fully in Congress. This may be because the United States has no nationwide carbon pricing system for adjustment.

2. Japan

The Japanese government set forth a basic approach to carbon border adjustment measures in its Green Growth Strategy considered in 2021. It called for taking the following four measures while considering a domestic carbon pricing system:

(1) Consider possible actions for carbon border adjustment measures with close attention to discussions taking place in other countries, with a prerequisite that the carbon border adjustment measures are designed to be consistent with WTO rules.

(2) Lead the development and application of global rules on measurement/evaluation methods for carbon emissions per product unit that are internationally reliable in terms of both accuracy and feasibility (e.g., development of ISO standards). Promote data transparency securement.

(3) Verify carbon costs that are associated with products subject to carbon border adjustment measures in Japan and countries that implement the measures.

(4) Address carbon border adjustment measures in cooperation with like-minded countries from the perspective of preventing carbon leakage and ensuring fair competitive conditions.

3. UNFCCC

Article 3-5 of the UNFCCC reads, “Measures taken to combat climate change, including unilateral ones, should not constitute a means of arbitrary or unjustifiable discrimination or a disguised restriction on international trade." This quotes the chapeau of Article XX of GATT.

The Paris Agreement, adopted at the conference of the parties to the UNFCCC in 2015, has no provision regarding border measures.

Column: Germany-proposed Climate Club

In 2022, when Germany took the chair of the Group of Seven, German Chancellor Olaf Scholz advocated a Climate Club to address carbon leakage. The G7 summit communique in June stated that the G7 would seek to establish an open, cooperative international Climate Club consistent with international rules by the end of 2022. The G7 will enhance talks with major emitters, the Group of 20, and developing countries towards the establishment. The club will address carbon leakage involving carbon emission-intensive goods through the enhancement of national emission reduction goals and emission measuring and reporting mechanisms under the Paris Agreement.

The export-oriented German business community appeared reluctant to accept the EU CBAM that could invite retaliatory measures by export destination countries. As a result, there had been a lot of attention on whether the Climate Club would replace the EU CBAM.

Compatibility with WTO rules

Carbon border adjustments represent policy intervention in trade, indicating that their compatibility with WTO rules will become a controversial issue.

1. Proposals in earlier studies

There are many earlier studies on the issue.

For instance, former WTO Appellate Body member Hillman (2013)[7] advocates an approach combining a carbon tax in the form of an indirect tax[8] like the consumption tax with border adjustment measures including rebates on exports. The approach represents the mutatis mutandis application of consumption tax border adjustments based on Articles II.2 and III.2 of the GATT to a carbon tax. This assumes that if the approach is difficult to justify with Article II or III, general exceptions under Article XX will be used. The study concludes that export rebates can be designed as compatible with the WTO Agreements because "the WTO rules on export subsidies permit a tax on domestically produced fossil fuels to be rebated when a product is exported, provided that the rebate is not larger than the actual tax levied on 'like' products 'when sold for domestic consumption. It also points out that many problems remain as open questions, including whether the internal tax in Article II.2 can be interpreted widely and whether a carbon tax on processes can be adjusted.

Regarding the exemption of least developed countries (LDCs) and others from border adjustments, the paper recommends the exemption of countries that have emitted little CO_2 in the past, based on "the requirement that such measures are not applied in a manner which would constitute a means of arbitrary or unjustifiable discrimination between countries where the same conditions prevail" in GATT Article XX of the GATT and the principle of "Common But Differentiated Responsibilities and Respective Capabilities (CBDR-RC)" in Article 3 of the UNFCCC.

Mehling et al (2019)[9] also proposed a carbon border adjustment design based on earlier studies and precedents in the Appellate Body of WTO. The paper describes carbon border adjustments as "the only unilateral policy option" that can help level uneven carbon constraints and offers both effective protection against carbon leakage and an incentive for other countries to strengthen their climate efforts, at a time when concerns exist on heterogeneous and asymmetrical domestic climate efforts under the Paris Agreement and carbon leakage. Based on the Appellate Body Report, Brazil—Measures Affecting Imports of Retreaded Tyres [10] where relations between the chapeau and each item of Article XX were questioned, the paper concludes that whether any carbon border adjustments can be harmonized with policy purposes is important.

This means that carbon border adjustments should be designed not only to level the playing field but also to contribute to the purpose of emission reduction. In this sense, the paper pointed out that export rebates could create an incentive for carbon emissions and undermine the justification of a carbon border adjustment based on Article XX.

Article I stipulates the Most-Favored-Nation treatment for one country to be provided to other countries, but allows exceptions for developing countries or LDCs. As LDCs emit little carbon, their exemption from carbon border adjustments may not run counter to the purpose of emission reduction. Given the European Commission's conditions for Tariff Preferences for developing countries, part of the revenue from carbon border adjustments should be used for supporting LDCs, according to the paper.

The above two proposals on carbon border adjustment were given in previous studies. For more details, see "2022 Report on Compliance by Major Trading Partners with Trade Agreements"[11] by the Ministry of Economy, Trade and Industry, Japan which generally and carefully covers arguments regarding carbon border adjustments' compatibility with WTO rules based on Appellate Body Reports.

2. Discussion points on EU CBAM

The CBAM being considered in the EU will also be subject to debate on its compatibility with WTO rules if it reaches a trialogue agreement among the European Parliament, the Council, and the Commission. At the time of writing this paper, the final CBAM institutional design is yet available, it is premature to discuss whether the EU CBAM is compatible with WTO rules. However, some experts have raised some points of the CBAM that could run counter to the GATT. For instance, Bacchus (2021)[12] points out that the EU CBAM could run counter to Article I of the GATT on the most-favored-nation treatment, Article II on schedules of concessions and Article III on the national treatment of internal taxation and regulation. The paper also notes the EU will likely intend to set up the CBAM as an internal regulation (Article III.4) rather than a customs measure.

The EU CBAM could have a problem with the "like products" requirement of GATT Article III. CBAM charges would be calculated based on embedded carbon emissions, if this is considered to discriminate against like products.

CBAM determines the size of the burden based on carbon content, if this is considered to discriminate against like products.

If the CBAM violates Article III, the justification of the CBAM under the chapeau and each item of Article XX on general exceptions (health and environmental purposes such as the restoration of the atmosphere before warming) may become an issue. Export rebates, as noted by Mehling et al. (2019), are difficult to be interpreted as compatible with the purpose of emission reduction and may not be compatible with Article XX.

While unspent free allowances under the EU-ETS ("Banking") can be transferred to a subsequent period, imports subject to the CBAM have no access to such allowances, indicating the discrimination of domestic products from imports.

Recommendations

Carbon border adjustment represents an attempt to fill international carbon price gaps ("asymmetry") at the border in preparation for carbon price hikes accompanying decarbonization, bringing to light on various issues between trade and climate change policies. Carbon price gaps, their asymmetry arise as emission reduction targets pledged as Nationally Determined Contributions under the Paris Agreement have different ambitions, called "asymmetry". Particularly, the EU, which attempts to enhance emission reduction through the EU-ETS and other measures under the goal of cutting emissions by 55% from 1990 by 2030, is planning to introduce the CBAM.

While the EU CBAM is planned to give consideration to carbon costs in countries of origin for imports, proposals cover only explicit carbon taxes and emissions trading systems. The proposals fail to take into account the diversity of carbon policy measures in countries including Japan, lacking flexibility. The EU CBAM may come under fire from developing countries from the viewpoint of responsibilities for accumulated emissions (Carbon Budget) and equity in the context of Common But Differentiated Responsibilities and Respective Capabilities (CBDR-RC). Exemptions from the CBAM should be considered prudently.

At a time when the formation of economic blocs is feared, Japan should promote talks with other Indo-Pacific countries to act as a bridge to prevent any new conflict and fragmentation of the world from deepening. Hopes are placed on rules-based Japan's contributions. When Japan designs its carbon border adjustment system, the Hillman (2013) approach, which combines a carbon tax in the form of indirect tax with border adjustment measures including rebates on exports, may become an option.

Notes

1) Marcu, A., M. Mehling and A. Cosbey (2020), "USA-EU Town Hall on Border Carbon Adjustment: An Update on Developments in the EU," European Roundtable on Climate Change and Sustainable Transition.

2) Article 27 of the EU Directive 2003/87/EC, the European Commission's guidance, etc. indicate that the EU members can exempt installations that emit 25,000t-CO_2/year or less and consume 35MW or less and are required to address verifier's recommendations of improvements for such installations. Brock, J., Bonifazi, E., Thorpe, C., Morgan-Price, S. and Kaar, A. (2019), "Preparation for the implementation of the EU ETS provisions for small installations, Best Practice Guidance," CLIMA-FWC-001/FRA/2015/0014.

3) European Court of Auditors (2020), "Special Report 18/2020 The EU's Emissions Trading System: free allocation of allowances needed better targeting."

4) Estimated by the author from European Environment Agency, European Union Transaction Log (EUTL)

5) European Commission (2021), "Proposal for a REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL establishing a carbon border adjustment mechanism," COM/2021/564 final.

6) Details about exporters are explained by Miki Yanagi, Soichi Morimoto, Hiroko Nakamura (2021), "The Carbon Border Adjustment Mechanism: Collaboration or Confrontation?" IEEJ 438th Forum on Research Works. As of 2019, iron and steel exporters to the EU (including the United Kingdom) included Russia, Turkey, Ukraine and China. https://eneken.ieej.or.jp/data/9943.pdf

7) Hillman, J.A. (2013), "Changing Climate for Carbon Taxes: Who's Afraid of the WTO?" Climate & Energy Policy Paper Series, Georgetown University Law Center.

8) The WTO's Agreement on Subsidies and Countervailing Measures (ASCM) defines "indirect taxes" as "sales, excise, turnover, value added, franchise, stamp, transfer, inventory and equipment taxes, border taxes, and all taxes other than direct taxes and import charges.", Hillman, J.A. (2013), "Changing Climate for Carbon Taxes: Who's Afraid of the WTO?" Climate & Energy Policy Paper Series, Georgetown University Law Center, Footnote 13.

9) Mehling, M., H. Van Asselt, K. Das, S. Droege and C. Verkuijl (2019), "Designing Border Carbon Adjustments for Enhanced Climate Action," American Journal of International Law, 113(3), 433 - 481.

10) "The chapeau Article XX of the GATT (instead of each item of the article) was interpreted in reference to policy purposes." Details are explained in Tsuyoshi Kawase (2007), "Measures related to Brazil's retreaded tire imports," in 'Study on FY2007 WTO Panel/ Appellate Body Report,' Ministry of Economy, Trade and Industry.

11) Details are explained by the Ministry of Economy, Trade and Industry (2022), "2022 Review Report on Unfair Trade Practices," in Overview of WTO Agreements, Column, Trade and Environment: Carbon Border Adjustments' Outline and Compatibility with WTO Rules. (In Japanese)

12) Bacchus. J. (2021), "Legal Issues with the European Carbon Border Adjustment Mechanism," BRIEFING PAPER No. 125, CATO Institute.

EU Agreed on World's First CBAM – Summary Bulletin
Phasing out free allowance to steel and other sectors by 2034 in transition to the Carbon Border Adjustment Mechanism (CBAM) Tensions of Potential Green Trade War

Miki Yanagi* Soichi Morimoto*

- The EU will impose reporting obligation of embedded emission on imported goods from October 2023, and will start charging through Carbon Border Adjustment Mechanism (CBAM) certificate which reflects EU-ETS auctions price from 2026 by the agreed regulation.
- Hydrogen added to steel and other material goods including ammonia as imported goods subject to CBAM. Organic Chemical goods proposed by the European Parliament are deleted from the CBAM goods list with reservations, weakening the impact on the United States, which has large exports to the EU.
- The EU will phase out free allowances of EU-ETS (Emission Trading Systems) while phasing in the CBAM from 2026 to 2034.

This paper dealt with "pivotal agreement" which was mainly written by authors in December 2022 using the press release. On 10 May 2023, the co-legislators (the Council and the European Parliament) signed the CBAM Regulation. The regulation then officially entered into force the day following its publication in the Official Journal of the EU on 16 May 2023. Thus, the author partially rewrites this paper by using * mark, which reflects the published regulation in the Official Journal of the EU.

1. Background and Objectives

The European Union has considered the CBAM over the past three years since the inauguration of European Commission (EC) President Ursula von der Leyen under plans to legislate the CBAM by the end of 2022.

In July 2021, the EC, the EU's executive arm, presented a proposal on the CBAM.[1] By June 2022, the European Parliament and The Council proposed their respective amendment to the proposal. After a trialogue among the EC, the European Parliament and the Council on these proposals, the European Parliament and the Council reached this pivotal agreement on December 18, 2022. The political agreement was published through their respective press releases (European Parliament 2022c, 2022d, Council of the Europe Union 2022b).

This paper aims to summarize the CBAM as a bulletin. Therefore, it must be noted that when specific CBAM acts (Implementing Act and Delegated Act, both to be decided before October 2023) are published, interpretation may change.

2. What is the CBAM?

The CBAM is designed to adjust carbon pricing costs regarding imports at the border. CBAM certificates reflecting EU-ETS prices will be used to adjust gaps between carbon prices paid in third countries of origin for imports and EU-ETS prices. The unprecedented mechanism is feared to be incompatible with most-favored-nation treatment and other basic principles under the General Agreement on Tariffs and Trade (GATT). If so, a challenge may be whether the CBAM could be justified under GATT Article 20 for general exceptions.[2]

The EU has considered the "Fit for 55" policy package to achieve a goal of cutting greenhouse gas emissions by 55% or more from 1990 by 2030 under its Nationally Determined Contributions for the Paris Agreement. As part of the policy

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[1] For details of the EC's CBAM proposal, see Yanagi, Morimoto and Nakamura (2021).

[2] Yanagi (2022) discussed issues regarding the CBAM's compatibility with World Trade Organization (WTO) rules, based on earlier studies.

package, the EU has considered terminating the free allowance of EU-ETS designed to counter carbon leakage under the EU-ETS and introducing the CBAM as a substitute. As the CBAM has been viewed as indispensable for avoiding adverse effects on industrial competitiveness when free allowances are terminated in EU-ETS.

Carbon pricing will be levied at the border on imports from countries where climate change countermeasures are insufficient. Additionally, carbon costs for exports may be refunded as a rebate at the border. Whether the unprecedented BCAM's compatibility with WTO rules depends on a specific design of the border carbon adjustment.

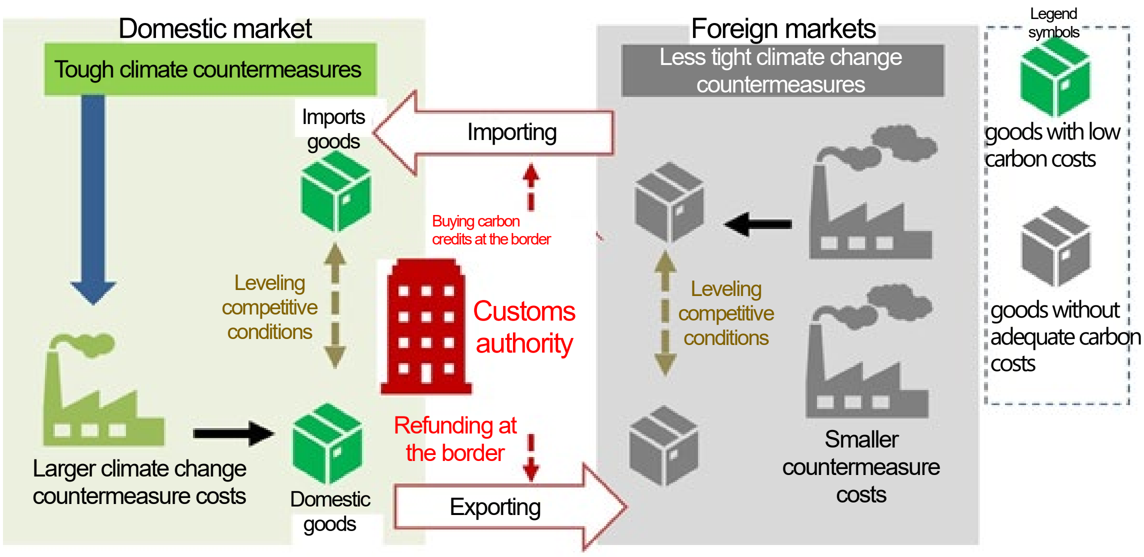


Fig. 1 Concept of carbon border adjustment

Source: Prepared by the authors

3. Key points of the CBAM regulation

The pivotal agreement reached in December calls for raising a cut in emissions between 1990 and 2030 to 62% from 43% for the EU-ETS covered sectors. Free allowance will be terminated for iron & steel, cement, aluminum, fertilizer, hydrogen and other sectors in 2034, with the CBAM introduced as a tool for preventing carbon leakage. Key points of CBAM regulation are as follows:

- ✓ **Commencement of requirements: A requirement for reporting Green House Gases (GHG) emissions from imported goods listed will commence in October 2023. A requirement for paying for CBAM certificates for imported goods in each sector will commence in 2026, representing an effective levy[3].**
- ✓ **Termination of free allowance and transition to the CBAM: Free allowance will be phased out by 2034, with the CBAM being phased in at that pace. The transition to the CBAM will be slow between 2026 and 2030 before the reduction of free allowance accelerates (Fig. 2).**

Marcu et al. (2020) indicated major components of the CBAM design. We compiled the CBAM agreement between the European Parliament and the Council into Table 1 according to the components. Reviews are noted below the Table.*

[3] The European Parliament press release indicates the simplification of the 2023 reporting requirement, saying "a simplified system would be in force." As for the reporting requirement, specific rules to be published in the future will have to be checked.

Table 1 Summary of CBAM design components under the trialogue agreement (December 2022)

	CBAM components:
1)	Scope of trade subject to adjustment: Limited to imports However, the EC will review carbon leakage risks regarding exports(rebate) before * 1 January 2028, and propose a WTO-compatible proposal as necessary.
2)	Policy subject to adjustment: EU-ETS
3)	Countries subject to levies on imported goods: In the absence of provisions for exceptions, all non-EU countries are seen as subject to the CBAM. There is no exception for Least Developed Countries (LDCs).
4)	Targeted Goods: Iron & steel, cement, aluminum, fertilizer (*including ammonia), electricity, hydrogen, some precursors,[4] and some downstream steel products, such as screws and bolts
	While the EC proposal cited "iron & steel, cement, aluminum, fertilizers and electricity" as target sectors, the European Parliament proposal included "iron & steel, cement, aluminum, fertilizers, electricity, hydrogen, ammonia, polymers (plastics, etc.) and organic chemicals." The regulation excluded organic chemicals*.
5)	Scope of product emissions: direct emissions (*Steel and aluminum, Hydrogen) and indirect emissions (*cement, fertilizer, electricity) under certain conditions (*Need to check Implementation Act or Delegated Act to see if on-site power generation is included)
6)	How to convert installations emissions into goods emissions: Unknown
7)	Emissions for adjustment: *Actual emissions of goods. If that data is not available, use the benchmark (bottom X% for EU-ETS) (* X% will be decided later).
8)	Prices for application: the price of the CBAM certificate is linked to the EU-ETS weekly average prices(*).
9)	How to use government revenue: New own resource for EU, The EC proposal called for such revenue into the EU's exclusive financial resources, which is estimated€ 2.1 billion. by the European committee. As for LDCs' supports, the Union should continue to support low and middle-income third countries through the Union budget, especially LDCs,

Source: Prepared by the authors according to the compilation by March et al. (2020)

Note: Countries that export target goods to the EU are described at the end of this paper.

*** Review: <u>Before the end of the transitional period</u>,** the EC shall present a report__subjecting organic chemicals and other goods including polymers to the CBAM. The EC shall assess how to monitor indirect emissions, embedded emissions in the transport of the goods, and the expansion of the CBAM's coverage to include **precursor** of listed goods.
The criteria to be used to identify goods to be included in the subject list, which are also contained in the report. At least one year before the end of the transitional period, the Commission shall present a report to the European Parliament and to the Council that identifies products further down the value chain of the goods. (*)
*** An assessment:** Before 1 January 2028, as well as every two years thereafter, the EC shall conduct an assessment of the CBAM's impact on carbon leakage, including in relation to exports, the sectors covered, international trade, including resource

[4] The Council's press release puts "precursors" just after "iron and steel," leading some people to interpret "precursors" as goods related to iron and steel, according to some media reports. However, it is not certain whether the interpretation is true or not.

shuffling, the practice of circumvention, and LDCs.[5] (*)

* The EC shall assess the goal of subjecting all EU-ETS sectors to the CBAM by 2030. (*)

It should be noted that both the European Parliament and the Council, in full compatibility of WTO rules, have said that CBAM will only apply to the proportion of emissions that do not benefit from EU-ETS free allowances. In addition, while the EU-ETS is an installation-based regulation, CBAM requires specifying the amount of emissions for each good, but it is considered extremely difficult to measure the amount of emissions in goods units. According to media reports, consideration of the bill on the EU's own resources may be considered in 2023.

4. Attention-attracting points

The following summarizes political issues related to the business community.

1) Reducing free allowance and moderate transition to the CBAM

How to reduce EU-ETS free allowance and transition from the EU-ETS to the CBAM was a key political issue. The EC proposed that free allowance be reduced at a certain pace from 2026. The agreement between the European Parliament and **The Council** calls for a moderate cut in free allowance at the beginning of the CBAM in an apparent bid to allow the business community to secure several years for the transition.

EC Proposal (July 2021)[6]

2026: 0%, 2027: 10%, 2028:20%, 2029: 30%, 2030: 40%, 2031: 50%, 2032:60%,
2033: 70%, 2034: 80%, 2035: 90%, 2036:100%

↓

European Parliament amendments (June 2022)

2026: 0%, 2027: 7%, 2028: 16%, 2029: 31%, 2030: 50%, 2031: 75%, 2032:100%

Council amendments (June 2022)

2026: 5%,2027:10%, 2028: 15%, 2029: 22.5%, 2030: 30%, 2031: 40%, 2032:50%, 2032:70%, 2032:90%, 2032:100%

↓

Trialogue agreement (December 2022)

2026: 2.5%, 2027: 5%, 2028: 10%, 2029: 22.5%, 2030: 48.5%, 2031: 61%, 2032: 73.5%,
2033: 86%, 2034: 100%

[5] According to our analysis, the CBAM is feared to affect aluminum product imports from Mozambique.
[6] When the source indicates a free emission allowance reduction rate, we interpret the rate as a CBAM share.

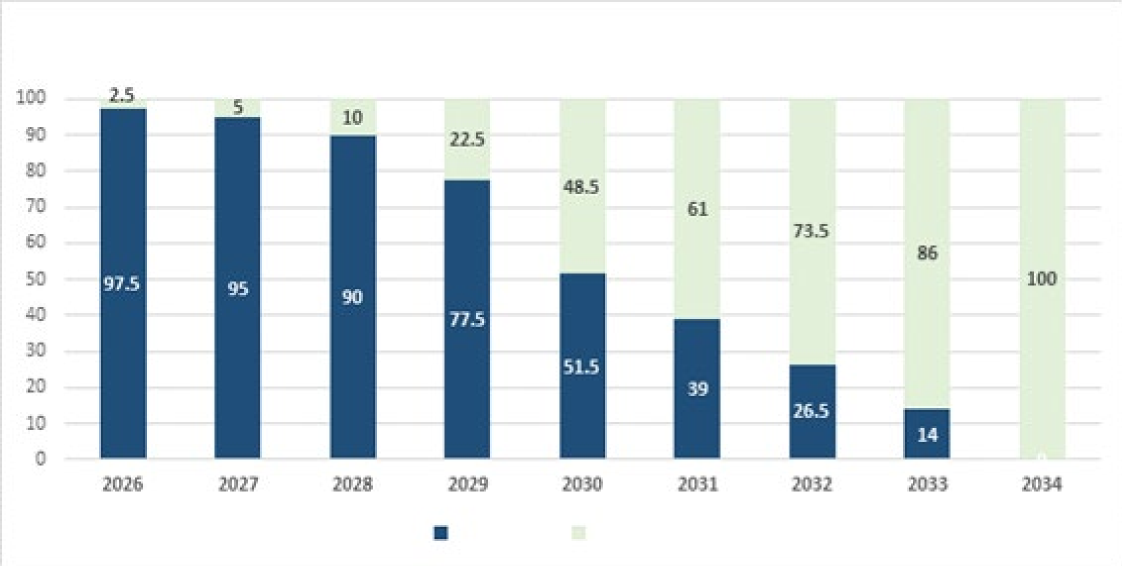


Fig. 2 Introducing the CBAM introduction and phasing out free emission allowances

2) Giving up on export rebates as a consideration to export industries

EU industries have concerns that export competitiveness will decline if free allowance of EU-ETS is declined and CBAM is limited to charging imports amid rising carbon pricing.[7]

The European Parliament amendments included an "export rebate" option to leave free allowance for goods of exports, taking the business community's request into account. The Council and the EC rejected the option, which they interpreted as running counter to WTO rules. The trialogue agreement notes that the EC would assess carbon leakage risks regarding exports by 2025 and propose a WTO-compatible bill as necessary.

The trialogue agreement includes no export refund option but calls for increasing the Innovation Fund from the current 450 million allowances to 575 million allowances to support the business community's acceleration of decarbonization. The fund is financed by EU-ETS auction revenue. "In addition, an estimated 47.5 million allowances will be used to raise new and additional financing to address any risk of export-related carbon leakage," according to the agreement. How to use revenue from allowance sales is not specified.[8] Given the trialogue history, using such revenue for export refunds could be difficult as it may run counter to GATT and the Agreement on Subsidies and Countervailing Measures.[9]

Peter Liese, a center-right member of the European Parliament elected from Germany, said that the following five points were agreed on:

- There is a legal guarantee that the reduction of free allowance will be suspended if problems arise with the enforcement of the CBAM.
- The EU member countries appropriate an additional €3.5 billion from EU-ETS revenue for supporting exporters' transition to carbon neutrality.
- The EU member countries may use additional funds from state revenue for supporting the industry sector.
- Special calls of the Innovation Fund will be established for relevant industries
  (special calls may top €50 billion by 2030).
- There is a revision clause for introducing additional measures if the CBAM is bogged down.

[7] The European Steel Association, European Aluminum, the European Cement Association, Fertilizers Europe, etc. "CBAM sectors statement on ETS and CBAM Trialogues," November 7, 2022
[8] The diversion of free emission allowances and the composition of the fund are left vague.
[9] METI (2022) details export refund's potential to run counter to the WTO agreement and the Agreement on Subsidies and Countervailing Measures.

5. Summary (in place of conclusion)

The key point of the trialogue CBAM agreement is that the EU will phase out the free allowance of EU-ETS for steel and other hard to abate sectors while phasing in the CBAM. As for details, attention should be paid to two points – (1) organic chemicals goods imported mainly from the United States were out of the list and (2) no export rebate was endorsed.

As for the first attention-attracting point, the exemption was designed to avoid a trade dispute with the United States. As for the second one, the export refund has the potential to run counter to WTO rules (ASCM). Both points are related to a potential green trade war. Organic chemical imports and export refunds could be covered by the CBAM through the EC's future assessment. In this sense, the seeds of a trade war are still left. As for iron and steel, cement, fertilizer (including ammonia), hydrogen and other goods subjected to the CBAM, trade disputes could emerge with China and other Global South countries. India may plan to challenge CBAM.　For exporters of the CBAM-covered goods to the EU, see Fig. 3.

Reportedly, U.S. Trade Representative Katherine Tai proposed a methodology for adjusting carbon contents based on carbon intensity from iron and steel goods during negotiations with the EU on tariffs under Article 232 of the U.S. Trade Expansion Act, exploring U.S.-EU cooperation.[10] On the other hand, the European business community is alert to the U.S. Inflation Reduction Act,[11] which provides tax credit incentives for decarbonization technologies that satisfy country of origin requirements. The EU iron and steel sector has claimed that the EU should assess the U.S. act's impact on the European business community and discuss appropriate measures to level the playing field, indicating a seed of U.S.-EU confrontation (EUROPER 2022).

Even at a time when the division of the world deepens, Japan should address the rules-based approach for CBAM. In Japan, the Green Transformation (GX) League is now considering an Emissions Trading System and carbon surcharge.[12] When a carbon border adjustment measure is required due to carbon price hikes, Japan should learn from EU experiences and address the measure, which is in the form of the indirect carbon tax. In a manner compatible with WTO/GATT rules to avoid any green trade war seed.

Impacts of rulemaking for hydrogen should be watched

Hydrogen has been subject to the CBAM. The EC seeks to produce 10 million tons of hydrogen from renewable energy (hereinafter referred to as green hydrogen) and import 10 million tons of green hydrogen under the REPower EU Plan announced in May 2022 to phase out the EU's dependence on Russian fossil fuels.

When the CBAM is implemented for imported hydrogen, emissions from imported hydrogen may have to be monitored. The EU's method to monitor emissions may become an international de facto standard.

Regarding hydrogen, the EU taxonomy has established a quantitative standard to certify a substantial contribution to climate change mitigation. The EC is trying to define green hydrogen. The EU has thus activated rulemaking regarding hydrogen.

In May 2022, the EC published a draft proposal on the definition of green hydrogen for the transportation sector,[13] setting forth a plan to certify green hydrogen, which satisfies the requirement that green water electrolysis operates when renewable electricity is integrated into the grid.[14] As the business community complained that an additional requirement in the draft proposal was too strict, the time requirement for renewable power generation was weakened, according to reports up to January 2023.

If the EU's rulemaking regarding hydrogen produces global de facto standards, it may exert a great impact on other

[10] A U.S.-EU agreement in October 2021 called for a global arrangement to address global overcapacity in the steel sector while reducing trade in steel goods that emit massive amounts of carbon (October 2021).

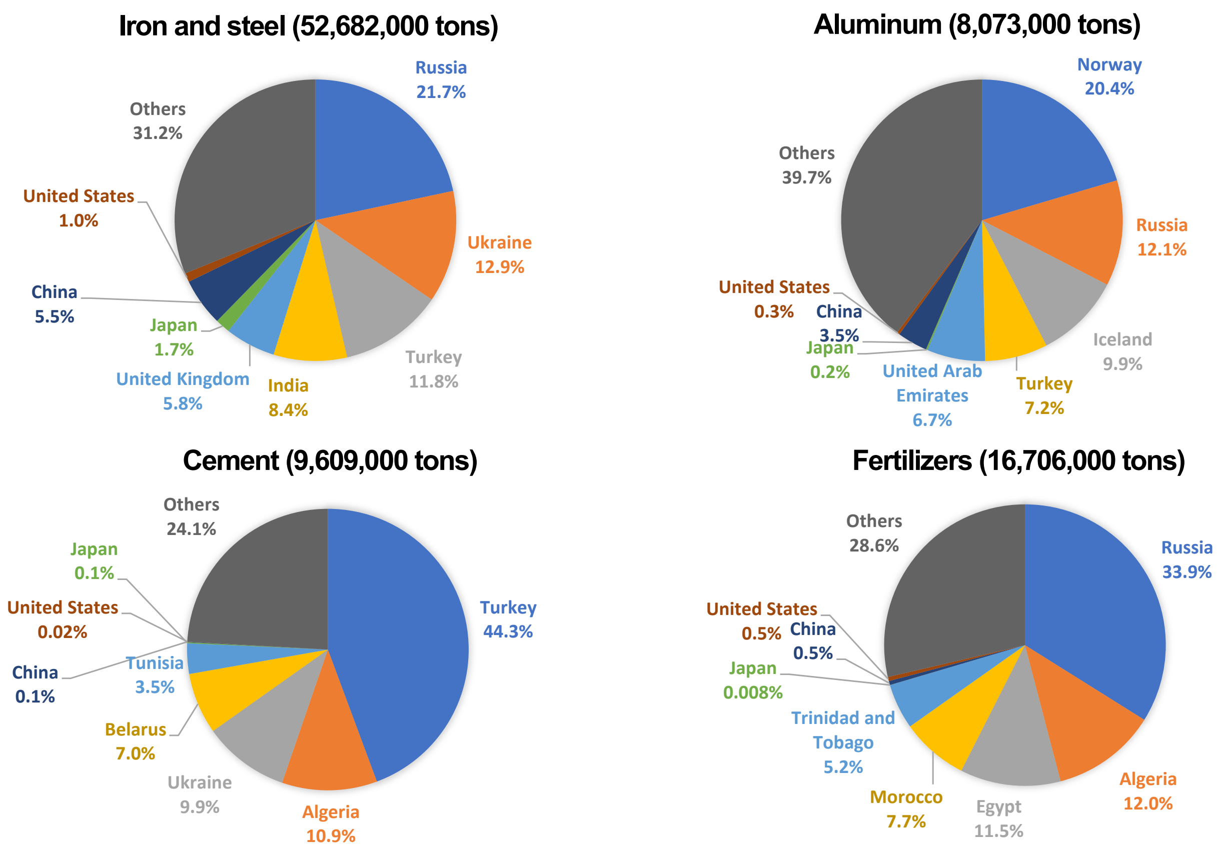
[11] Ueno (2022) details the Inflation Reduction Act and country of origin requirements. For instance, a tax credit worth $3,750 is provided for a clean automobile with a battery for which a certain percentage of key minerals are extracted or processed in the United States or any country that has a free trade agreement with the United States or reused in North America (September 2022).

[12] In Japan, Green Transformation (GX) related legislation was passed and enacted by the 211 Diet on May 2023, which deal with Japanese Emission Trading Systems. Studies are underway to make the ETS operational in FY2026. A phased introduction of " auctions" for power utilities is being considered starting in FY2033 (This foot note is added by author in Mat2023).

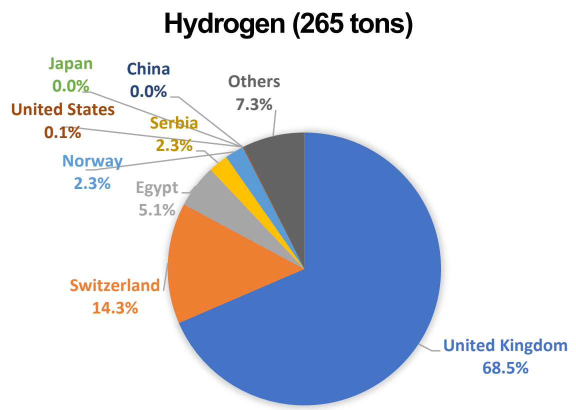
[13] European Commission (2022a). This proposal is planned to be implemented from January 2027.

[14] IEEJ (2022)

countries, which are trying to expand hydrogen imports. In this sense, the EU rulemaking should be watched closely.



Source: The data above were browsed on January 10, 2023.



Source: The data above were browsed on January 10, 2023.
Note: As for hydrogen, the HS6-digit (280410) data were aggregated.

Fig. 3 Breakdown of imports into the EU by the exporter for 5 CBAM-covered sectors (in volume, 2021)

Source: Based on European Commission (2021a), the authors aggregated "Eurostat, 'Extra-EU trade since 2000 by mode of transport, by HS2-4-6.'"

Note: European Commission (2021a) covers the CN4-8-digit product list. The above chart represents HS6-digit aggregation (deltas for some 8-digit goods are minor). For each sector, the aggregation covered the five largest exporters to the EU, as well as Japan, the United States, China and other countries. Hydrogen imports from Japan and China are zero. Data are as of the day for browsing and may be revised retroactively.

Acknowledgment
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The Benefits and Issues of the “Stop-Count” Measure on Existing Japanese Nuclear Reactors

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1. Introduction

Amid indications of the importance of nuclear power from the viewpoint of climate policy, electricity supply stability and energy security, major developments in the debate over nuclear power policy in Japan were seen in the second half of 2022. In particular, at the meeting of Ministry of Economy, Trade and Industry’s Nuclear Energy Subcommittee on December 8, the *Agenda for the future direction and realization of nuclear power policy (draft)* was presented, with basic principles laid out for handling various challenges in nuclear power policy. These principles, which are to be included in the basic policy of the GX (Green Transformation) Implementation Council[1] chaired by the Prime Minister, were approved by the members of the subcommittee.

Of the measures in the draft agenda above, one of the most likely to have a specific impact in the relatively near future is seen to be the implementation of a new rule related to the operating life of existing reactors. In this paper, were the draft agenda to be approved, we estimate the potential impacts on operating life extensions for existing reactors and endeavor to identify the challenges that might arise.

2. Debate over operating life extensions

Under the current rules that were established in the wake of the Fukushima Daiichi Nuclear Power Plant accident (hereafter “Fukushima Daichi accident”), all nuclear reactors were permitted to operate for 20 further years, once only and on condition of passing a prescribed safety inspection, based on a basic operating life of 40 years from the date of their entry into operation[2]. Nevertheless, Japan’s nuclear power plants, which all suspended operations after the Fukushima Daichi accident, were required to pass the safety inspection of the Nuclear Regulation Authority. Due to the prolonged period of these inspections, 23 of 33 existing reactors have not yet been able to restart operations as of December 2022, more than 10 years on from the accident. Moreover, some plants that have restarted have been forced to suspend operations due to failure to meet deadlines for new antiterrorism specialized safety facilities required to meet the regulations, and in many parts of Japan lawsuits from local communities have demanded the suspension of reactor operations. In some cases, courts have handed down rulings stopping plant operations.

As a result of such factors, these nuclear plants are nearing the end of their lives without generating a single watt of electricity as they reach the operating time limits (40 years or 60 years). This situation not only limits our ability to take advantage of the stable power supply and zero-emission performance of nuclear power, it could also have a serious impact on the generation portfolios of power companies that own nuclear power plants. There are also concerns that the highly uncertain business environment could discourage new investment in nuclear power. Therefore, the recently announced draft agenda includes a proposal to deduct the period of suspension due to inspections or other reasons from the prescribed operating life and extend the operating life by that amount of time (hereinafter referred to as "stop-count"). The impact of implementing this proposal will be estimated in the next section.

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[1] GX Implementation Council, *Basic Policy of GX (Draft)*, December 22, 2022.

[2] See Kimura (2021) shows that these rules had had the possibility for revision from their beginning （https://eneken.ieej.or.jp/data/10047.pdf）.

3. The impact of the stop-count

The rules in the draft agenda related to the stop-count are as follows[3].

A: Shutdown periods resulting from regulatory changes (safety rules, etc.) made after the Great East Japan Earthquake disaster (including inspection and preparation periods following changes in circumstances)

B: Shutdown periods resulting from administrative orders, advice or guidance, etc. after the Great East Japan Earthquake disaster (excluding suspensions due to inappropriate conduct by the plant operator)

C: Shutdown periods resulting from provisional court orders or other reasons unforeseen by the plant operator after the Great East Japan Earthquake disaster (limited to those cases where remedy is gained in higher court)

Based on these rules, the authors set certain conditions and estimated the stop-count period[4], with the results shown in Table 1. The total stop-count period for all 33 reactors is 357.3 reactor-years, at an average of 10.8 years for each reactor. If it had been possible to operate normally[5] during this period, the power output of those reactors would have been about 2,200 TWh (total power generation in Japan 2021 was about 1,000 TWh[6]). At a unit price of 13.5 yen/kWh[7], the average wholesale electricity market price in FY2021, the value of the power (the product of the amount of power and the unit price) lost due to the shutdown totaled about 30 trillion yen. Of course, since the price of electricity constantly changes depending on the situation, this amount is only a rough indication, but this is considered to be the total amount that can be expected to be obtained by stop-count and would be a considerable incentive for power companies. In addition, if all of this power generation replaced LNG thermal power generation (combined cycle), carbon dioxide (CO_2) emissions have been reduced by 997 million tons[8]. This is higher than total Japan's CO_2 emissions from energy sources (967 million tons[9]) in FY2020.

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[3] Agency for Natural Resources and Energy. *Agenda for the future direction and realization of nuclear power policy (draft)*, 35th meeting of Nuclear Energy Subcommittee, Electricity and Gas Industry Committee, Advisory Committee for Natural Resources and Energy, December 8, 2022.

[4] The authors set the main conditions as follows:

- In addition to the period from shutdown to restart after the Fukushima Daiichi accident, the calculation includes any suspensions required for completion of specialized safety facilities and to abide by court rulings.
- For plants that had been out of service prior to the Fukushima Daiichi accident, the shutdown date is set as March 11, 2011.
- For plants that have not restarted as of the time of writing (April 2023), for the purposes of calculations in this paper, it is assumed that their restart date shall be December 31, 2023 (because it is unlikely that they will be restarted within this year judging from their current state). However, the dates of expected conclusion of regular inspections are shown for Reactors 1 and 2 of KEPCO Takahama Power Station, therefore this information is included in the calculation (applying the condition below at the same time, it is assumed that restart will occur one month after the dates of expected conclusion of the regular inspection).
- For plants that have already restarted operations, the restart date is defined as that of resumption of commercial operation. This is the same as for those plants coming back from suspensions related to specialized safety facilities or court rulings. For plants that did not have a specified commercial operation restart date as of the time of writing, the date of resumption of commercial operation is defined as one month after the restart of power generation.

[5] At a capacity utilization rate of 70%. This was the track record of operation in Japan before the Fukushima Daiichi accident.

[6] From IEA statistics.

[7] Agency for Natural Resources and Energy. *Recent trends in the wholesale electricity market*, 49th meeting of the Electricity and Gas Policy Subcommittee, Electricity and Gas Industry Committee, Advisory Committee for Natural Resources and Energy, May 17, 2022.

[8] CO_2 emission factors by power generation source are from Japan Atomic Energy Relations Organization, *Graphical Flip-chart of Nuclear & Energy Related Topics*.

[9] From the website of the Greenhouse Gas Inventory Office of Japan.

Table 1 Stop-count periods for each plant

Restarted & Expected			Restart not yet determined					
Plant name	Installed capacity (GW)	Shutdown period (years)	Plant name	Installed capacity (GW)	Shutdown period (years)	Plant name	Installed capacity (GW)	Shutdown period (years)
Mihama 3	0.83	11.1	Tokai-II	1.10	12.8	Kashiwazaki-Kariwa 5	1.10	11.9
Takahama 1	0.83	12.3	Tsuruga 2	1.16	12.7	Kashiwazaki-Kariwa 6	1.36	11.8
Takahama 2	0.83	11.7	Tomari 1	0.58	12.7	Kashiwazaki-Kariwa 7	1.36	12.4
Takahama 3	0.87	6.6	Tomari 2	0.58	12.4	Hamaoka 3	1.10	12.8
Takahama 4	0.87	6.5	Tomari 3	0.91	11.7	Hamaoka 4	1.14	12.6
Ohi 3	1.18	6.4	Onagawa 2	0.83	12.8	Hamaoka 5	1.38	12.6
Ohi 4	1.18	5.8	Onagawa 3	0.83	12.8	Shika 1	0.54	12.8
Ikata 3	0.89	8.3	Higashidori 1	1.10	12.8	Shika 2	1.21	12.8
Genkai 3	1.18	8.2	Kashiwazaki-Kariwa 1	1.10	12.4	Shimane 2	0.82	11.9
Genkai 4	1.18	7.1	Kashiwazaki-Kariwa 2	1.10	12.8			
Sendai 1	0.89	5.1	Kashiwazaki-Kariwa 3	1.10	12.8			
Sendai 2	0.89	4.9	Kashiwazaki-Kariwa 4	1.10	12.8			

Source: Calculated by the authors from Agency for Natural Resources and Energy documents, among others (installed capacity from Japan Atomic Industrial Forum (2022)[10])

4. Discussion

As seen in the previous section, stop-count is a measure that could contribute to electricity supply to Japan and carbon emission reduction and be a considerable incentive for power companies, but there are several considerations that would need to be taken into account in practice. The first are the issues involved in specific system design, such as how to calculate the number of days to be deducted. This paper raises broadly three main points here. We would also like to point out the respective implications of the adoption of stop-count for plants that have already been restarted, that have not yet restarted, and that are to be decommissioned.

4-1. Methodology for calculating shutdown period

(1) Start date of the shutdown period to be deducted

In our study, the start date of the shutdown period for the nine plants that were already stopped prior to the Fukushima Daiichi accident due to regular inspections or equipment issues is set as March 11, 2011. For example, Kashiwazaki-Kariwa Nos. 3 and 4 were already in long-term outage at the time of the Fukushima Daiichi accident due to the 2007 Chūetsu offshore earthquake. In terms of these plants, further consideration is likely to be needed in future as to whether their full shutdown period from March 11 should be seen as due to the Fukushima Daiichi accident.

(2) End date of the shutdown period to be deducted

Since the official start of operation is generally considered to be the start of commercial operation, this paper sets the end date of the shutdown period (that is, the date of operation resuming) as the date of resumption of commercial operation. However, if the date is set as the day the reactor is restarted or the date of power generation resumes, the shutdown period subject to the stop-count is inevitably shortened. Since neutron irradiation embrittlement of a nuclear reactor is caused by the operation of the reactor, if we were to emphasize this point, we might consider the end date of the shutdown period to be the day of reactor restart. However, it should be noted that this measure is intended to stipulate the period of use of nuclear reactors from the perspective of nuclear energy policy. Measures to evaluate the deterioration of equipment from a scientific point of view are to be implemented separately by the Nuclear Regulation Authority (see below).

(3) Shutdowns due to regular inspections from prior to the completion deadline for specialized safety facilities

Takahama No. 3 and Genkai No. 3 were shut down for regular inspections about seven months earlier than the actual completion deadline. In this study, it is deemed that the work necessary for the construction of specialized safety facilities

10 Japan Atomic Industrial Forum, *World Nuclear Power Plants 2022*, 2022.

was underway even before the deadline (that is, the shutdown period necessary for the construction of the specialized safety facility), and these are also included as stop-counts. However, in the case of Takahama No. 3, which was scheduled to resume operations ahead of the deadline for the specialized safety facility, the regular inspection was postponed due to damage to the steam generator heat transfer tube, and as a result, the deadline for its specialized safety facility passed in August 2020. In addition, Genkai No. 3 was originally scheduled to complete its specialized safety facility by a deadline of August 2022, but it was reported that the construction period was extended due to a fire at the construction site and the impact of COVID-19[11]. The reactor resumed operation in December 2022. If rigorous calculations are to be made in these cases, it is necessary to clarify how many days of the shutdown period are due to work related to specialized safety facilities. In the case of Genkai No. 3, it may be a point of issue whether the cause of the delay is attributable to the operator.

Given that operators are responsible for failure to meet deadlines in completing their specialized safety facilities, it might also be reasonable not to include specialized safety facility issues in the stop-count.

4-2. Implications of stop-count for plants that have already been restarted, that have not yet restarted, and that are to be decommissioned

Defining the actual age of a plant as the period from the start date of its commercial operation to December 31, 2023 (see footnote 4), the age after the application of the stop-count can be obtained by deducting from that age the number of years of shutdown as calculated in Table 1. The actual age of each plant and the age after applying stop-count are summarized in Fig. 1. As shown in the figure, unrestarted plants tend to be "young" plants because more years are deducted from their age than plants that have been restarted or are expected to be restarted. Therefore, although it is currently unclear whether the final operating life of each plant will be 40 years or 60 years, the remaining operating life will clearly be longer for the unrestarted plants. Of course, according to this method, there is no significant difference between restarted plants and unrestarted plants in terms of total operating time. On the other hand, it should be noted that under the stop-count measure, the remaining life will be shorter for plants that are restarted earlier, are equipped with superior technological capabilities, and are in compliance with the new regulatory standards. The current stop-count proposal can be seen as a "relief measure for plants that had to shut down for a long time due to external factors that could not have been foreseen by the operator," but it may be necessary to acknowledge the achievements of the plants that have carved a path to restart with few (or no) precedents and the importance of the efforts they made to get there.

Moreover, stop-count may have economic profit for remaining plants, but of course it is not valid for those reactors permanently closed and already scheduled for decommissioning. Some decommissioning decisions made since the Fukushima Daiichi accident have been reached by comparing the forecast costs involved in restarting with the forecast profits from their remaining operating period after achieving restart[12]. If stop-count had been in place then, it may have had an influence on decisions about the survival of plants.

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[11] *Saga Shimbun*, December 6, 2022.

[12] For example, the reason stated for the decision to decommission Ikata No. 2 taken in March 2018 by Shikoku Electric Power was, “Taking into account all of the factors such as operating period from restart and output, we have decided to decommission it” (Shikoku Electric Power press release, March 17, 2018).

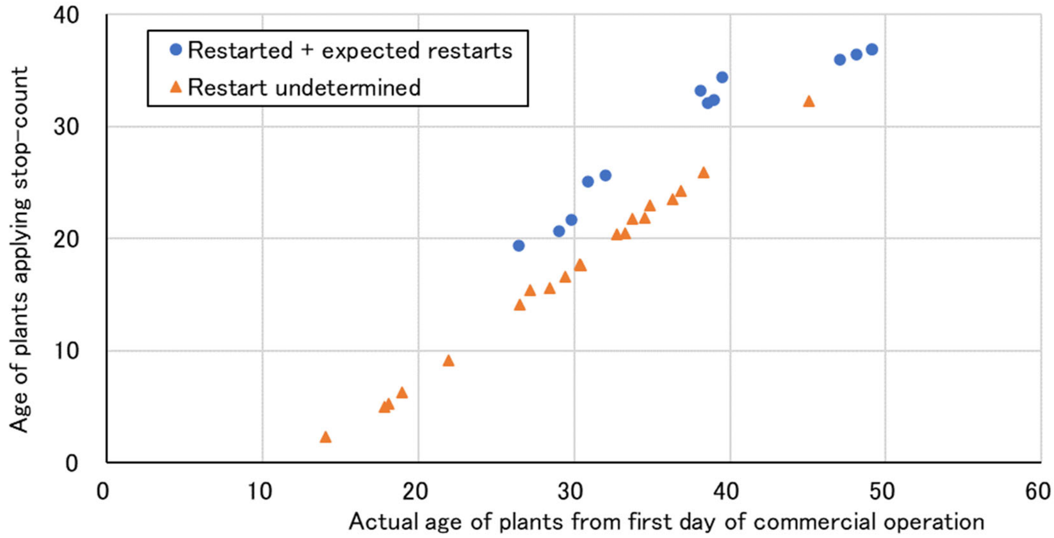

Fig. 1 Actual age of plants and age after the application of stop-count

Source: Calculated by the authors from Agency for Natural Resources and Energy documents

5. Conclusion

In this study, shutdown periods that might be subject to stop-count measures based on the content of the *Agenda for the future direction and realization of nuclear power policy (draft)* were calculated, the impact demonstrated and potential issues arising in implementation raised. As a measure to promote the utilization of existing reactors, stop-count would be a considerable incentive for nuclear power companies, but at this time there are a number of matters to consider. If the measure were implemented, it would need to be given more detail in a logical, explicable form.

It must also be noted that some facilities age even during shutdown periods. The "stop-count" theory discussed in this paper is intended to define the period of use of nuclear reactors from the perspective of nuclear energy policy. It does not include the perspective of ensuring safety. In this regard, the Nuclear Regulation Authority has announced a policy of conducting inspections 30 years after the start of operation, with further inspections every 10 years thereafter as a new mechanism for periodically determining whether or not to continue operation of a reactor[13]. This policy was determined by the Authority and is under Diet deliberations at the same time as the stop-count measure as of the time of writing. If it does not pass the inspection by the Authority, it would not be possible to continue operation at that point, regardless of the operating life extension afforded by the stop-count[14]. It is important to grasp the impact of aging through such a check mechanism in the effective use of existing reactors over the long term.

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[13] Nuclear Regulation Authority Chair Scheduled Briefing paper, *Safety regulatory system related the aging of reactors (current and proposed)*, December 21, 2022.
Note that a mechanism to assess aging is already in place at 30 years after the start of operation, with further inspections every 10 years thereafter. This proposal brings together the decision on continuing operation and the aging assessment.

[14] Also considered by the Nuclear Energy Subcommittee was a proposal for government to not set a particular ceiling on operating period, so that continued operation could be decided by the Nuclear Regulation Authority from the viewpoint of safety (Agency for Natural Resources and Energy. *Matters for future consideration related to nuclear power policy*, 33rd meeting of Nuclear Energy Subcommittee, Electricity and Gas Industry Committee, Advisory Committee for Natural Resources and Energy, November 8, 2022).

Data deep dive

Household energy costs reach new high of 300 000 yen

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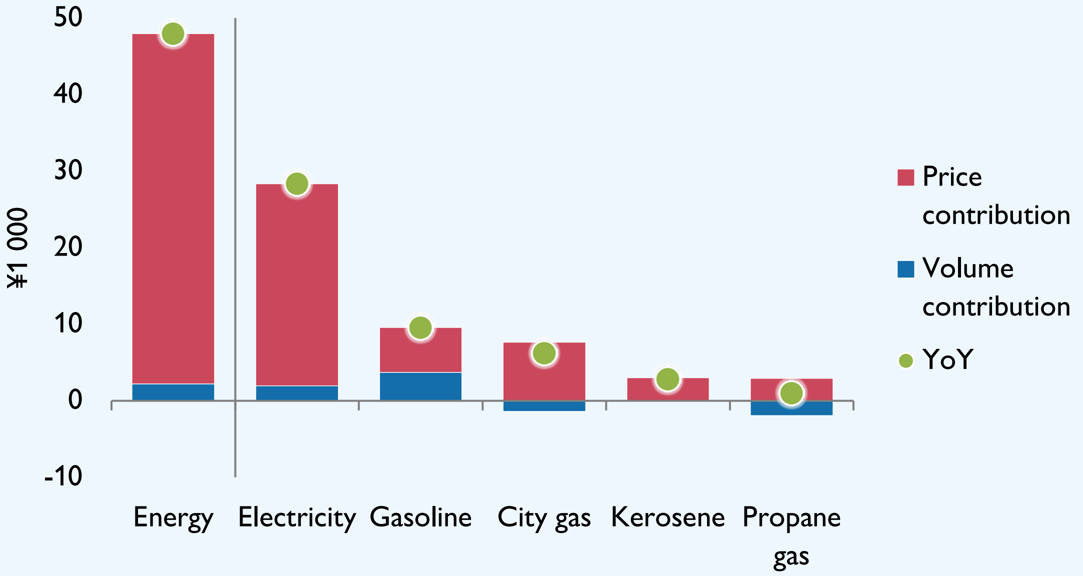
Summary

Household energy costs are ballooning and are expected to reach 300 000 yen a year in 2022, a level that would match or exceed the highest ever recorded. Electricity will reach a record high, gasoline will be at its highest in eight years and city gas in seven years.

The large year-on-year increase of ¥48 000, or 20%, is also a concern. Most of this was due to higher energy prices. In particular, the increase in electricity prices alone pushed up energy costs by ¥26 000, accounting for more than half of the increase.

Figure 1 | Decomposition of energy cost changes [2022, YoY]



In 2022, total consumption expenditures are also expected to increase. However, about half of the increase will come from higher spending on energy and food. Spending on necessities grew much faster than income because it was not caused by discretionary spending by households but by the rising prices of necessities.

Domestic crude oil prices remain high, although they have softened somewhat from their all-time highs. The main cause of the high prices, however, has now shifted from international market conditions to the weaker yen. As expectations of a slowdown in the pace of U.S. interest rate hikes spread, upward pressure on the dollar has weakened. However, the depreciation of the yen has been slower to correct than other currencies. This implies that Japan will likely continue to pay more than other countries when importing energy, which is generally traded internationally in dollars.

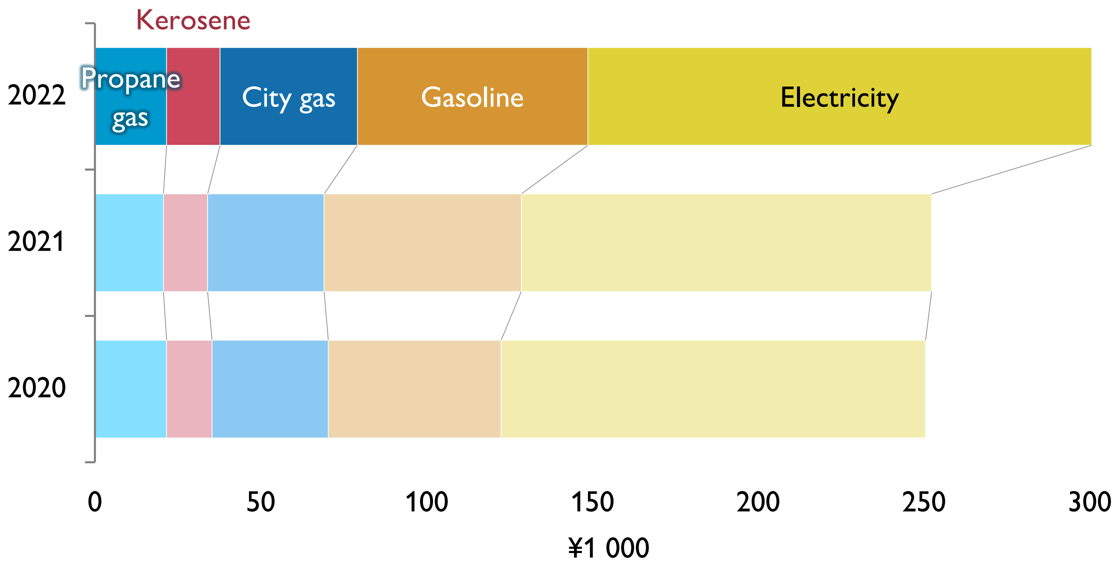
Keywords: households, energy costs, oil prices, LNG prices, yen depreciation

Liquefied natural gas (LNG) import prices remain higher than before. Not only has its price risen, but it is now well above the theoretical value based on oil prices. This suggests that even if the price of crude oil, which is the key energy price, falls to its original level, the high electricity and city gas prices that are pushing up energy bills for households will not return to their previous levels.

Household energy costs reach 300 000 yen due to price increases

Household[1] energy (electricity, city gas, propane gas, kerosene and gasoline) costs are ballooning (Figure 2), and are expected to reach 300 000 yen a year in 2022[2], a level that would match or exceed the highest ever recorded[3]. Electricity will reach a record high, gasoline will be at its highest in eight years and city gas in seven years.

Figure 2 | Household energy costs

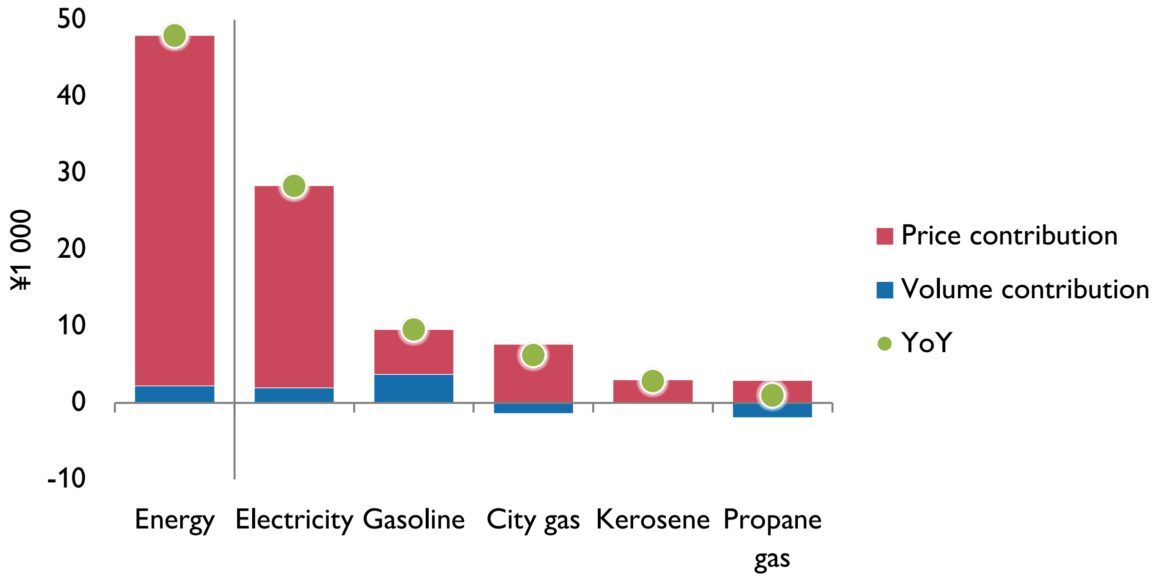


Notes: Households of two persons or more. The figures for 2022 are estimates based on actual results through October.
Source: Ministry of Internal Affairs and Communications "Family Income and Expenditure Survey"

The size of the increase over the previous year was also extremely large at ¥48 000, or 20%, in 2022. When this record increase in energy costs is decomposed into (1) the impact of an increase or decrease in energy consumption (volume contribution)[4] and (2) the impact of energy price fluctuations (price contribution), most of the increase is attributed to higher energy prices. In particular, the increase in the price of electricity, which is used by almost all households, alone pushed up energy costs by ¥26 000, equivalent to more than half of the increase (Figure 3). Electricity surpassed 50% of energy costs for the first time in 2020, then dropped to 49.1% in 2021 due to falling prices and reduced consumption. However, the substantial increase this time will cause it to exceed 50% of energy costs again in 2022.

[1] Households of two persons or more
[2] It was announced that the actual results in 2022 was ¥300 107 on 7th February 2023.
[3] The highest to date was ¥299 362 in 2014.
[4] The "Family Income and Expenditure Survey" does not cover the quantity of city gas purchased. In this paper, the amount obtained by deflating city gas bills by the consumer price index for city gas was treated as the quantity of city gas.

Figure 3 | Decomposition of energy cost changes [2022, YoY]



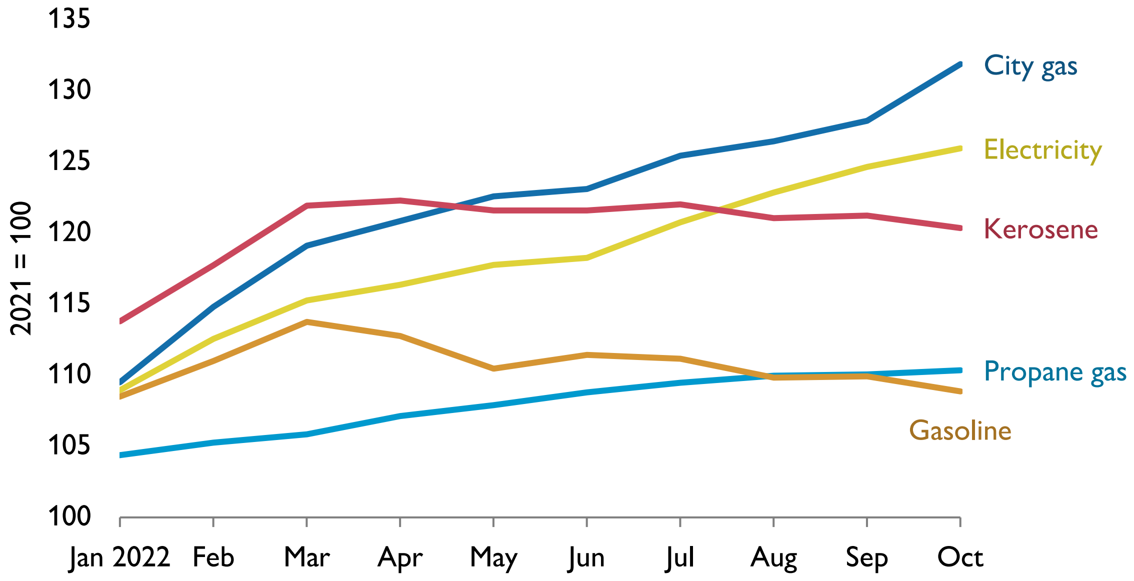
Notes: Households of two persons or more. Estimates are based on actual results through October 2022.
Source: Estimated based on Ministry of Internal Affairs and Communications "Family Income and Expenditure Survey" and Ministry of Internal Affairs and Communications "Consumer Price Index"

Gasoline was the first fuel to rise in price, but its contribution by higher prices was relatively small because the retail price increases have been eased by the subsidy program to curb extreme increases in fuel oil prices launched in January 2022. Gasoline consumption, on the other hand, increased for the first time since the start of the pandemic mainly due to a rebound effect following the slump in travel through the previous summer, pushing up energy costs. Its contribution is the largest among the volume contributions of various energies.

The price of city gas has increased faster than that of electricity since 2021 (Figure 4). However, unlike electricity, city gas is not used by households that use propane gas and all-electric houses, and households that do use city gas do not use it for power, lighting or cooling, so its average consumption[5] is usually less than that of electricity. Its price per calorific value is also lower than that of electricity, so a typical city gas bill is only about a quarter of the electricity bill. As such, the increase in city gas price will push up energy costs by just under ¥8 000. Still, this contribution accounts for about one-sixth of the total, the second largest after electricity price increases.

[5] Calorific value

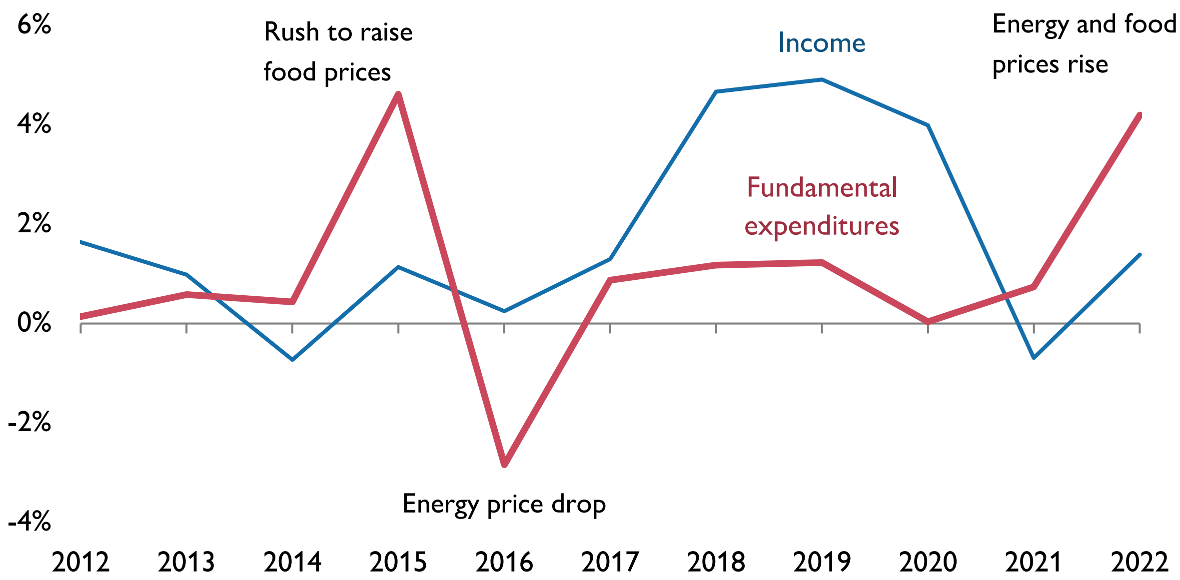
Figure 4 | Consumer price index



Source: Calculated from the Ministry of Internal Affairs and Communications "Consumer Price Index"

In 2022, income and total consumption expenditures are also expected to exceed those of the previous year. However, about half of the increase in total consumption expenditures will come from increased spending on energy and food, which are generally regarded as daily necessities. Even if income declines, energy and food must still be bought for daily life. On the other hand, even when income increases, few people are driven to spend more on these necessities than the increase in their income. In other words, a large increase in fundamental expenditures, mainly on necessities, that exceeds income growth is not the result of discretionary spending by households but reflects the rising prices of necessities. This phenomenon just symbolises the year 2022 (Figure 5).

Figure 5 | Changes in fundamental expenditures and income



Notes: Households with two workers or more. January through October for 2022
Source: Ministry of Internal Affairs and Communications "Family Income and Expenditure Survey"

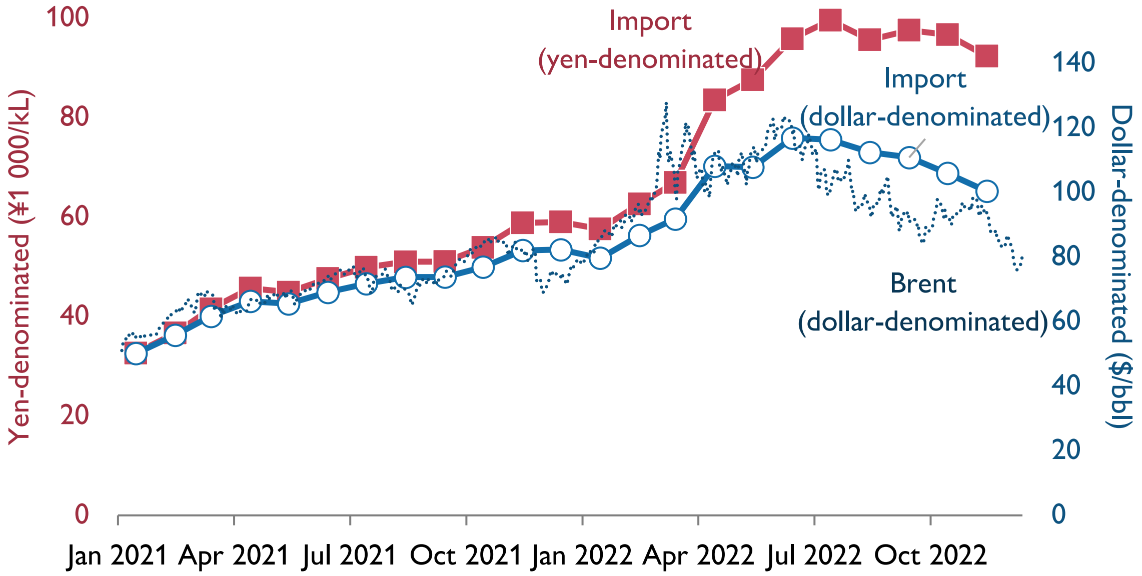
Companies that were struggling during the pandemic are experiencing some signs of recovery. Individuals are also enjoying the benefit of the easing of restrictions on travel: spending on culture and entertainment has recovered about 40% of the decline that occurred in 2020 and 2021. Nevertheless, there is little sense of improvement in living conditions, which may be partly due to the higher prices of necessities.

Changes in factors behind energy price increases and concerns

Foreign exchange rates

Domestic crude oil prices remain high, although they have softened somewhat from their all-time highs (Figure 6). Meanwhile, the price of Brent crude oil, one of the international marker oils, has been declining sharply since June 2022. In mid-December 2022, it was temporarily in the mid-$70/bbl range, down by a third from its recent peak. The main cause of high oil prices in Japan has shifted from international market conditions to the weak yen.

Figure 6 | Crude oil prices

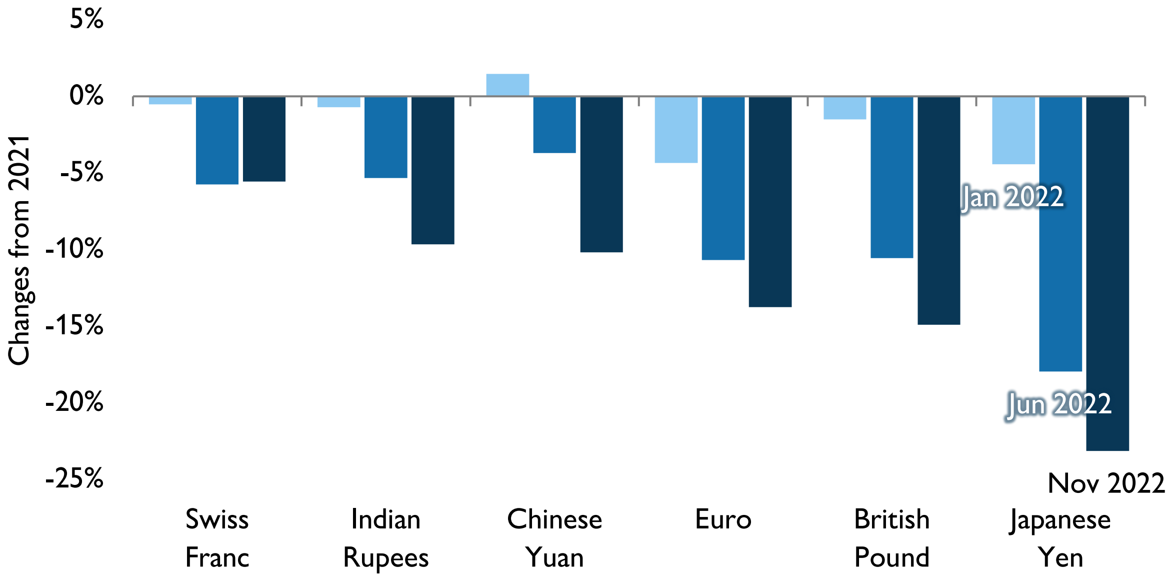


Note: November 2022 import prices are preliminary figures for crude oil and raw oil.
Sources: The Institute of Energy Economics, Japan "EDMC Energy Trend", Intercontinental Exchange

The dollar appreciated significantly and rapidly as the United States took bold monetary tightening measures to counter inflation. However, the pressure of the strong dollar eased as expectations of a slowdown in the pace of U.S. interest rate hikes spread, and the dollar weakened after October 2022. For many oil-importing countries that have been hit by the high international oil prices as well as their weaker currency, this reversal in trend has brought welcome relief.

Japan is no exception, but it cannot celebrate freely because the yen has rebounded by less compared to other major currencies. Currently, the yen has appreciated by about ¥15/$ from its recent bottom, but it is still considerably weaker than in 2021. Moreover, it remains far less valuable than other major currencies (Figure 7).

Figure 7 | Value of selected currencies against the dollar



Source: Calculated based on International Monetary Fund "International Financial Statistics"

Based on the concept of relative purchasing power parity, Japan's relatively small increase in prices is expected to lead to a stronger yen in the medium term. However, the depreciation of the yen has been slower to correct than other currencies. This is attributed to the interest rate differential between Japan, which has low interest rates despite a de facto partial revision of its massive monetary easing program in December 2022, and the United States, which is tackling inflation, as well as Japan's trade deficit, which is expected to reach a record high due to the surge in energy import payments and the J-curve effect[6]. This means that Japan may continue to pay more than other countries when importing energy, which is generally traded internationally in dollars.

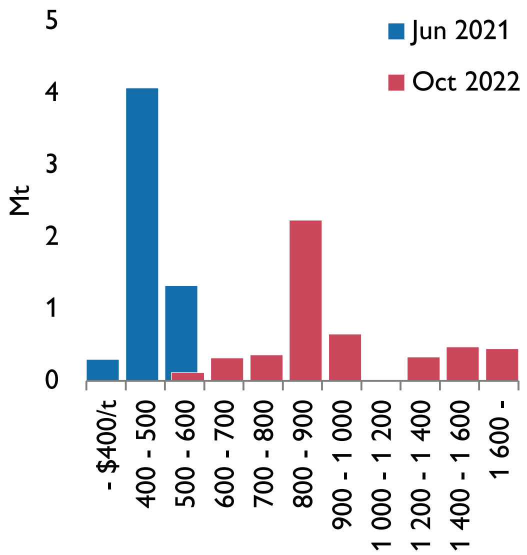
LNG import price

Natural gas prices in Europe rose in 2021, mainly due to increased demand caused by a shortage of wind power generation, and then skyrocketed with Russia's invasion of Ukraine. On the other hand, Japan's dollar-denominated import prices for liquefied natural gas (LNG) have not been as abnormally high as European natural gas prices. One reason is that most of Japan's LNG imports are based on long-term contract prices which are linked to Japan's crude oil import prices. Under the oil price-indexed system, LNG prices do not fluctuate as radically as crude oil prices. Therefore, even if oil prices rise above a certain price range, LNG prices will rise by less in comparison. As a result, this leads to a tendency for Japanese LNG prices to be relatively low during periods of high oil prices or tight natural gas supply and demand.

However, Japanese LNG prices have begun to rise by more since the fall of 2021 than they used to. This is presumably due mainly to the effect of spot transactions, whose prices soared reflecting the tight supply and demand (Figure 8). As a result, the price has not only gone up but is now well above the theoretical value based on the oil price, and is becoming visibly overpriced relative to oil prices (Figure 9).

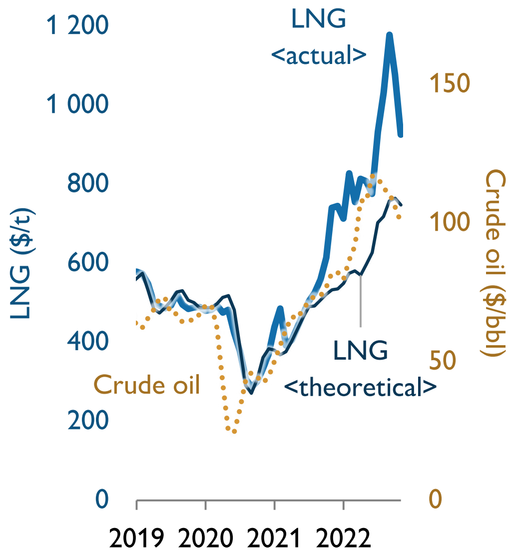
[6] Depreciation of the home currency usually improves the trade balance through an increase in exports and decrease in imports. However, trade and production structures take time to adjust. Therefore, in the short term, the ballooning effect of import value through the rise in import prices in the local currency will outweigh the increase in exports, and the trade balance may in fact worsen.

Figure 8 | Distribution of LNG imports by import price



Note: Calculated from data by import partner country and by customs
Source: Ministry of Finance "Trade Statistics"

Figure 9 | Actual LNG import prices and theoretical values based on crude oil import prices



Note: Theoretical values are estimated based on the relationship between LNG import prices and crude oil import prices in 2018-2020.

In Japan, LNG is the main fuel for power generation and accounts for 95% of city gas feedstock. If the high price of LNG is not resolved, even if the crude oil price, which is the key energy price, subsides to its original level, the high electricity and city gas prices, which are pushing up energy costs for households, will not return to their previous levels.

The Russian Risk in the Supply of Enriched Uranium

Emiri Yokota*

What is uranium enrichment?

Natural uranium that exists in the natural world contains uranium-235, which undergoes nuclear fission to release an immense amount of heat energy, and uranium-238, which is non-fissile. Uranium-235 can be used as fuel at existing nuclear power plants, but natural uranium contains only about 0.7% of it. For this reason, it is necessary to carry out work to increase the concentration of uranium-235 to about 3 - 5% to make it suitable for use in nuclear power plants. This work is known as "uranium enrichment." The uranium enrichment methods that are currently carried out commercially are gaseous diffusion and centrifuge separation. Although the gaseous diffusion method used to be the mainstream method, the pivot has now shifted to centrifuge separation.

Trends in enriched uranium production capacity worldwide

Looking at the trends in enriched uranium production capacity worldwide in recent years, we can see that Russia accounts more than 40%. Furthermore, this exceeds 60% when combined with China, which has shown a remarkable increase in its production capacity for enriched uranium. This shows clearly how great our reliance is on specific countries in the field of uranium enrichment, and how this reliance is continuing to grow.

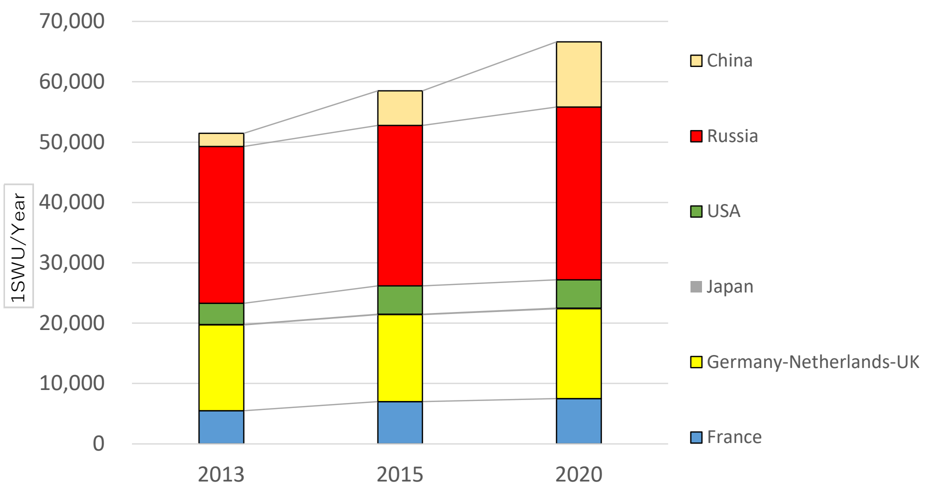


Fig. 1 Trends in enriched uranium production capacity worldwide

Source: Prepared based on "Uranium Enrichment," WNA (September 2022)

Next, looking at the future demand-supply balance for enriched uranium (Fig. 2), we can see that it is currently possible to meet global demand as long as demand does not increase rapidly. However, if we were to consider the fact that the world relies on Russia for more than 40% of its enriched uranium supply, as explained above, it may not be possible to meet demand if its supply volume were to fall significantly in situations where the United States or other countries prohibit the import of Russia-produced uranium, or where Russia prohibits the export of uranium.

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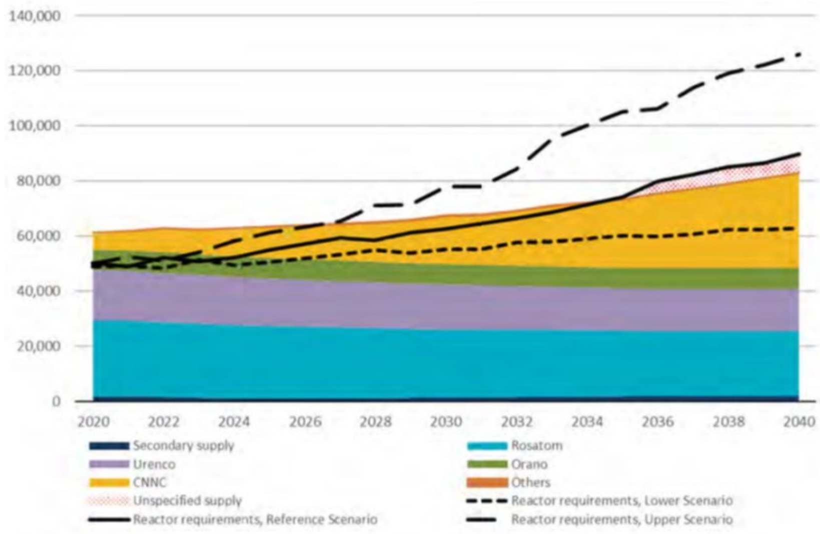

Fig. 2 Forecast of global enriched uranium demand and supply

Source: "The Nuclear Fuel Report: Expanded Summary Global Scenarios for Demand and Supply Availability 2021-2040," World Nuclear Association (April 2022)

This problem is especially prominent in the United States. Russia accounted for 14% of all uranium products imported by the country in 2021, but if we were to look only at enriched uranium, its reliance on Russia exceeds 30% (Fig. 3, approximately 4,000tSWU).

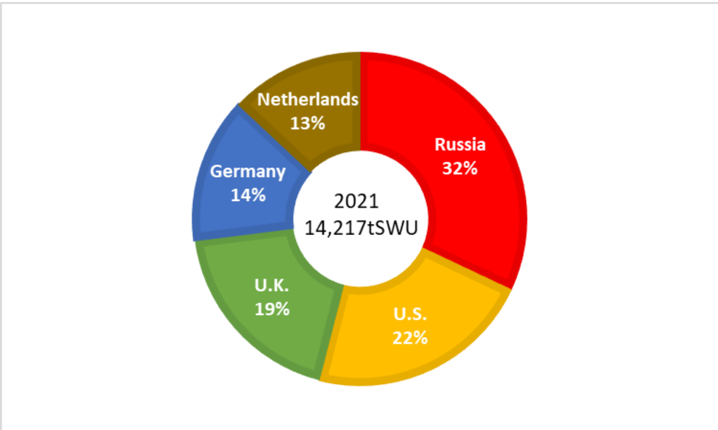

Fig. 3 Structure of enriched uranium supply in the United States

Source: Prepared based on the 2021 Uranium Marketing Annual Report (May 2022)

Currently, there is only one enriched uranium production plant (production capacity of 4,700tSWU) operating within the United States, which belongs to Louisiana Energy Services (LES), a subsidiary of the British-German-Dutch multinational, the Urenco Group[1]. Although USEC Inc. (now Centrus Energy Corp.) under the U.S. Department of Energy (DOE) is developing a centrifuge separation plant (American Centrifuge Plant or ACP), the start of its operation has been postponed time and time again, and it is unclear when it will commence full-scale operation.

It is likely that the export agreement for highly enriched uranium (HEU) from dismantled nuclear weapons, concluded between the United States and Russian governments in 1993[2], is the reason behind the fact that only one enriched uranium production plant is operating in the United States today.

[1] https://www.urenco.com/global-operations/uusa

[2] https://fissilematerials.org/library/heu93.pdf

Lingering impact of the Russia-U.S. highly enriched uranium (HEU) export agreement on the United States

After the collapse of the former Soviet Union, the international community was faced with the pressing issue of safely managing or disposing of Russia's nuclear weapons that were out of use due to nuclear disarmament. To address this problem, the United States and Russia concluded an agreement concerning the disposition of highly enriched uranium extracted from nuclear weapons (Russia-U.S. HEU Agreement dated February 17, 1993)[3]. Under this agreement, the "Megatons to Megawatts" Program was established to divert the uranium used in nuclear weapons to peaceful uses[4]. Over 20 years from 1993 to 2013, this program diluted 500 tons of highly enriched uranium (HEU) recovered from dismantled Russian nuclear weapons, and exported it to the United States as low enriched uranium (LEU) for use in its commercial nuclear reactors. The former Soviet Union had possessed more than 40,000 nuclear warheads at its peak in 1986, but it is said that approximately 20,000 of these have been disposed of through this program. Hence, this program has contributed to the peaceful use of nuclear energy by diluting about half of the nuclear warheads held by the former Soviet Union.

Looking now at the background to the establishment of this program from the viewpoint of the enriched uranium market, the United States had dominated this market until the mid-1970s. However, coupled with the promotion of nuclear power development triggered by the first oil crisis that hit in 1973, enrichment plants alone were unable to keep up with supply to meet the ever-growing demand through the use of the gaseous diffusion method, which was the mainstream method used in the enriched uranium market at the time. In view of this, countries such as the former West Germany, the Netherlands, and the United Kingdom developed uranium enrichment technology that uses the centrifuge separation method, which consumes less electricity than the gaseous diffusion method, and entered the market. These European countries contracted a part of the uranium enrichment business to the former Soviet Union even though the Cold War was still ongoing.

The United States had been importing very small amounts of enriched uranium from the former Soviet Union at the time. On the other hand, the inflow of cheap enriched uranium from the former Soviet Union led to the fall of enriched uranium prices in Europe, so electric power companies in the United States also began to purchase enriched uranium from Russia via Europe. As a result, the spot price for natural uranium which had been US$40/lbU3O8 in the latter half of the 1970s, began to drop at the start of the 1980s and plunged to around US$10/lbU3O8 by 1990.

To address this situation, in November 1991, an interim committee of domestic uranium producers in the United States petitioned the DOE and others on the former Soviet Union's dumping practices through the exporting of enriched uranium. Subsequently, an anti-dumping agreement was concluded in 1992. As a result, a tariff of 115% was imposed on the import of all uranium produced by the former Soviet Union into the United States.

At the time, there was growing risk in the former Soviet Union of nuclear substances being taken out of the country illegally amidst the social turmoil after the collapse of the Soviet regime. However, there were insufficient funds for managing nuclear substances safely. Hence, for the former Soviet Union, which had been effectively squeezed out of the U.S. market by the anti-dumping tariff, it was crucial to obtain cash by selling HEU.

In the United States as well, the DOE expected that the use of cheap Russian HEU would help to reduce the cost of enriching uranium domestically and secure supply commitments to electric power companies in the United States.

Against this backdrop, the U.S. Department of Commerce (DOC) decided to impose restrictions on the amount of uranium exported from the former Soviet Union to the United States in exchange for suspending further anti-dumping tariff investigations. A new agreement was ultimately concluded between the United States and Russia in 2008, making it possible for Russia to export up to 20% of the LEU needed for commercial reactors in the United States every year since 2014. In 2020, before Russia launched its military operation in Ukraine, it was decided that this agreement would be extended till 2040[5].

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3 https://fissilematerials.org/library/heu93.pdf
4 https://americancenterjapan.com/aboutusa/translations/2734/
5 https://www.jaif.or.jp/journal/oversea/4888.html

On the other hand, the strong reliance on Russia-produced enriched Uranium has long been perceived as a problem within the United States. As a countermeasure, the United States decided that it would gradually reduce this dependency over the next 20 years, bringing it to below 15% from 2028 onwards.

Hence, although dependence on Russian uranium has been an issue in the United States since before Russia's military operation in Ukraine and measures to reduce this dependence had been reviewed, no concrete solutions have been presented.

In March 2022 after Russia launched its military operation in Ukraine, a number of Congress members submitted a bill to the U.S. Congress to prohibit the importation of uranium from the Russian Federation, but no conclusion has been reached even now. This suggests the difficulty of securing a substitute source for Russian enriched uranium, which accounts for more than 30% (approximately 4,000tSWU) of the annual demand volume in the United States.

Future issues for the United States and other countries

After the bill to prohibit Russian uranium imports was submitted to the U.S. Congress, it was reported in June 2022 that a US$4.3-billion plan on directly purchasing uranium from uranium enrichment plants within the United States, had been formulated and submitted to the Congress[6]. As there was only one enriched uranium production plant in operation within the United States, it was presumed that this plan was targeted at the LES enrichment plant. In response, Urenco, the parent company of LES, stated in an address delivered at the Bank of America in October 2022, that it was prepared to consider expanding production capacity at all four plants owned by the Urenco Group worldwide if there were prospects of securing long-term customers[7]. However, in view that a certain amount of lead time is needed to expand production capacity in reality, there remains the issue of how to secure supply to meet current demand levels if the United States were to decide to ban Russian uranium imports.

Another issue is the supply of HALEU fuel (low enriched uranium with a maximum concentration of 20%) for next-generation nuclear reactors known as small modular reactors (SMR), for which research and development is currently being conducted by various countries.

For major countries, SMR is anticipated to fulfill an important role in their goal toward decarbonization. Among the advanced nuclear reactor designs selected by the DOE for support under its Advanced Reactor Demonstration Program (ARDP), many include plans to use HALEU fuel. This underscores the need to secure HALEU fuel for the introduction of next-generation reactors.

In the United States, the U.S. Nuclear Regulatory Commission (NRC) approved the production of HALEU fuel by ACP under Centrus Energy Corp in 2021[8]. Furthermore, in November 2022, DOE and Centrus Energy Corp. announced that they have concluded an agreement to commence production of HALEU fuel[9].

However, as explained previously, the start date of ACP's operation has been postponed time and again, and many uncertainties remain with regard to whether or not production will proceed as planned.

Currently, Russian company TENEX is the only one engaged in the production and sale of HALEU fuel to commercial nuclear reactors. Given the confrontational structure between Russia and Japan, the United States, and Europe, how the latter three can build a future supply chain for enriched uranium, including HALEU fuel supply for next-generation nuclear reactors, as well as for existing nuclear reactors, is a key question that will affect not only the stable operation of existing nuclear reactors, but also the timing for the commercialization of next-generation reactors.

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[6] https://www.bloomberg.co.jp/news/articles/2022-06-07/RD4GVQDWX2PU01
[7] https://www.urenco.com/news/global/2022/urenco-presents-to-the-bank-of-america
[8] https://www.centrusenergy.com/news/nrc-approves-centrus-energys-license-amendment-for-haleu-production/
[9] https://www.energy.gov/articles/doe-announces-cost-shared-award-first-ever-domestic-production-haleu-advanced-nuclear

Transitions under Energy Crisis: How Are Oil & Gas-Producing Countries and Energy Companies about to live through Energy Transitions? Energy Markets in Transition and CBAM◆

Miki Yanagi*

This paper outlines the current situation of Oil & Gas company's Energy Transition at first, and finally discuss challenges regarding methodologies for monitoring GHG (Green House Gases) emissions from Oil & Gas products with the viewpoint of Carbon Border Adjustment Mechanisms based on my earlier study.

1. Overview: How to strike a balance between stable energy supply and decarbonization becoming new challenges

At present, Oil & Gas operators routinely work to secure stable energy supply through value-chain. How to strike a balance between stable energy supply and decarbonization has become a new challenge after Ukraine war as a de-risked approach.

Responses to ESG investment

As response to Task Force on Climate-related Financial Disclosures (TCFD) settled by the requests of G20 and FSB (Financial Stability Board) financial institutions, energy companies introduced quantifiable indicator as Key Performance Indicators (KPIs) including its future's expansion of KPIs toward Net Zero emission. However, specific selection of KPIs such as, GHG emissions, share of upstream GHG intensity, product's carbon footprint, and renewable energy installed capacity etc., which differ widely from each other, as noted in later discussion on transitions.

Many companies also prioritized stakeholder involvement, dialogue, and it seems that transparency and prompt decision-making have become more important than ever.

Addressing Scope 3 reports

The author had some opportunities to witness a good-faith, discussion on how to invest in decarbonizing technologies and disclose information on GHG emissions, by oil-producing companies.

For instance, whether emission disclosure reports should cover Scope 3 emissions in the products use stage (end-use)[1],and whether Scope 3 should be subjected to decarbonization goals may become one of significant issues for those board members.

◆ Acknowledgement: The writing of this paper was inspired by an Oxford Energy Seminar (OES) held September 2022. I very much appreciate the opportunity to attend. However, the content of this paper is based on the author's analysis and other interviews.

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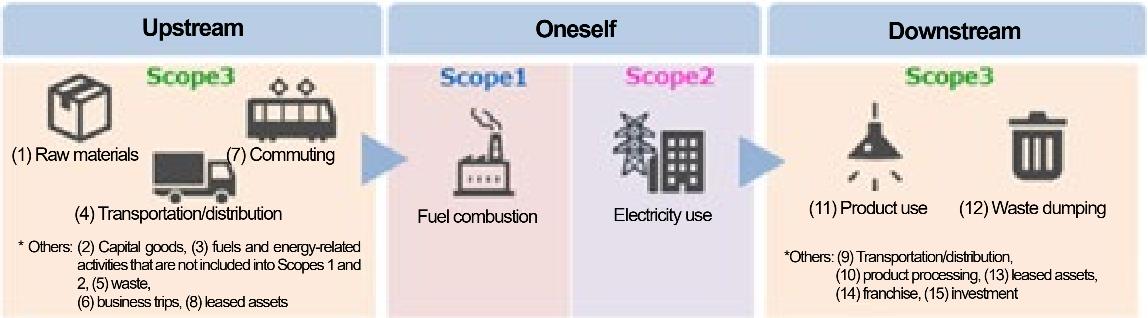
[1] Case of ExxonMobil: Seeking net-zero emissions in Scopes 1 and 2 by 2050. Scope 3 emissions estimated number are published with the specific citation.
Case of Royal Dutch Shell case: Setting target is to become a net-zero emissions energy business by 2050 covering Scope 3.
As for scope 3, GHG Protocol, for which a guideline has been given by the World Resource Institute and the World Business Council for Sustainable Development (WRI/WBCSD), classifies Scope 3 emissions into 15 categories. WRI/WBCSD, "Greenhous Gas Protocol Corporate Value Chain (Scope 3) Standard."



Scope 1: Direct GHG emissions by the reporting company itself. (fuel combustion, industrial processes)
Scope 2: Indirect emissions from use of electricity, heat, or steam supplied by others
Scope 3: Indirect emissions other than Scopes 1 and 2 (emissions by others related to the company's activities)

Fig. 1 Image of Scope 1, 2, 3 GHG emissions

Source: Ministry of the Environment, Japan

Market Dynamics in Decarbonization

There is a hypothesis that Saudi Arabia, the most cost-competitive oil producing country, could play a key role in such a situation. It seems to me that Saudi Arabia may send messages to market that it may take advantage of its affordable energy resources to launch investment in and supply of green products (hydrogen,[2] and plastics and other chemicals made from renewable energy) whenever there are market needs. Green market differentiation among resource-rich countries may start to begin. Saudi Arabia may exploit green and other decarbonized fuels for its survival. As discussed later, there were concern that the harmonized methodologies to monitor GHG emissions is failing to make progress for oil and gas producers.

Transitions rather than a single transition pathway:
Even EU energy companies' decarbonization pathways are diverse

Energy transition pathways differ by companies and its assets. Particularly, EU energy companies set forth various decarbonization approaches. EU companies were slightly divided over their attitude of whether priority should be put on hydrogen. Some companies placed hopes on CCS while others brushed off CCS. In an extreme case, one company offered to minimize CCS and offsetting credit use. Perhaps this is a result of existing assets and value chains.

Positiveness to offset credit uses: EU companies' attitudes are divided

Regarding offset credit uses, some companies pointed out reputation risks. In contrast, some others mentioned REDD credit (Reducing Emissions from Deforestation and forest Degradation), as well as the role of conservation, sustainable management of forests and enhancement of forest carbon stocks in developing countries (REDD+), indicating their environmental integrity to tackle these initiatives. Some companies are also promoting the transparency and disclosure, and the cautious selection and verification of REDD projects.

With regard to "carbon-neutral LNG", Stern (2022)[3] pointed out that "Owners and operators of assets in the different segments of the supply chain should take responsibility for MRV[4] of emissions from those assets. For sellers this would include emissions from the wellhead to the loading arm of the LNG ship (i.e. all upstream segments plus liquefaction)" and "the LNG community must be able to credibly document its emissions which will become an increasingly critical part of

[2] Some companies cited transition toward hydrogen, without discussing development of value chains including the consumption stage and of hydrogen infrastructure.
[3] Stern, J. (2022), "Greenhouse Gas Emissions from LNG Trade: from carbon neutral to GHG-verified". The Oxford Energy Institute for energy study, September 2022.
[4] Measurement, Reporting, and Verification

its social license to operate."

De-risking for decarbonization and economic security: Responses to critical minerals

The world may plunge into "stagflation," or a recession accompanied by energy and other price hikes, and see "progress in de-globalization" with nationalism gaining momentum. Given that renewable energy indispensable for decarbonization have been supported by solar panels, heat pumps, and other products, economic security challenges related to decarbonization were pointed out.

U.S. Inflation Reduction Act of 2022 (IRA)[5]

The IRA passed by the U.S. Senate on August 7, 2022, has been called the largest climate bill in U.S. history. While the U.S. Nationally Determined Contributions (NDCs) under the Paris Agreement seeks to cut GHG emissions by 50-52% from 2005, the IRA is expected to cut emissions by up to 40%. Much of financial support is through tax credits. One of supports for hydrogen production amounts to up to \$3/kg-H_2 as long as CO_2 emissions are limited to 0.45 kgCO_2/kg-H_2. For Carbon dioxide Capture and Storage (CCS), the Section 45Q tax credit expands from \$50/ton-CO_2 under the Trump administration to \$85/ton-CO_2. For Direct Air Capture (DAC), the tax credit increases from \$50/ton-CO_2 to \$180/ton-CO_2. Other support includes \$3.5 billion in additional funding for DAC hubs.

Challenges towards COP27/28 hosted by oil-producing countries

Egypt hosted the 27th Conference of Parties to the United Nations Framework Convention on Climate Change (UNFCCC COP27) in 2022 before the United Arab Emirates hosts the UNFCCC COP28 in 2023. Usually, host countries have launched their respective initiatives.[6]

Given that an oil-producing country successively hosts a UNFCCC COP meeting, decarbonization initiatives for promoting gas and oil companies' investment in decarbonization may be proposed.

Ahead of the COP27, in fact, Saudi Arabia created a \$1.5 billion technology investment fund for promoting investment in "inclusive energy transition" and announced its participation in the first voluntary carbon credit auction sponsored by the Public Investment Fund (PIF).

2. Issues regarding the EU Carbon Border Adjustment Mechanism: May become de facto standards for monitoring GHG emissions from oil and gas

I have conducted earlier studies[7] on the EU Carbon Border Adjustment Mechanism (CBAM). Building on my earlier studies and the above discussion, I derive the following implications.

Background

The EU's CBAM is designed to impose carbon tariffs on imports into the EU region. This means that the EU would require importers to report GHG emissions from imported goods and pay CBAM certificates which reflect auction prices under the EU Emissions Trading System according to explicit carbon price payments (carbon tax or emission trading systems) in exported countries. EU decided imposing a tax on chemicals, fertilizer including ammonia, steel and other hard

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[5] For details, see Ueno,T (2022), "Climate Change Investment under the U.S. Inflation Reduction Act" in Japanese .https://criepi.denken.or.jp/jp/serc/discussion/22007.html
The Whitehouse (2022) "Inflation Reduction Act Guidebook" https://www.whitehouse.gov/cleanenergy/inflation-reduction-act-guidebook/

[6] For instance, the United Kingdom put forward the following initiatives in 2021. The British initiative of "Glasgow Breakthrough" for international cooperation in the acceleration of clean technology development and diffusion over the next decade was joined by all Group of Seven countries including Japan. Among other initiatives was the Glasgow Financial Alliance for Net Zero (GFANZ) launched by Mark Carney and others.

[7] Yanagi, M. *et al.* (2021), "The Carbon Border Adjustment Mechanism: Collaboration or Confrontation? https://eneken.ieej.or.jp/en/report_detail.php?article_info__id=9943
Yanagi, M and Morimoto, S (2023) "EU Agreed on World's First CBAM – Summary Bulletin
Phasing out free allowance to steel and other sectors by 2034 in transition to the Carbon Border Adjustment Mechanism (CBAM) Tensions of potential Green Trade War" https://eneken.ieej.or.jp/data/11118.pdf

to abate sector imported goods[8] in proportion to emissions accompanying their production.

GHG emissions monitoring and enhancing transparency – The key is third-party certification.

In the current situation, oil and gas companies individually acquire third-party certification in response to requirements of the U.S. Sustainability Accounting Standards Board (SASB), etc.[9] Many businesspersons and researchers thought that, in addition to a lack of international common rules for monitoring GHG emissions. According to them, it may be hard to find appropriate an international forum for building consensus to integrate such rules. At present, GHG emissions may be monitored on a project-by-project basis. There were some concerns about the development of common methodologies for monitoring emissions that do not take its spectrum by region or well into account. Supply-side players may have challenges regarding monitoring methodology on green products (which uses renewables) and/or blue products (which uses CCS).

Attracting attention recently are methane emissions MRV methods of the Oil & Gas Methane Partnership (OGMP) 2.0[10] of oil and gas companies, in partnership with the European Commission, the United Nations Environment Program (UNEP), the Environmental Defense Fund (EDF), Climate and Clean Air Coalition and Clean Air Task Force.[11]

According to the CBAM regulation[12], the EU CBAM stipulates reporting duties to importers on Scope 1 GHG emissions (steel, aluminum, hydrogen) and Scope 1&2 (cement, fertilizer, electricity) from October 2023. Scope 1 covers emissions from oil and gas combustion. Therefore, oil and gas companies have to support customers on their carbon footprint.

In this sense, the absence of global common rules to monitor GHG emissions may be a matter of concern. As for Scope 2, the European Commission shall present a report on calculation methodology and possibility of expanding to indirect emissions (Scope 2) of the goods for industries covered only by Scope 1 by the end of 2025. Also, the possibility of expansion for transport services of goods (a part of Scope 3) will also be considered by European Commission at the same time. It would be remaining issues for oil & gas sectors, especially for utilization of blue or green hydrogen products.

While EU's CBAM regulation may be inconsistent with fundamental WTO (World Trade Organization) rules (Yanagi 2022)[13], the CBAM regulation officially entered into force the day following its publication in the Official Journal of the EU on 16 May 2023. The detailed rules for reporting methodology for GHG emissions from oil and gas which will be stipulated by Implementing Act, and Delegated Act may serve as the framework for future emissions accounting including hydrogen.

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[8] CBAM regulation defines goods and products differently.

[9] The Value Reporting Foundation (VRF), into which the International Integrated Reporting Council (IIRC) and the SASB merged in June 2021, was integrated into the IFRS (International Financial Reporting Standards) Foundation, which develops international disclosure standards for ESG information on August 1, 2022 (source: Japan Exchange Group "Introduction to ESG information disclosure frameworks").

[10] The OGMP was established through a climate summit in 2014. At present, the 2006 IPCC (Intergovernmental Panel on Climate Change) Guidelines for National Greenhouse Gas Inventory stipulates approaches and methodologies for GHG emissions monitoring inventory by country. The OGMP 2.0 addresses the improvement of data use, compatibility with such guidance and the improvement of accuracy. The OGMP says, "The guidelines of IPCC (Rewritten by the author to abbreviation) and the OGMP 2.0 reporting framework are congruent, but the OGMP 2.0 adds a higher level of granularity to the IPCC's Tier 3 reporting by requiring the reconciliation of the source-level and site-level reporting." https://ogmpartnership.com/faq/

[11] Also, the pressure from finance sector for disclosure should not be overlooked. In addition to the TCFD, there is also an attempt toward Net Zero. The Glasgow Financial Alliance for Net Zero (GFANZ) comprising financial institutions requires its members to make commitments to seek Net Zero emissions in all scopes including Scope 3 in 2050, set out intermediate goals for 2030 and realize transparent reporting, information disclosure.

[12] Regulation (EU) 2023/956 of the European Parliament and of the Council of 10 May 2023 establishing a carbon border adjustment mechanism, Official Journal of the European Union, Volume 66 Legislation 16 May 2023

[13] Yanagi summarized previous studies written by international trade lawyers.
Yanagi, M. (2022), "Chapter 9 Carbon Neutrality and Trade Challenges – Focusing on Carbon Border Adjustment Mechanism," in "Recommendations for the Development a Rules-Based International Economic System – International Economy Series 1," edited by Japan Economic Foundation, pp.138-150, December,2022. https://eneken.ieej.or.jp/data/11117.pdf

LNG Marine Transportation Market Trends
- FSRU as Europe's Way Out of Russia -

Seiya Matsukura*

1. Introduction

The world handled 372.3 Mt (Million tonnes) of LNG in 2021, up 16.2 Mt from the previous year, with 19 LNG exporting countries and 44 LNG importing countries, including the newly added Croatia. The importance of LNG marine transportation will continue to grow. In Europe, a major consumer of natural gas, LNG imports accounted for 114.8 Bcm (Billion cubic metres) (about 80 Mt) of the 561.9 Bcm (about 410 Mt) of natural gas imports in 2020, and pipeline (PL) imports accounted for 447.1 Bcm (about 330 Mt). Of the PL imports, Russian gas accounted for 167.7 Bcm (120 Mt), or 38%, but the invasion of Ukraine in February 2022 prompted Europe to make a sharp policy shift away from dependence on Russian gas. Currently, there are 33 land-based LNG import terminals and 6 floating LNG terminals in operation in Europe, and the introduction of FSRUs (Floating Storage and Regasification Units), which have short lead times, is particularly urgent. This paper reviews the LNG marine transportation market, summarizes the progress and challenges in the introduction of FSRUs as part of Europe's efforts to move away from Russia.

2. LNG Marine Transportation Market Trends

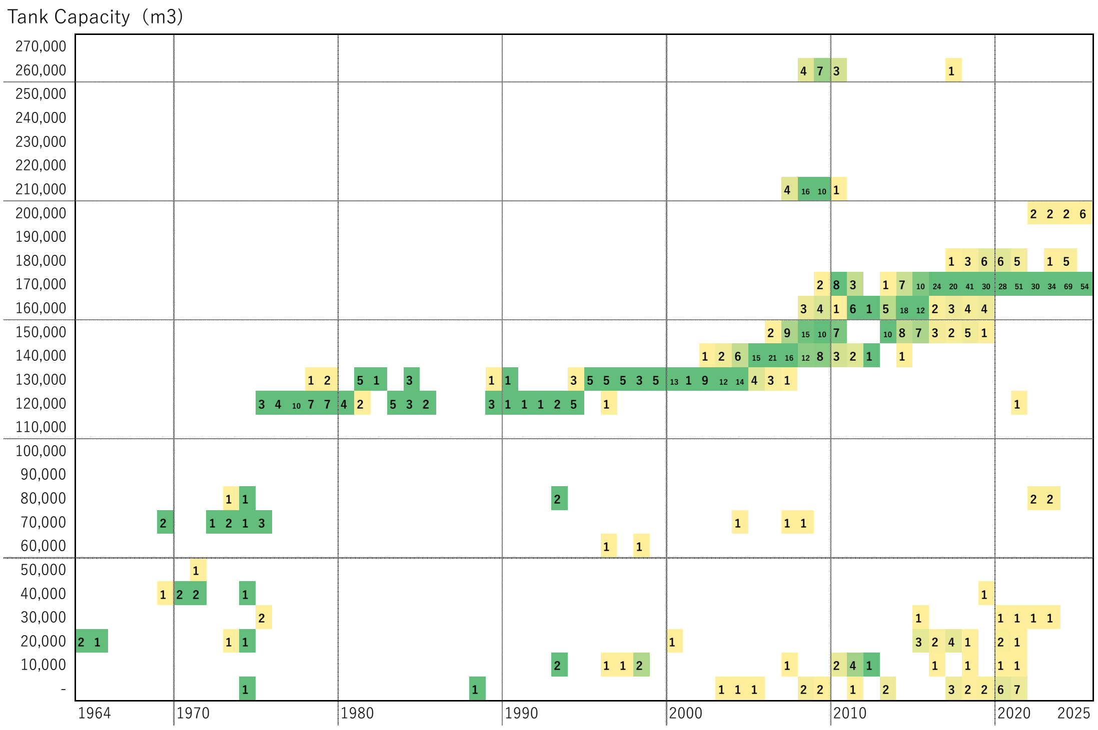

Fig. 1 LNG Carriers Delivered by Capacity (1964-2025) *Including FSRU and LNG bunker vessels

* Former Senior Researcher, Gas Group, Fossil Energies & International Cooperation Unit, IEEJ

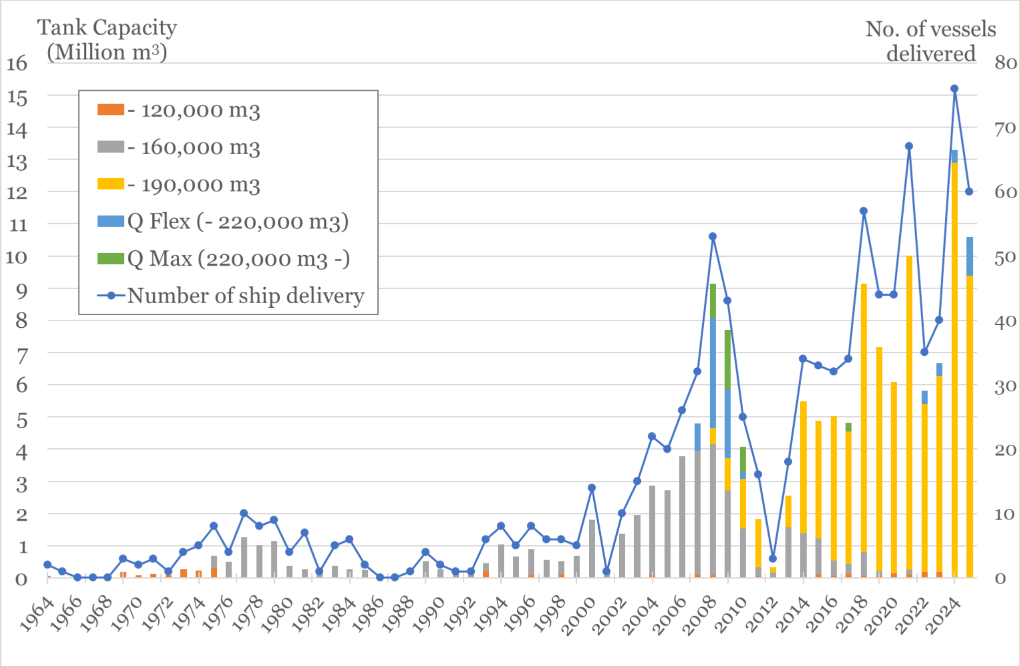

Fig. 2 LNG Carriers Delivered (1964-2025) *Including FSRU and LNGBV

Source: IEEJ from various sources

Regarding new LNG carriers, 68 were delivered in 2021 (47 in the previous year), a record high. This includes 5 FSRUs, 10 small vessels[1] (including 8 LNG bunkering vessels (BVs)), and 53 LNG carriers, bringing the total number of LNG carriers in operation to 700 (including 48 FSRUs and 31 small vessels). The average capacity of new delivered (excluding FSRUs and small vessels) was 174,897 m^3, reflecting the design of Panamax vessels[2] as standard (Fig. 1, Fig. 2).

With 111 new LNG carriers ordered in 2021 and 40 in 2020 the total number of newbuild ships on order as of the end of 2021 was 196, including 5 FSRUs and 25 small vessels (22 LNGBVs and 3 LNG carriers). The number of LNG carriers ordered is expected to remain at a high level. On the other hand, the deliveries of LNG carriers on order will be extended beyond 2026 or later, as available dock spaces at shipyards by 2025 have been booked out. One of the factors is QatarEnergy's (QE) LNG transportation arrangements for both the Qatar NFE (North Field East) LNG expansion and the Golden Pass LNG project in the United States. Specifically, in April 2020, QE signed a USD 3 billion contract with Hudong-Zhonghua Shipbuilding Corporation, a subsidiary of China State Shipbuilding Corporation (CSSC), to reserve shipbuilding capacity until 2027, and in June 2020, QE signed a contract with three major shipbuilders in Korea, Daewoo Shipbuilding & Marine Engineering (DSME), Hyundai Heavy Industries (HHI), and Samsung Heavy Industries (SHI), to reserve the majority of their shipbuilding capacity until 2027 (USD 19.2 billion). The size of these shipbuilding capacities is estimated to be equivalent to about 60% (over 100 vessels) of the world's LNG shipbuilding capacity by 2027.

3. FSRU Market Trends

3-1. FSRU (Floating Storage & Regasification Unit)

An FSRU is an LNG carrier or a floating structure equipped with LNG storage and regasification facilities and moored at a pier to perform the same function as an onshore LNG receiving terminal (Fig. 3). Other types of LNG storage vessels include LNG RVs (Regasification Vessels), which transport LNG themselves, moor offshore, and deliver the vaporized gas using subsea PLs, and FSUs (Floating Storage Units), which do not have regasification facilities. Applications include short-

[1] Ships of less than 50,000 m^3 are thereafter listed as small vessels.
[2] The largest vessel type that could pass through the old Panama Canal with a full load before the 2016 expansion.

term demand increases such as seasonal demand increases, energy security, transitional use until the completion of an onshore terminal by taking advantage of the flexibility of installation and removal, and LNG trial installations.

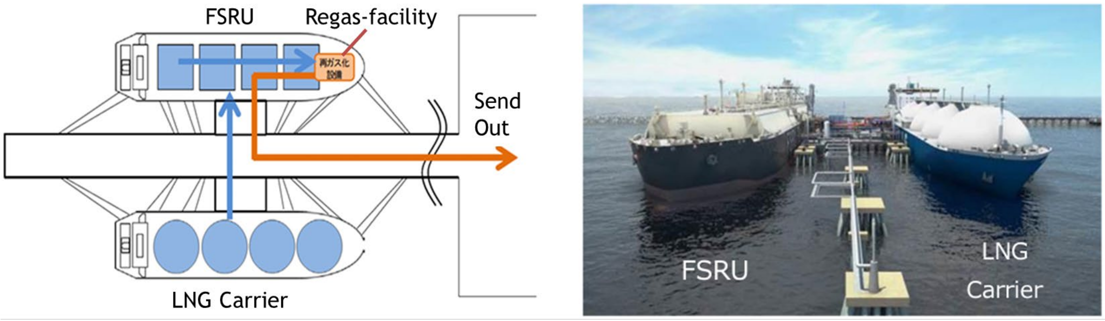

Fig. 3 Gas supply by FSRU, Ship-to-Ship (STS) system

Source: MOL, JOGMEC, Engie

3-2. Comparison with Onshore LNG receiving terminal

Table 1 Comparison of FSRUs and Onshore LNG receiving terminal

Item	FSRU	Onshore terminal
Expenses	○ Low CAPEX (New delivered: USD 300-500 million) ・Converted vessels: Less than half of new ones are expected. In addition, jetty, breakwater, etc. are required. × High OPEX (~USD 280,000/day @ 4 Mt/y)	× High CAPEX (~USD 1 billion) ○ Low OPEX (~USD 130,000/day @ 4 Mt/y)
Lead Time	○ Short (New shipping: approx. 3 years from contract) ・Renovated vessels: about 1 to 2 years. /Existing ship lease: approx. 0.5 years at the earliest. ・Relatively few permits and licenses required.	× Long (approximately 4-5 years or more) ・Complex and lengthy permitting process
Removal/ Diversion	○ Possible (conversion to other areas or LNGC). ・Reduction of stranded asset risk.	× Basically not possible
Extensibility	× Low (tank and vaporizer capacity limitations)	○ High (can be increased to meet demand)
Secure	△ Affected by ocean and weather conditions	○ Less susceptible to ocean and weather

Compared to onshore terminals, FSRUs are suitable to short-term use to meet demand surges and transitional use due to their lower CAPEX, shorter lead time from investment decision to installation, and flexibility in dismantling and conversion. On the other hand, onshore are suitable to long-term demand, due to superiority in stable supply and scalability against rough weather and sea conditions (Table 1).

3-3. FSRU Market Trends

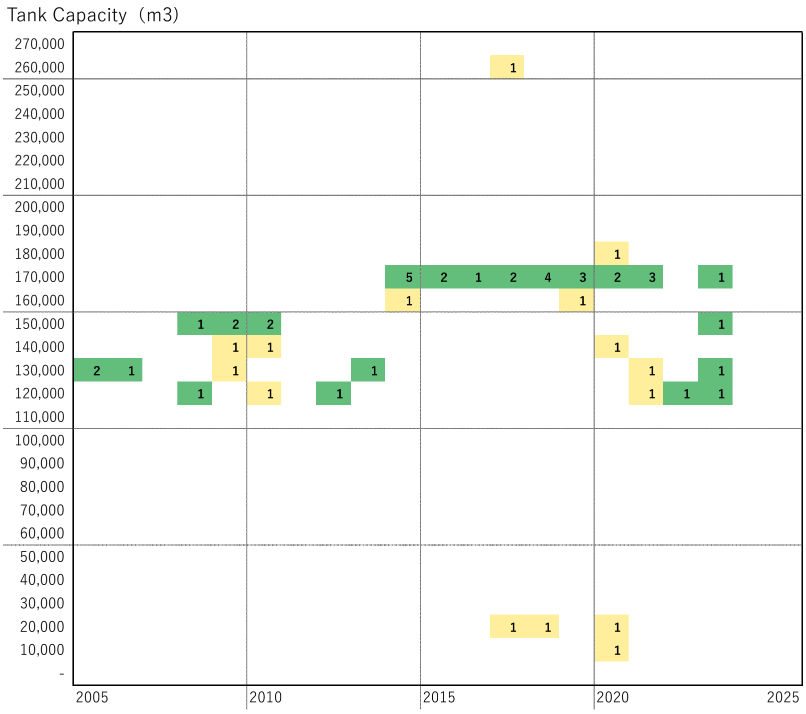

Fig. 4 FSRU Delivered by Capacity (2005-2023)

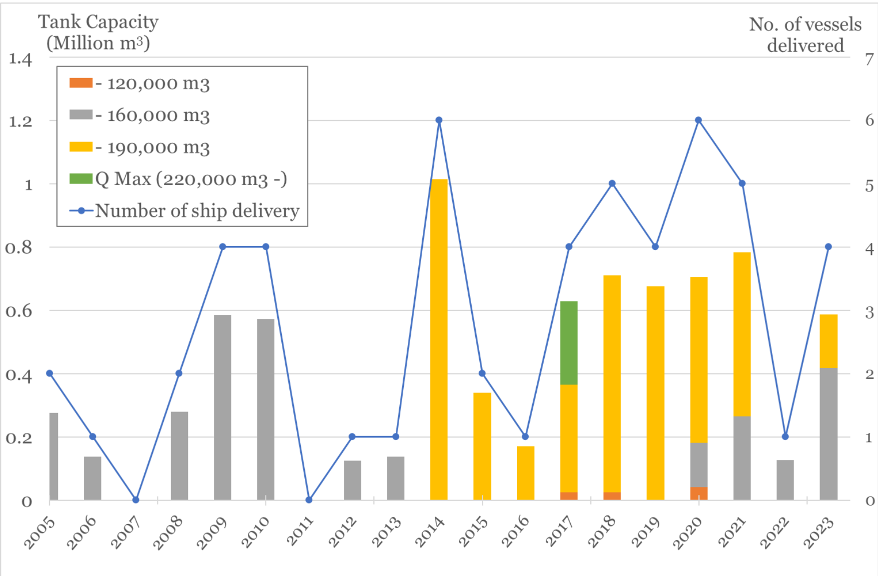

Fig. 5 FSRU Delivered (2005-2023)

As for FSRUs, 48 units were in operation at the end of 2021, including 10 FSRUs which converted from conventional LNG carriers, and 5 units under construction (including 4 converted). As for capacity, since 2014, many 170,000 m^3 class vessels have been introduced, similar to LNG carriers. The total capacity at the end of 2021 was about 7.1 Mcm (Million cubic metres), doubling in the last five years (Fig. 4, Fig. 5).

3-4. Changes in the FSRU market after the invasion of Ukraine

Table 2 List of FSRUs (as of end of 2021)

No.	Built	Vessel Name	Send out (MTPA)	Storage (m3)	Owner	Location (As of 2021)
1	1977/2010	Golar Freeze	3.6	125,000	New Fortress Energy	Old Harbour, Jamaica
2	1977/2012	Nusantara Regas Satu (ex Khannur)	3.0	125,000	New Fortress Energy	Nusantara, Indonesia
3	1981/2008	Golar Spirit	1.8	129,000	New Fortress Energy	Laid up
4	2003/2013	FSRU Toscana (ex Golar Frost)	2.8	137,500	OLT Offshore	Toscana, Italy
5	2004/2009	Golar Winter	3.8	138,000	New Fortress Energy	Pecem, Brazil
6	2005	Excellence	3.8	138,000	Excelerate Energy	Moheshkhali, Bangladesh
7	2005	Excelsior	3.5	138,000	Excelerate Energy	Hadera, Israel ⇒ Albania (2023)
8	2006	Summit LNG (ex Excelerate)	3.8	138,000	Excelerate Energy	Summit LNG, Bangladesh
9	2008	Explorer	6.0	150,900	Excelerate Energy	Jebel Ali, Dubai, UAE
10	2009	Express	3.8	151,000	Excelerate Energy	Ruwais, Abu Dhabi, UAE
11	2009	Exquisite	4.8	150,900	Nakilat-Excelerate Energy	Port Qasim Karachi, Pakistan
12	2009	Neptune (ex GDF Suez Neptune)	3.7	145,130	Höegh LNG	LNGC ⇒ German(2023)
13	2010	Cape Ann (ex GDF Suez Cape Ann)	3.7	145,130	Höegh LNG	Tianjin, China ⇒ France (2023)
14	2010	Exemplar	4.8	150,900	Excelerate Energy	Argentina ⇒ Finland (2022)
15	2010	Expedient	5.2	150,900	Excelerate Energy	GNL Escobar, Argentina
16	2014	Experience	6.0	173,400	Excelerate Energy	Guanabara Bay, Brazil
17	2014	Golar Eskimo	3.8	160,000	New Fortress Energy	Aqaba, Jordan
18	2014	Golar Igloo	5.8	170,000	New Fortress Energy	Kuwait ⇒ Netherland (2022)
19	2014	Höegh Gallant	2.8	170,000	Höegh LNG	Old Harbour, Jamaica
20	2014	Independence	4.0	170,000	Höegh LNG ⇒ Klaipėdos Nafta (KN)	Klaipeda, Lithuania
21	2014	PGN FSRU Lampung	2.9	170,000	Höegh LNG	Lampung LNG, Indonesia
22	2015	BW Singapore	5.7	170,000	BW Gas	Egypt (-2023) ⇒ Italy (2024)
23	2015	Golar Tundra	5.5	170,000	Golar LNG	LNGC ⇒ Italy (2023)
24	2016	Höegh Grace	4.0	170,000	Höegh LNG	Cartagena, Colombia
25	2017	BW Integrity	5.0	170,000	BW Gas	Port Qasim GasPort, Pakistan
26	2017	Höegh Giant	3.7	170,000	Höegh LNG	Jaigarh, India
27	2017	Bauhinia Spirit/ MOL FSRU Challenger	4.1	263,000	MOL / Vopak	(Hong Kong) ⇒ Singapore (2022)
28	2017	Exmar S188 (ex Exmar FSRU)	4.6	25,000	Exmar Offshore	Laid up ⇒ Netherland (2022)
29	2018	Golar Nanook	5.5	170,000	New Fortress Energy	Sergipe, Brazil
30	2018	Höegh Esperanza	6.0	170,000	Höegh LNG	LNGC ⇒ German (2022)
31	2018	Höegh Gannet	5.5	170,000	Höegh LNG	LNGC (Santos, Brazil)
32	2018	Karunia Dewata	0.4	26,000	JSK Group	Benoa, Indonesia
33	2018	Marshal Vasilevskiy	2.0	174,000	Gazprom	Kaliningrad, Russia
34	2009/2019	BW Batangas (ex BW Paris)	4.2	162,500	BW Gas	LNG ⇒ Philippines (2023)
35	2019	BW Magna (ex BW Courage, Açu FSRU)	5.7	173,400	BW Gas	Port Açu, Brazil
36	2019	Höegh Galleon	3.7	170,000	Höegh LNG	LNGC (Australia) ⇒ German (2022)
37	2019	Turquoise (ex Turkey FSRU)	5.7	170,000	Kolin Construction	Etki, Turkey
38	2020	Excelerate Sequoia	6.0	173,400	Maran Gas Maritime	Bahia, Brazil
39	2016/2020	FSRU Hua Xiang(ex. Hua Xiang 8)	0.1	14,000	Zhejiang Huaxiang	Amurang, Indonesia
40	2020	FSRU Jawa Satu	2.4	170,000	PT Jawa Satu Regas	Java, Indonesia
41	2005/2020	LNG Croatia (ex Golar Viking)	1.9	140,208	LNG Hrvatska	Kirk, Croatia
42	2020	Torman	2.0	28,000	Gasfin Development	Tema LNG, Ghana
43	2020	Vasant 1	5.0	180,000	Swan Energy	Jafrabad , India
44	2003/2021	BW Tatiana (ex Gallina)		137,001	BW Gas Invenergy JV	El Salvador
45	2021	Ertugrul Gazi	4.1	170,000	BOTAS	Dörtyol, Turkey
46	1994/2021	LNGT Powership Africa (ex Dwiputra)		127,386	KARMOL	Senegal
47	2021	Transgas Force		174,000	Dynagas	LNGC ⇒ German (2023)
48	2021	Transgas Power		174,000	Dynagas	LNGC ⇒ German (2023)
49	1991/2022	LNGT Powership Asia (ex NW Shearwater)		127,500	KARMOL	Brazil
50	2002/2023	ETYFA Prometheas(ex Galea)		136,967	DEFA	Cyprus
51	2010/2023	TBN (ex Gaslog Chelsea)		153,000	Gaslog	Greece
52	1994/2023	TBN (ex LNG Vesta)		127,547	KARMOL	Mozambique
53	2023	TBN		170,000	Wison Offshore	-
-	2003/2024	Golar Arctic		140,000	Golar LNG ⇒ Snam	LNGC ⇒ Italy (2024)

Source: Compiled by IEEJ from GIIGNL

While global demand for LNG carriers has been increasing, new deliveries of FSRUs have slowed since 2018. As of the end of 2021, 10 vessels, or about one-fifth of the total, had either been temporarily used as LNG carriers (LNGCs) or were effectively idle. However, after Russia's invasion of Ukraine in February 2022, the situation changed drastically, and by mid-2022, all FSRU vessels, including existing, newly built and under-conversion, had been effectively sold out. In addition, there have been a number of moves to divert to Europe from FSRU projects already in operation in other regions (Table 2).

3-5. Major FSRU operators

In the FSRU market, Golar LNG, Höegh LNG, and Excelerate Energy are three well-established companies, and the strengths of each company include standardization of specifications through multi-owned and chartered vessels, cost reduction, and operational flexibility. Other companies are also diversifying their services, with MOL (Mitsui O.S.K. Lines) and Karpowership launching the world's first LNG power generation vessel business under the KARMOL brand in 2019, and Golar LNG selling a portion of its business to NFE (New Forest Energy) in 2021. New entrants and diversification of services are underway. The characteristics of the main FSRU operators are summarized below.

(1) Golar LNG

Norwegian company started LNG transportation business in 1970, and has recently entered into FSU and LNG trading business. In April 2021, it sold Golar LNG Partners LP and Hygo Energy Transition, part of its business, to NFE in an effort to restructure its asset portfolio. The company has chartered 8 FSRUs owned by other companies.

(2) Höegh LNG

Established in 2006 as a subsidiary of Leif Höegh & Co, a Norwegian LNG shipping company, and since 2009 has been rapidly expanding its offshore vaporization business using its own FSRUs. With 10 FSRUs owned by the company, it is the world's largest FSRU supplier.

(3) Excelerate Energy

Established in the United States in 2003, The company has been engaged in LNG transportation and LNG receiving business using FSRUs. In 2005, the company started commercial operation of the world's first FSRU (LNG RV type), followed by a policy shift to the pier-fixed type that has now become the mainstream. The company will promote the introduction and operation of FSRUs in the Middle East, South America, Asia, and other regions, centering on the 8 FSRUs owned by the company.

(4) New Fortress Energy (NFE)

Established in the United States. in 2014, NFE owns and operates natural gas and LNG-related infrastructure, vessels, and logistics assets. In August 2022, the company established a JV Energos Infrastructure (80% Apollo managed fund, 20% NFE) with Apollo to operate 11 LNG The company will operate 11 LNG related vessels, including 6 FSRUs, 3 FSUs, and 2 LNG carriers.

(5) Mitsui O.S.K. Lines (MOL)

Established in 1884, MOL is the world's largest LNG carrier and the only Japanese company to own and operate an FSRU. The company delivered the world's largest vessel, the MOL FSRU Challenger (renamed Bauhinia Spirit) (263,000 m^3) in October 2017, and in August 2019 Together with Karpowership, the company launched the world's first LNG power generation vessel business under the unified KARMOL brand.

3-6. Major FSRUs introduced in each country

As of the end of 2021, 48 FSRUs are in operation, 13 in Asia, 11 in the Americas, 6 in the Middle East, 6 in Europe, 2 in Africa, and 10 are as LNGC. Below is an overview of the non-European regions.

(1) Americas

In Puerto Rico, a U.S. territory in the West Indies, the San Juan LNG receiving terminal (FSRU) went operational in 2020, and in Argentina, Excelerate Energy's FSRU Exemplar is operating at the Bahía Blanca port in that country. In Brazil, Petrobras has signed a lease agreement with Excelerate Energy to operate the Bahia LNG import terminal, where Golar Winter FSRU is operating.

(2) Oceania

Australian Industrial Energy (AIE) concluded an FSRU charter contract with Höegh LNG for the Port Kembla terminal in New South Wales, with operations scheduled to start in mid-2023.

(3) Asia

In the Philippines, three projects are taking shape. First, FGEN LNG is constructing an FSRU terminal in the First Gen Clean Energy Complex in the Batangas region. Second, Excelrate Energy plans to build an FSRU terminal offshore Batangas, but in September 2022, the country's Department of Energy announced that it had not yet approved the construction plan. In October 2022, AG&P completed the conversion of the LNG carrier ISH into an FSU for the PHLNG (Philippines LNG) import terminal offshore Batangas, with operations scheduled for early 2023. In China, CNOOC has already installed an FSRU at the Tianjin LNG terminal in Tianjin Port. In India, Petronet LNG in November 2022 approved an investment in an FSRU terminal with an annual capacity of up to 4 Mt at the port of Gopalpur in the country's east, and is proceeding with the installation until 2026.

In Singapore, the country's regulator EMA (Energy Market Authority) announced precautionary measures to ensure energy security in October 2021, specifying a Standby LNG Facility (SLF) (security-compliant LNG inventory) to install the world's largest FSRU Bauhinia Spirit (former MOL FSRU Challenger, 263,000 m^3) is on standby (scheduled by the end of March 2023) to enhance energy security.

3-7. Example of FSU (Floating Storage Unit) Application in Japan

Although there has been no experience utilizing FSRUs in Japan so far, there is a track record of FSUs functioning as storage tanks until an onshore terminal goes into operation in Hokkaido in 2011. Specifically, JAPEX used a combination of natural gas supply from the Yufutsu oil and gas field and externally procured LNG as a stable supply measure to meet peak winter demand from November 2011 to March 2012. An ocean-going LNG carrier was chartered, moored at the pier, transshipped to a domestic vessel using the STS (Ship-to-Ship) method. This first STS-type LNG in Japan was conducted by MOL, which deployed its LNG carriers as FSUs and conducted a total of 51 STS operations (Table 3).

Table 3 LNG STS trans-shipment in Hokkaido (2011-2012)

	Ocean-going vessel	Domestic vessel
Ship, Capacity	LNG Taurus (125,000m3)	Akebono Maru (3,500m3)
Note	2011/11-2012/3, moored at the pier	Between the Yufutsu LNG receiving terminal and an ocean-going vessel moored at the pier

Source: JAPEX

4. FSRU as a de-Russian Measure by Europe

4-1. REPowerEU: European Policies to Break Away from Dependence on Russia

Table 4 European Natural Gas (PL, LNG) Imports and Sources (Bcm) (2020)

From / To	Methods	Netherlands	Norway	Other Europe	Azerbaijan	**Russia**	Iran	Algeria	Libya	United States	Qatar	Others	Total imports (Bcm)	Russia Dependency (%)
Belgium	PL	8.4	7.5	1.7	-	**-**	-	-	-	-	-	-	**17.6**	0%
	LNG	-	†	-	-	**0.9**	-	-	-	1.3	0.9	2.0	**5.1**	17%
France	PL	3.8	17.6	1.7	-	**2.6**	-	-	-	-	-	-	**25.8**	10%
	LNG	-	0.8	-	-	**5.0**	-	4.3	-	2.6	5.0	1.9	**19.6**	26%
Germany	PL	13.0	31.2	1.6	-	**56.3**	-	-	-	-	-	-	**102.0**	**55%**
	LNG	-	-	-	-	**-**	-	-	-	-	-	-	**-**	-
Italy	PL	1.6	5.4	8.4	†	**19.7**	-	11.5	4.2	-	-	-	**50.8**	39%
	LNG	-	-	†	-	**-**	-	2.8	-	2.1	-	7.2	**12.1**	0%
Netherlands	PL	-	20.0	7.2	-	**11.2**	-	-	-	-	-	-	**38.4**	29%
	LNG	-	-	-	-	**-**	-	-	-	-	-	-	**-**	-
Spain	PL	-	1.2	2.1	-	**-**	-	9.1	-	-	-	-	**12.3**	0%
	LNG	-	0.5	0.1	-	**3.4**	-	0.5	-	5.4	3.4	7.6	**20.9**	16%
Turkey	PL	-	-	-	11.1	**15.6**	5.1	-	-	-	-	-	**31.8**	49%
	LNG	-	0.1	-	-	**0.2**	-	5.7	-	2.8	0.2	5.8	**14.8**	2%
Ukraine	PL	-	-	14.7	-	**-**	-	-	-	-	-	-	**14.7**	0%
	LNG	-	-	-	-	**-**	-	-	-	-	-	-	**-**	-
United Kingdom	PL	1.0	23.7	0.3	-	**4.7**	-	-	-	-	-	-	**29.7**	16%
	LNG	-	0.4	-	-	**2.9**	-	†	-	4.7	2.9	7.6	**18.6**	16%
Other EU	PL	-	0.3	56.7	†	**55.2**	-	0.4	-	-	-	-	**112.6**	49%
	LNG	-	2.3	0.2	-	**4.7**	-	0.7	-	6.7	4.7	4.5	**23.7**	20%
Rest of Europe	PL	0.3	-	6.3	2.2	**2.5**	-	-	-	-	-	-	**11.3**	22%
	LNG	-	-	-	-	**0.1**	-	-	-	-	0.1	- †	**0.1**	100%
Total Eurpope (Bcm)	PL	28.1	106.9	100.7	13.4	**167.7**	5.1	21.0	4.2	-	-	-	**447.1**	38%
	LNG	-	4.1	0.3	-	**17.2**	-	13.9	-	25.6	17.2	36.4	**114.8**	15%
	Total	28.1	111.0	101.0	13.4	**184.9**	5.1	34.9	4.2	25.6	17.2	36.4	**561.9**	33%
Total Eurpope Ratio (%)	PL	6%	24%	23%	3%	**38%**	1%	5%	1%	0%	0%	0%	**100%**	
	LNG	0%	4%	0%	0%	**15%**	0%	12%	0%	22%	15%	32%	**100%**	
	Total	5%	20%	18%	2%	**33%**	1%	6%	1%	5%	3%	6%	**100%**	
Total Eurpope (Million-tonnes)	PL	20.7	78.6	74.0	9.8	**123.2**	3.8	15.4	3.1	-	-	-	**328.6**	
	LNG	-	3.0	0.2	-	**12.7**	-	10.2	-	18.8	12.7	26.8	**84.4**	
	Total	20.7	81.6	74.3	9.8	**135.9**	3.8	25.6	3.1	18.8	12.7	26.8	**413.0**	

Source: Compiled by IEEJ from bp Statistical Review of World Energy 2021 (†=less than 0.1)

After the invasion of Ukraine in February 2022, the EU declared a phased reduction of Russian natural gas imports, and countries in the region planned to build or expand LNG receiving terminals and introduce FSRUs. In March, the EC (European Commission) announced REPowerEU, which aims to procure an additional 50 Bcm (about 37 Mt) of LNG and 10 Bcm (about 7 Mt) of PL, and European countries will significantly reduce their dependence on Russian products, which had accounted for 38% of PL supply (Table 4).

4-2. LNG Receiving Projects in Europe

The advantages of the FSRU, which EU countries are promoting as a measure to end the use of Russian gas, include the fact that LNG imports can begin within 12 months (6 months at the earliest) after project approval if existing vessels are chartered, whereas onshore receiving terminals require a lead time of 3 to 5 years from the FID to completion. The short-term charter is also said to reduce the risk of lock-in, making it an easy-to-use method for Europe, which is pursuing a decarbonization policy in the future.

As of the end of 2021, 33 onshore terminals and 6 FSRUs were in operation in Europe, with an LNG regasification capacity of about 188 Mt/y, which accounts for about 20% of the global LNG receiving terminal capacity of 990 Mt/y (Table 5). Although the construction of LNG terminals in Europe has been stagnant in recent years, Croatia began operating an FSRU at its Krk LNG receiving terminal in 2021, and Turkey, where demand for gas power generation is growing, has also introduced an FSRU in 2021.

Table 5 Current and planned LNG receiving terminals in Europe (as of November 2022)

No.	Country	Operation			Construction / Plan		
		Onshore	FSRU	Capacity (Mt/y)	Onshore	FSRU	Capacity (Mt/y)
1	Norway	2		0.5			—
2	Sweden	2		0.6			—
3	Finland	3		0.6		1	3.8
4	Lithuania		1	2.9			—
5	Poland	1		3.7	(Expansion)		3.7
6	Germany			—	3	6	30.0
7	Netherlands	1		8.8		2	11.5
8	Italy	4	1	12.1	(Expansion)	3	13.5
9	Belgium	1		6.6	(Expansion)		6.0
10	United Kingdom	3		36.0	(Expansion)		3.8
11	France	4		25.6		1	3.7
12	Spain	7		49.2			—
13	Portugal	1		5.6			—
14	Malta		1	0.5			—
15	Croatia		1	1.9			—
16	Albania			—		1	3.5
17	Greece	1		5.1		1	5.9
18	Turkey	2	2	28.5		1	—
19	Gibraltar	1		0.1			—
20	Cyprus			—		1	1.3
	Total	33	6	188.3	7	17	86.7

Source: IEEJ

As of November 2022, European LNG buyers are expected to secure at least 17 FSRUs (Table 5, Fig. 6). These include six in Germany, three in Italy, two in the Netherlands, and one each in the other countries of France, Finland, Albania, Greece, Turkey, and Cyprus. In addition, Poland and the U.K. are also considering the project, which could bring the total number of FSRUs in Europe to more than 20. Some of the plans have substantial government support, which increases the certainty that the projects will be completed. And while each country is working to build LNG import flows, also planning future diversions to decarbonized fuels such as hydrogen and ammonia to minimize the risk of becoming stranded assets.

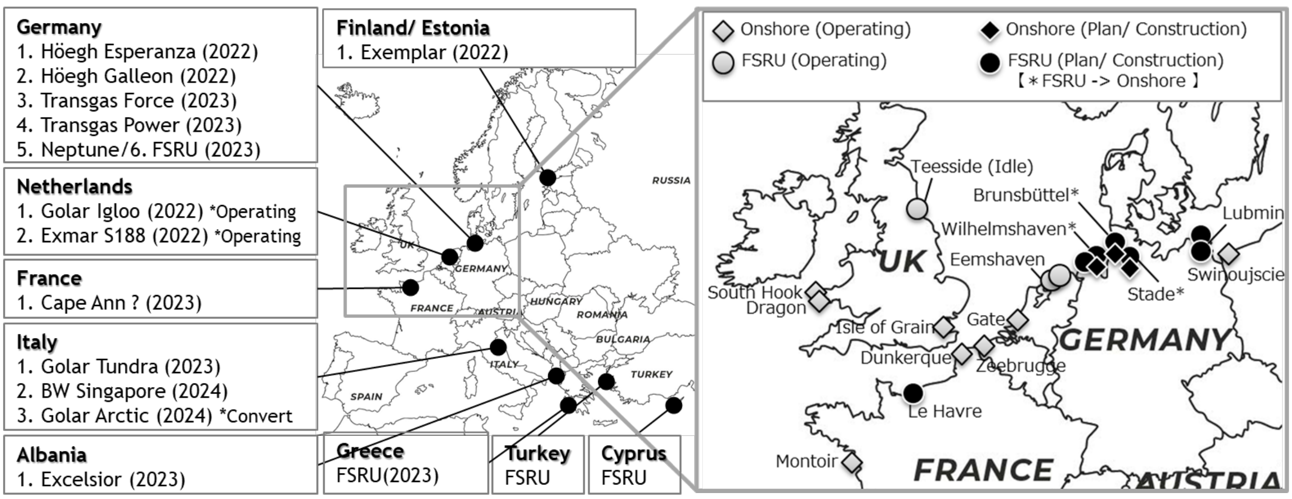

Fig. 6 New FSRU Projects in Europe

Source: IEEJ

(1) Germany

Germany has the largest LNG receiving capacity expansion plan in Europe, with 6 FSRUs (2 at Wilhelmshaven, Brunsbüttel, 2 at Lubmin, Stade) and 3 onshore terminals (Wilhelmshaven, Brunsbüttel, and Stade: to be converted from FSRUs to onshore terminals), planning to have a capacity of about 30 Mt/y, or about 40% of the country's demand. In June 2022, the country's LNG Acceleration Act came into effect, and the LNG import terminal is now under construction. The law expedited approval, bidding, and review procedures for the necessary connections for the terminal, and established exemptions from environmental impact assessments.

The government has leased five FSRUs, and has instructed RWE and Uniper to charter the vessels. Wilhelmshaven and Brunsbüttel will be operational in 2022/23, Stade at the end of 2023, Lubmin after the end of 2023, and the fifth unit will again be in service at Wilhelmshaven. A sixth unit is to be built in Lubmin by the end of 2022 by a private consortium.

The Wilhelmshaven terminal is planned by Tree Energy Solutions (TES), E.ON, and ENGIE to be operational in winter 2023 with an annual capacity of 5 Bcm. TES has also been working on a hydrogen terminal project since 2019, aiming for large-scale hydrogen import by 2025. The terminal will consist of 6 piers and 10 onshore tanks with a total capacity of 2 Mcm and a direct connection to the natural gas, hydrogen, and CO_2 pipeline network. The Stade terminal is part of the Hanseatic Energy HubHA (HEH), including Dow, Fluxys, Partners Group, and Buss Group The consortium plans to start receiving LNG from the FSRU at the end of 2023 and convert it to an onshore receiving terminal from 2026, with an annual regasification capacity of 13.3 Bcm. The Brunsbüttel terminal will be jointly constructed by KfW, Gasunie, and RWE in March 2022, with KfW investing 50% on behalf of the German government and Gasunie operating the terminal. The terminal will have an annual regasification capacity of 8 Bcm and is expected to be operational in 2026. In the future, the company plans to convert the terminal into an import terminal for green hydrogen and ammonia.

(2) Netherlands

In March 2022, EXMAR, a Belgian shipping company, signed a five-year charter contract with Gasunie of the Netherlands for the Eemshaven LNG project north of Groningen. Two FSRUs (Golar Igloo and Exmar S188) were installed at the Eemshaven LNG receiving terminal in September 2022 and started operation in a record time of only 6 months from planning to completion. The terminal is planned to be converted for green hydrogen storage in the future.

(3) Italy

In May 2022, Golar sold its existing LNG carrier, Golar Arctic, to Italy's Snam, which will convert it into an FSRU over the next two years. The vessel will be installed by Snam in the Sardinia Portovesme port area. In June, Snam purchased FSRU Golar Tundra from Golar LNG, which will be installed in the central and northern regions of Sardinia and put into service in spring 2023. In July, Snam and BW LNG signed an agreement for Snam Group to acquire FSRU BW Singapore. In October 2022, the government of Singapore instructed Snam to install and start operation of the FSRU by the end of March 2023, and there are plans to receive 5 Bcm of LNG at the Piombino port in the Toscana region. However, on October 20, local and environmental groups protested the FSRU project.

(4) France

France is considering the deployment of one FSRU at the port of Le Harvre in the northern part of the country. The project, initiated by TotalEnergies and the Ministère de la Transition écologique, could increase regasification capacity by 5 Bcm. The Cape Anne, one of the two FSRUs owned by TotalEnergies and currently in operation in China, is scheduled to be commissioned in June 2023, with commissioning scheduled for September 2023.

(5) Finland

One FSRU deployment is being considered on the country's south coast. In April 2022, the Finnish and Estonian governments announced an MOU agreeing to jointly lease an FSRU. In May 2022, Excelerate Energy and Gasgrid Finland Oy subsidiary signed a 10-year charter agreement for the FSRU, under which Excelerate Energy will deploy the FSRU Exemplar. In August 2022, Gasgrid Finland signed an agreement with Fortum to install the FSRU at its port in Inkoo in December 2022.

(6) Albania

The deployment of one FSRU is under consideration. In 2021, Excelerate Energy signed a contract with Italy's Snam and Albania's national gas company Abgaz to build a natural gas pipeline in Albania. Prior to that, Excelerate Energy signed an MOU for a feasibility study on the development of an integrated power solution, including an FSRU LNG receiving terminal at the southern port of Vlora in the country. FSRU Excelsior for the Vlora FSRU LNG project in Israel after the contract expires at the end of 2022, with plans to bring it on stream in Q2 2023.

(7) Greece

The deployment of one FSRU is under consideration. In January 2022, Greece Gastrade announced an FID for the construction of the Independent Natural Gas System (INGS) at Alexandroupolis, where the FSRU will be connected to the Greek national natural gas transportation network. The FSRU will be connected to the Greek national natural gas transportation network and the INGS is expected to be operational by the end of 2023. The regasification capacity is estimated at 5.5 Bcm.

4-3. Challenges in implementing FSRU

FSRUs can provide a rapid response to short-term increases in demand, However, there are also demand-side, supply-side, and other policy and regulatory issues to be addressed in their implementation. Therefore, it is still unclear to what extent the plan will proceed in Europe.

(1) Demand side

Many FSRU facilities are difficult to modify after construction and may not meet the specifications of the demand side (e.g., large/small tank capacity, maximum flow/pressure for regasification, open/closed seawater loop system for regasification, flexible/hard cargo hoses, and availability of LNG reload function). In addition, the profitability of an FSRU requires an annual demand of around 3 Mt/y of LNG, and in an environment such as Japan, where demand is scattered and nationwide gas pipeline connections are not yet established, it would be practically difficult to introduce an FSRU. In other countries, national companies and state-owned firms are the main players to hedge risks.

(2) Supply Side

The global shortage of shipbuilding capacity makes it difficult to rapidly increase production of FSRUs. There are also concerns about the uneven distribution of shipyard orders to China and Korea and a shortage of human resources (engineers for tank welding, crew for LNG carriers, etc.), which could lead to a short- to medium-term shortage of LNG supply and future decarbonization-oriented stagnation of fossil fuel infrastructure investment.

(3) Other environmental policies/regulations

The first issue for the introduction of FSRUs is environmental risk (regulations for each port, such as water temperature changes, sewage/drainage, noise and smoke emissions, etc.), which accounts for the largest number of risk factors. Other risk factors include maritime/weather risks (restrictions due to typhoons, high waves, storm surges, etc.), policy change risks (changes in energy policy, project owner's operational policy, etc.), and emerging country risks (delays in construction and licensing of jetties and power plants, project cancellation due to financial difficulties, etc.).

5. Conclusion

Europe, which aims both to phase out its dependence on Russia and to decarbonize in the future, is rapidly expanding FSRUs as transition infrastructure, which is highly compatible with its own strategy. Europe's sudden large-scale purchase of LNG has driven up prices to levels that make procurement difficult, forcing emerging and developing countries to return to coal and oil, threatening not only their industries but also their energy security. This will lead to delays in decarbonization, which in turn will worsen the rate of economic growth. And the possible rapid withdrawals from FSRUs and LNG envisaged for Europe in the future could lead to further market disruption. For a sustainable society, a realistic path forward is to utilize LNG as a low-carbon fuel as much as possible and gradually increase the ratio of decarbonized fuel. As Japan aims to realize a realistic energy transition in Asia, it is necessary to take the lead in showing the world " what a responsible developed country should do “.

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