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Atsushi Saigusa[*]

Abstract

In 2019, the aggregated capacity of large-scale LNG production projects that reached a final investment decision (FID) was the largest in the history. As a shift of fuels from coal and oil to natural gas is progressing, the importance of LNG as a means of transportation of natural gas is expected to increase further. In this paper, the author compares characteristics of locations and status of customer acquisition for eight LNG projects which reached an FID from October 2018 to December 2019 and outlines prospects for future LNG investment activities.

Key words: LNG, Investment, Natural Gas, FID, 2019

1. Introduction

In 2019, the aggregated capacity of large-scale LNG production projects that reached a final investment decision (FID) was the largest in the history as expected, over 70 million tonnes per annum (mtpa) from six projects. As a shift of fuels from coal and oil to natural gas is progressing, the importance of LNG as a means to transport natural gas is expected to grow further. In this paper, the author compares characteristics of locations and progress of marketing activities for eight LNG projects which reached an FID from October 2018 to December 2019 and outlines prospects for future LNG investment activities. An overview of those projects is presented in the Table.1.

Table 1   Project FIDs (October 2018 - December 2019)

Porject	FID	Location	Operator	Capacity (mtpa)	Operation
LNG Canada	2018/10	Western Canada	LNG Canada (Shell, Petronas, DGI (Mitsubishi), PetroChina, KOGAS)	14	2025
Tortue FLNG	2018/12	West Africa	BP, Kosmos Energy	2.5	2022
Golden Pass LNG	2019/02	Gulf of Mexico, U.S.	Golden Pass LNG (Qatar Petroleum, ExxonMobil)	15.6	2024
Sabine Pass LNG Train 6	2019/06	Gulf of Mexico, U.S.	Cheniere Energy	4.5	2024
Mozambique Area 1 LNG	2019/06	East Africa	Mozambique LNG 1 (Total, etc..)	12.88	2024
Calcasieu Pass LNG	2019/08	Gulf of Mexico, U.S.	Venture Global	10	2022
Arctic LNG 2	2019/09	Arctic Russia	NOVATEK	19.8	2023
Nigeria LNG Train 7	2019/12	Western Africa	NLNG (NNPC, Total, Shell, Eni)	7.6	2024

2. LNG projects Overview

2-1. LNG Canada (FID: October 2018)

The LNG Canada project originally emerged in 2012 and at that time had a target to reach an FID by 2016. However, the

[*] Researcher, Gas Group, Fossil Energies & International Cooperation Unit, The Institute of Energy Economics Japan

project activity was temporarily suspended in July 2016 due to unfavorable price conditions from 2015. Thereafter, with recovering LNG and oil prices, project activities resumed. Petronas, which canceled another LNG project in Western Canada in May 2018, joined the joint venture, which reorganized share distribution among parties and reached an FID in October 2018.

Produced LNG will be offtaken by the equity partners on pro rata basis. This arrangement is known as "equity lifting". The LNG Canada joint venture does not have sales- and- purchase contracts with LNG consumers directly, unlike traditional LNG projects based on sales- and- purchase contracts. The shareholders of the LNG Canada projects are: Shell (40%); Petronas (25%); DGI (15%); PetroChina (15%); and KOGAS (5%).

DGI, a wholly owned subsidiary of Mitsubishi Corporation, has signed sales- and- purchase contracts with Tokyo Gas, Toho Gas and JERA with volumes provided from LNG Canada.

This project is located on the West Coast of North America. This yields an advantage in transportation because there is no choke point in the route and the distance is relatively short to the Asian market which is expected to have even greater demand in the future. This project was the first greenfield large-scale project that reached an FID after the Yamal LNG project in 2013.

Table 2   Partners of LNG Canada

Investor	Offtake (mtpa)	Share
Shell	5.6	40%
Petronas	3.5	25%
DGI (Mitsubishi)	2.1	15%
PetroChina	2.1	15%
KOGAS	0.7	5%

Table 3   DGI's Sales and Purchase Contracts

Buyer	Period	Volume (mtpa)	Notes
JERA	15	1.2	2024- DES
Tokyo Gas	13	0.6	2026- DES
Toho Gas	15	0.3	2026- DES

2-2. Greater Tortue Ahmeyim FLNG (FID: December 2018)

The Greater Tortue Ahmeyim project offshore West Africa selected a floating LNG (FLNG) vessel as its liquefaction facility. In some cases, FLNG could reduce initial cost compared to an onshore plant. Natural gas produced from the offshore gas field will flow into the FLNG and will be liquefied in the offshore vessel. Kosmos Energy discovered the gas field in 2015. BP joined the project in 2016 and reached an FID for an LNG export project in December 2018.

BP Gas Marketing will be the sole offtaker of the project. This is similar to LNG Canada in a sense that there is no sales and purchase contract with consumers directly. BP will sell the volumes from the project as part of its portfolio. Construction period is expected to be relatively short and the project is expected to start operation in 2022.

The project is located offshore West Africa and close to Europe where countries have been increasing import of LNG recently.

2-3. Golden Pass LNG (FID: February 2019)

Golden Pass LNG plans to liquify and export natural gas from the Permian Basin, that has huge reserves of natural gas and continues producing a large volume of natural gas, including associated gas production. The Golden Pass site had been originally developed as an LNG receiving terminal. As the shale revolution has changed the gas market dramatically, significant import of LNG is no longer needed. Therefore, the owners have intended to convert their LNG import infrastructure to export infrastructure

utilizing existing facilities such as LNG tanks. Some other LNG export projects in the United States also have been developed in the same manner. The Golden Pass export project was initiated in 2012 by applying an export license to Department of Energy (DOE). They have obtained all necessary regulatory permits and reached an FID in February 2019.

The project is funded by two LNG giants, Qatar Petroleum and ExxonMobil, and does not have sales and purchase contracts with consumers directly. Ocean LNG, a joint venture of Qatar Petroleum and ExxonMobil, will be the sole offtaker of the project.

The project is located on the Gulf of Mexico, Texas. There is no choke point in the ocean transportation route to the European market. Meanwhile for transportation to the Asian market, the shippers will have to pay higher transportation costs than transportation to Europe because the distance from the Gulf region to the Asian market is relatively long. In addition, the shippers will have to transit through the Panama Canal. The expansion of the canal was completed in 2015.

2-4. Sabine Pass LNG Train 6 (FID: June 2019)

Sabine Pass LNG has already five liquefaction trains operating at the site. The operator Cheniere is developing a sixth train. The company had developed its earlier projects with traditional financing arrangements, creating a foundation by securing multiple long-term offtake contracts. Train 6 has already signed a deal with Petronas providing 1.1 mtpa for 20 years. Any excess capacity not sold under long-term contracts is available for Cheniere's integrated marketing function to sell into the global market.

This project is located on the Gulf of Mexico, Louisiana. The characteristic of location is the same as Golden Pass LNG.

2-5. Mozambique Area 1 LNG (FID: June 2019)

Mozambique Area 1 LNG has attracted attention as a large-scale project comparable with LNG Canada. Anadarko discovered a gas field offshore of Mozambique in 2010, initiating the LNG project. The project joint venture reached an FID in June 2019 after they signed its first sales and purchase contract with Électricité de France (EDF) in February 2018, and other many customers later, for aggregated volumes equivalent to about 90% of capacity. The project created its financial foundation by making traditional offtake contracts. However, those contracts have some new features such as using European gas prices index, no destination restriction, and flexible cooperation between two companies.

The project is located on the East Coast of Africa, Mozambique. This will be the first onshore LNG production facility in the region. As the location is close to India and other South Asian countries, the project joint venture has negotiated deals with Asian consumers. JERA, Tokyo Gas, Tohoku Electric Power of Japan, CNOOC of China, CPC of Chinese Taipei, Bharat Petroleum of India, and Pertamina of Indonesia have signed sales and purchase contracts with the Mozambique joint venture. Furthermore, the location is also suitable to transport LNG to Europe via Suez Canal or Cape of Good Hope. EDF and Centrica signed contracts, too. The good location for transportation is one of the reasons enabling many contracts.

Table 4   Long-Term Contracts by Mozambique Area 1 LNG

Buyer	Period	Volume (mtpa)	Notes
EDF	15	1.2	
Tohoku Electric Power	15	0.28	DES
CNOOC	13	1.5	
Tokyo Gas / Centrica	- early 2040s	2.6	Flexible offtake between two companies
Shell	13	2.0	
Bharat Petroleum	15	1.0	
Pertamina	20	1.0	
JERA / CPC	17	1.6	DES, No destination restriction

2-6. Calcasieu Pass LNG (FID: August 2019)

Calcasieu Pass LNG is a sole greenfield project of this report in the United States, promoted by Venture Global, a new entrant to the LNG industry. This project was started in 2014 by applying to DOE. This plant will install modular liquefaction trains (constructing smaller trains on the offsite and assembling at the onsite) to reduce initial and running costs. Venture Global signed sales and purchase contracts with some European consumers to create financial foundation.

The project is located on the Gulf of Mexico, Louisiana. The characteristic of location is same to Golden Pass LNG.

Table 5   Long-Term Contracts by Calcasieu Pass LNG

Buyer	Period	Volume (mtpa)	Notes
Shell	20	1.0	HH linked pricing
Edison	20	1.0	
Galp	20	1.0	
BP	20	2.0	
Repsol	20	1.0	
PGNiG	20	1.0	FOB

2-7. Arctic LNG 2 (FID: September 2019)

Arctic LNG 2 is promoted by Russian independent NOVATEK, as its second LNG project in the Arctic region.

The project is developed in an "equity lifting" format similar to LNG Canada, with volumes of LNG offtake to be distributed based on the share of investment. The shareholders are NOVATEK (60%), Total (10%), CNPC (10%), CNNOC (10%), and Japan Arctic LNG (10%). NOVATEK has signed sales and purchase contracts with Repsol and Vitol, 1 mtpa each for 15 years.

The project is located in the Russian Arctic region which is relatively close to Europe. NOVATEK's first Arctic LNG project, Yamal LNG, has been providing much LNG to Europe since it started operation at the end of 2017. Arctic LNG 2 is expected to operate in a similar manner as Yamal LNG. NOVATEK plans to develop LNG transshipment terminals to transfer cargoes from ice-class LNG carriers to conventional LNG carriers to optimize ship operation. NOVATEK also plans to increase the Arctic marine route (Northern Sea Route, or NSR). An LNG carrier, through the Bering Strait after NSR, could reach the Asian market much faster than otherwise.

Table 6   Shareholders of Arctic LNG 2

Investor	Offtake (mtpa)	Share
NOVATEK	12.0	60%
Total	2.0	10%
CNPC	2.0	10%
CNOOC	2.0	10%
Japan Arctic LNG	2.0	10%

2-8. Nigeria LNG Train 7 (FID: December 2019)

Nigeria LNG has six liquefaction trains operating at the site. The expansion project will develop a seventh train. Nigeria, one of the traditional oil and gas producers, has provided LNG to Europe, which is relatively close to Nigeria. The planned nominal capacity of Train 7 itself is 4.2 mtpa. The project also plans to improve efficiency of the existing facilities (debottlenecking), leading to the total additional capacity of 7.6 mtpa in the project.

Customers' identities of the Train7 project haven't been revealed yet.

3.　Projects with Anticipated FIDs

Table 7 indicates the list of projects that are anticipated to reach FIDs after 2020. The aggregated capacity of those projects is about 270 mtpa, which represents 86% of 313 mtpa of LNG traded in the world in 2018.

Table 7. Projects with Anticipated FIDs after 2020

Project	Capacity (mtpa)
Driftwood LNG	27.6
Plaquemines LNG	20.0
Gulf LNG	10.0
Texas LNG	4.0
Lake Charles LNG	16.45
Corpus Christi LNG Stage III	9.52
Port Arthur LNG	13.5
Rio Grande LNG	27.0
Freeport LNG Train 4	5.0
Delfin FLNG	13.0
Cameron LNG Trains 4, 5	10.0
Annova LNG	6.0
Magnolia LNG	8.0
Jordan Cove LNG	7.8
Energía Costa Azul LNG	2.4
North American Pacific LNG	3.0
Woodfibre LNG	2.1
Goldboro LNG	10.0
Bear Head LNG	8.0
Qatargas LNG Expansion	49.0
Rovuma LNG (Area 4)	15.2
Djibouti FLNG	3.0
Etinde FLNG	1.3

4.　Comparison with Past Projects

4-1. Liquefaction Capacity Sanctioned

In 2019, the aggregated capacity of FID LNG production projects was the largest in the history.

During 2011 to 2015, the average of the aggregated capacity of FID LNG production projects in a year was about 30 mtpa. But in 2016 and 2017, it was below 10 mtpa. At that time, plunging LNG prices along with oil prices turned producers negative toward FIDs. In fact, as mentioned above, the LNG Canada partners once postponed their schedule of FID in 2016. This may have caused tightness of LNG supply in early 2020 where production expansion couldn't catch up with expected demand growth.

The anticipated potential tightness may have given producers optimistic ideas that it would be easy to attract customers to future LNG production projects.

The recovery of oil prices in 2017 and 2018 was another reason. As most of existing long-term LNG sales and purchase contracts are linked with oil prices, LNG prices are still heavily affected by oil prices. Although oil indexation tends to decrease in new LNG contracts, it is still significant. After Brent recovered from USD 30/bbl in January 2016 to USD 80/bbl in October 2018 gradually, it was stable at USD 60 USD 70/bbl during 2019.

4-2. Financing of LNG Production Projects

Project funding has been diversified from previous projects, as a result of the changing market conditions such as increasing demand and spot trading.

As a traditional way of project development, securing long-term sales and purchase contracts with end-use customers had been a significant milestone to reach an FID. However, portfolio players such as BP, Shell, Total and ExxonMobil or giant NOCs such as Qatar Petroleum, Petronas do not necessarily need LNG sales contracts to proceed their LNG production projects. Because they have numerous own LNG supply sources and different customers all over the world, they have thought that they can sell their LNG volumes through their portfolios. Figure 1 expresses each project's status of customer acquisitions at the point of FIDs in 2019 and 2009-2010. In 2019, while share of contracts with end-use customers was relatively low, shares of contracts with portfolio players or no contract cases were remarkable.
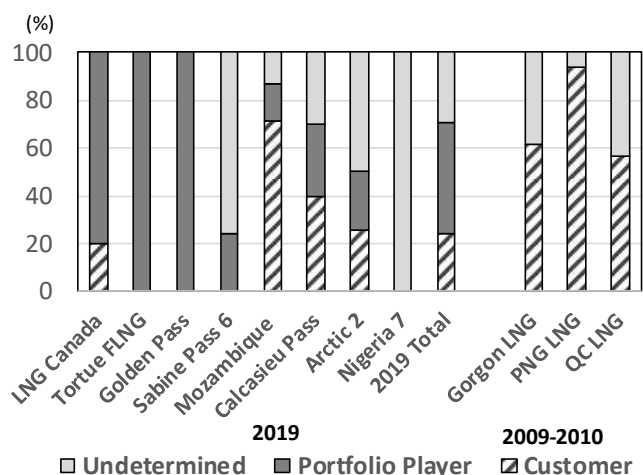

Fig. 1   Status of Customer Acquisition at FID Point

Spot and short-term contract volumes represented 34% of the total LNG traded in the world in 2019. Increasing liquidly and flexibility of LNG transportation has made spot trading and portfolio players so active. While it is important to acquire customers for an LNG production project to proceed by following a traditional idea, the current over-supply capacity conditions make it difficult to acquire customers without flexibility, transparency, stably operation and other attractive conditions.

Figure 2 shows capacity control over liquified facilities by selected companies. Both portfolio players and NOCs have expanded their shares and is expected strengthen influences in the market further.

As a different example, Driftwood LNG promoted by Tellurian is offering customers LNG volumes packaged with Tellurian Holdings stocks. Tellurian Holdings has its own exploration and development company and pipelines, LNG facilities. Customers can use Tellurian Holdings's feedgas and infrastructure to reduce various costs.
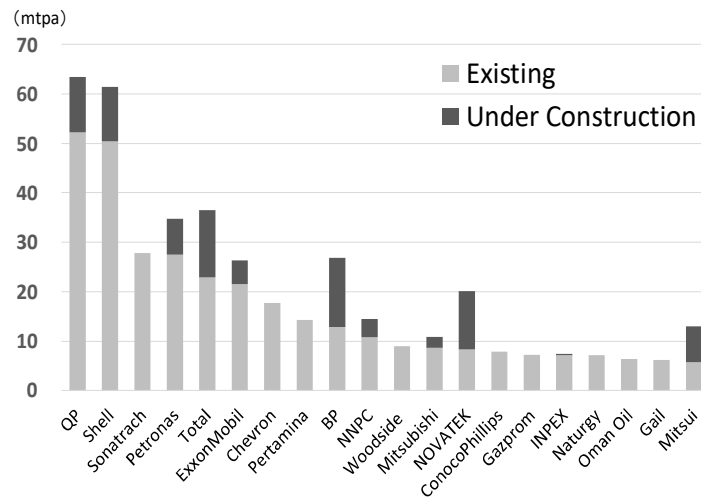
Fig. 2   LNG Supply Capacity Control Held by Companies

4-3. Project Development Lead Time

Lead times of new projects from initial ideas, to FIDs and commercial operations are also different by project. A project with traditional development model like Mozambique Area 1 LNG starts from exploring and developing gas field, having a long lead time from planning to commercial operation, with higher total initial cost and requirement to secure foundation customers, as well as potential delay in development.

Those LNG production projects which utilize grid gas, including shale gas, as feedgas in the United States, do not need to explore and develop their own dedicated gas fields. Those LNG production projects that plan to convert existing LNG receiving terminals, such as Golden Pass, already have some facilities and only have to construct liquefaction facilities, berths, and additional pipelines if needed. Therefore, they need relatively shorter lead time than traditional greenfield projects and reduce construction costs. This is also the case for other brownfield projects such as Sabine Pass. And, portfolio players do not need to secure customers for individual projects before FIDs, and they can flexibly change their project schedules and promptly make investment decisions.

4-4. Reducing Construction Cost

Reducing construction cost is very important. This could have a direct influence over offering LNG prices and project funding. The emerging FLNG concept has had significant impact on upstream development. Some offshore gas fields with relatively small reserves or far from shore can be profitably developed with low initial cost through high versatility of FLNG. Shorter construction period than onshore plants is another reason to be considered as an option. Although FLNG has some demerits of adapting to onsite environment or inability to expand capacity, the number of projects to be considered for FLNG development is expected to increase in the future.

Some projects, including Driftwood LNG, Calcasieu Pass LNG, Venture Global Plaquemines LNG, and Corpus Christi LNG Stage III, are planning to install many small modular liquefaction trains that have small capacity of around 1 mtpa. Those modular trains constructed at offsite factories will be assembled at the onsite. They can reduce amount of onsite work and their initial costs by using modular trains.

5.   Future Prospect

Currently, most of LNG production projects that are anticipated to reach FIDs soon are concentrated in the Gulf of Mexico region, United States. As U.S producers have sold much of LNG under Free on Board (FOB) contracts, they are expected to improve LNG market's liquidly. If those all anticipated projects proceed as scheduled, U.S LNG production capacity will

skyrocket and will catch up or surpass those of Qatar and Australia. The Federal Energy Regulatory Commission (FERC) plans to install a new office specialized in LNG projects in Houston to meet many applications.

However, there are some doubts that all proposed projects will proceed as scheduled. As some projects do not have enough sales and purchase contracts to underpin their financing, they may postpone their FID schedules. Diversified LNG producers have to compete with each other, reducing initial or running cost, optimizing transportation to beat their competitors and to acquire customers. At this point, portfolio players have strong advantages as they already have various LNG facilities and many kinds of customers. New entrance companies must have different advantages which existing companies do not have, which is a key to successful development. Furthermore, the historically low spot LNG prices are another concern. Plunging LNG prices along with oil prices discouraged LNG project developers to reach FIDs in 2016 and 2017. The current low spot LNG prices are a factor that reduces the buyer's desire to conclude long-term purchase contracts, which may hinder progress of LNG production projects. In addition, it may be difficult for LNG project developers to secure EPC contractors when multiple huge projects are in progress simultaneously. There are only a few EPC contractors that can take care of large-scale LNG production projects, and there is a concern over rising construction costs, rising labor costs and delays in project implementation.

If all anticipated projects proceed as scheduled, LNG production capacity will increase rapidly in not only in the United States but also all over the world. There may be over supply situations depending on how demand develops. Effort to expand demand, such as investment on the demand side and market development, are also required to ensure customers. Notably, the United States has had the trade problem with China, where LNG demand is expected to increase significantly.

According to "The Role of Gas" published by the IEA (International Energy Agency) in July 2019, natural gas is positioned as an energy source that plays a role in various sectors, and switching from more polluting fuels to natural gas is very important. However, it states that natural gas is not a solution to long-term climate change. In addition, energy used for liquefaction of natural gas is also regarded as a problem. Some LNG producers have plans to procure all energy used in their LNG facilities from renewable energy sources. Climate change measures may limit the growth of gas demand in developed countries, especially in Europe. On the other hand, in emerging countries in Asia, whether natural gas can be introduced instead of coal is an important factor in climate change policies. It is necessary to diversify LNG supply sources, improve liquidity in transactions and enhance price competitiveness in order to have LNG play an important role. More investment will be needed to achieve those objectives.

Reference

1)   " Survey on LNG Trade",   June 2017,   (Chapter 2 pp. 31 - 38),   Japan Fair Trade Commission

2)   "The LNG Industry ANNUAL REPORT 2020",   April 2020,   (Pages 6 - 7),   GIIGNL

3)   "The Role of Gas",   August 2019,   (Pages 4 - 45),   IEA

Feasibility Study on Synthetic Methane
Using an Electricity and City Gas Supply Model

Takashi Otsuki[*]**, Yoshiaki Shibata**[**]

Abstract

Methane synthesis, or methanation, is attracting much attention in the context of sector integration and climate change mitigation. This study presents a techno-economic assessment on synthetic methane in Japan employing an electricity and city gas supply model. This model, formulated as a linear programming problem, explicitly considers a carbon recycling system, including carbon capture, water electrolysis and Sabatier reaction process. The electricity sector in this model is temporally disaggregated, balancing hourly consumption and supply for a year, to incorporate the intermittent output of solar and wind power (Variable Renewable Energy = VRE). Simulation results imply that to accelerate the use of synthetic methane, it would be crucial to reduce the cost of renewables combined with a high carbon price, such as 75% cost reduction of VRE (from the level in 2014) and 750 US$/tCO$_2$. The results also imply that a significant amount of VRE capacity would be necessary to decarbonize both sectors, which would pose grid operation and social (such as land-use) challenges.

Key words: Synthetic methane, Carbon recycling, Variable renewables, Water electrolysis, Carbon price

1.   Introduction

Amid the debate on which path to take for easing climate change, "carbon recycling" is being proposed as a means for decarbonization.1) Carbon recycling is an approach which aims to achieve the cyclical use of CO$_2$ by treating it as a natural resource, namely by separating and capturing CO$_2$ from power plants, industrial plants, the atmosphere, etc. and sequestering or recycling it as a raw material or fuel. One method of carbon recycling is methane synthesis. As methane is the main component of natural gas and city gas, methane synthesis is raising hopes for the effective use of existing energy supply infrastructure (LNG tankers, city gas pipelines, gas-fired thermal power plants, etc.), sector integration of the electricity and city gas sectors through water electrolysis, and decarbonization. Furthermore, methane synthesis using hydrogen from domestic renewable energy would help improve Japan's energy self-sufficiency ratio, though the amount of hydrogen output may vary depending on the climate and other natural conditions. Despite such expectations, however, there have been few feasibility studies on introducing methane synthesis. This study developed an optimization model that treats the electricity and city gas sectors of Japan collectively, and conducted a quantitative assessment of the economic rationality and conditions for introducing a carbon recycling system consisting of CO$_2$ capture, water electrolysis, and methane synthesis. Specifically, the study performed a sensitivity analysis of carbon tax rates and solar and wind power costs, and considered the levels necessary for introducing large amounts of synthetic methane.

2.   Method of study
2-1. Overview of the model

This study developed a multiregional, high time-resolution, and optimized electricity and city gas supply model for Japan. The model is a single-year model which calculates the cost-optimized power mix and city gas mix[1] (imported natural gas or synthetic methane) for a given electricity and city gas demand. Nine target regions were identified based on the present electricity supply areas of Japan (Hokkaido, Tohoku, Tokyo, Chubu, Hokuriku, Kansai, Chugoku, Shikoku, Kyushu, and Okinawa). The time

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[*] Researcher, New and Renewable Energy Group, Electric Power Industry & New and Renewable Energy Unit, Energy and Economic Analysis Group (EEA), Energy Data and Modelling Center (EDMC), The Institute of Energy Economics, Japan

[**] Senior Economist, Manager, New and Renewable Energy Group, Electric Power Industry & New and Renewable Energy Unit, The Institute of Energy Economics, Japan

[1] City gas can contain methane, ethane, propane, and butane, but only methane is considered in this report for simplicity.

resolution was set to one hour (8,760 one-hour slots per year), and fluctuations in solar and wind power output, operation of the water electrolysis equipment, and timing of CO_2 generation from power generation were explicitly considered. The details of the formula are not included here due to lack of space.

The flows in the model are outlined in Fig. 1 (those related to CO_2 are indicated in red). In the model, the supply-demand balance of electricity, hydrogen, methane, CO_2 from electricity, and CO_2 from industry is secured in the 8,760 time slots of a year. Fourteen types of power generation-related technologies (solar, wind power, hydropower, nuclear, coal-fired thermal, oil-fired thermal, gas steam, combined cycle gas turbine, hydrogen turbine, fuel cell, pumped storage hydropower, battery, inter-regional transmission, and intra-regional distribution), two hydrogen production and storage technologies (water electrolysis and compressed hydrogen tank), three sources of methane supply (imported LNG, methanation, and intra-regional distribution), and CO_2 capture in the electricity and industrial sectors and direct air capture (DAC) were taken into consideration. As for the inter-regional exchange of energy, only electricity was incorporated into the model (inter-regional transport of hydrogen, methane, and CO_2 were not considered). Only onshore wind power was considered for wind power.
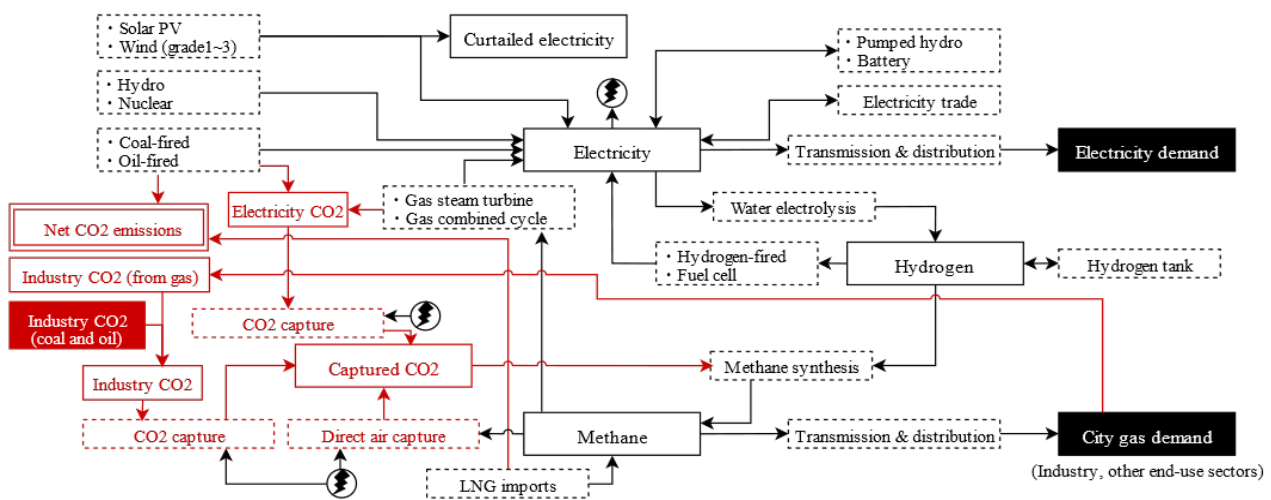

Fig. 1   Overview of the flows of energy and CO_2 of the electricity and city gas supply model

Table 1   Assumptions for the power generation and storage technologies

a. Thermal power plants

	Coal-fired	CCGT	Gas ST	Oil-fired	Nuclear	H₂ turbine	Fuel cell
Construction cost [US$/kW]	2500	1200	1200	2000	4297	1200	2500
Lifetime [year]	40	40	40	40	40	40	20
Annual O&M cost rate	0.03	0.02	0.02	0.03	0.04	0.02	0.01
Fuel cost [US$/toe]	136	LNG import price: 396; Synthetic methane cost is determined endogenously		592	19	H₂ cost is determined endogenously	
Efficiency	0.41	0.56	0.42	0.39	1.00	0.56	0.50
Own consumption rate	0.06	0.02	0.02	0.05	0.04	0.02	0.02
Availability	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Maximum ramp-up rate	0.26	0.44	0.44	0.44	0.00	0.44	
Maximum ramp-down rate	0.31	0.31	0.31	0.31	0.00	0.31	
Minimum output rate	0.30	0.20	0.20	0.30	0.80	0.20	

b. Renewables

	Hydro	Solar	Wind 1~3
Construction cost [US$/kW]	6400	2940	2840
Lifetime [year]	60	20	20
Annual O&M cost rate	0.01	0.01	0.02

c. Storage

	Pumped	Battery
Construction cost [US$/kWh]	230	170
Lifetime [year]	60	15
Annual O&M cost rate	0.01	0.01
Cycle efficiency	0.70	0.85
Self-discharge rate	0.0001	0.001
KWh/kW ratio	6	6

2-2. Major assumptions

(1) Demand for electricity and city gas

The necessary assumptions for the electricity and city gas demand for each region and hour were set in the model as follows. First, as the annual demand for electricity and city gas in the entire Japan, the 2040 values from the Sustainable Development Scenario (SDS) of the IEA's World Energy Outlook 2018[2] were used for reference. This equals an electricity demand of 927 TWh/year and a city gas demand of 29 Mtoe/year. Then, these values were allotted to each prefecture in proportion to the size of actual demand[3], to set the annual demand for each of the model's nine regions. Last, the electricity demand was broken down into hourly values based on the load curve for FY2017. The city gas demand was assumed to be constant year-round as an hourly

demand curve data was unavailable.

(2) Power generation and storage technologies and inter-regional transmission lines

The assumptions for power generation and storage technologies are described in Table 1. The construction cost, lifetime, operation & maintenance (O&M) cost, generation efficiency, on-site consumption rate, and output adjustment capability were determined by referring to the Ministry of Economy, Trade and Industry[4] and Sugiyama[5], and the same values were applied to all regions (exchange rate: US$1 = 100 yen; generation efficiency and the amount of heat of a fuel are expressed on a low calorific value basis). The construction cost for a 2014 model plant[4] was adopted as the unit construction cost. The construction cost for solar and wind power plants may decrease in the future, and therefore the assessments in this study factored in possible future cost reductions, as shown in Section 2-3.

Table 2   Assumptions for water electrolysis and the compressed hydrogen tank

	Electrolyzer	Hydrogen tank
Construction cost	700 US$/kW	700 US$/kW for compressor; 15 US$/kWh for storage tank
Lifetime [year]	20	15
Annual O&M cost rate	0.01	0.01
Efficiency	0.70	0.9 (cycle efficiency)

Table 3   Assumptions for methane synthesis

		CH_4 synthesis
Annualized construction cost [US$/(toe/year)]		100
Input	Hydrogen [toe]	1.2
	CO_2 [tCO_2]	2.3
	Electricity [MWh]	0.37

Table 4   Assumptions for the CO_2 capture equipment

		CO_2 capture		Direct Air Capture
		Power plant	Industry	
Annualized construction cost [US$/($tCO_2$/year)]		42	42	195
Input	Electricity [MWh/tCO_2]	0.22	0.22	0.37
	Methane [toe/tCO_2]	--	--	0.125

The fuel costs were set based on the 2040 values of the IEEJ[6], and the loss from intra-regional distribution was estimated at 7.6%. For the installed capacity of each power generation and storage technology, the actual 2016 value was adopted as the lower limit and was determined through optimization calculation, except for hydropower, nuclear, and pumped-storage hydropower. The installed capacities of hydropower, nuclear, and pumped-storage hydropower were set to their FY2016 capacities. Nuclear power was assumed to be operable.

The output waveform for solar and wind power (hourly values) for major cities in each region was derived from the reference source[7]. Wind power was divided into three resource grades (G1–G3), each with a different capacity factor and amount of resource. The resource grades were defined as follows: G1 has a capacity factor of 20% or lower, G2 has 20–30%, and G3 has 30% or more. The amount of resource for each grade was set according to the data from the Ministry of the Environment[8].
The installed capacity of inter-regional transmission lines was set to the actual value for 2016[9] (external variables) for all lines. Various factors must be taken into account regarding the operation of inter-regional transmission lines, such as maintaining heat capacity and frequency and synchronous stability, but in this study, the upper limit of operational capacity was capped based on OCCTO[9].

(3) Hydrogen production and storage technologies

The assumptions for water electrolysis and compressed hydrogen tank were set based on FCHJU[10] and Komiyama[11] (Table

2). The formula for the compressed hydrogen tank in this model is set separately for the compressor and the storage tank. The ratio of installed capacity of those components is determined through optimization calculations.

(4) Methane synthesis

The Sabatier reaction process was adopted as the methane synthesis process. This is a chemical reaction which produces 1 Nm_3 of methane and 2 Nm_3 of water by combining 4 Nm_3 of hydrogen and 1 Nm_3 of CO_2 under high temperature and pressure using a catalyst. As 0.32 kWh of auxiliary machine power is required to produce 1 Nm_3 of methane[12], producing 1 toe of methane requires 1.2 toe of hydrogen, 2.3 tCO_2 of CO_2, and 0.37 MWh of auxiliary machine power (Table 3). A cost of 100 US$/(toe/year) was obtained through conversion into calorific units, based on an estimated construction cost of 500,000 yen/(Nm_3-CH4/hour[12]) and an annual expense ratio of 15%.

(5) CO_2 separation and capture technologies and CO_2 from the power generation and industrial sectors

For CO_2 capture in the power generation and industrial sectors, only post-incineration capture was considered for simplicity, and facility cost and power consumption were set based on RITE[13] (Table 4). We referred to Keith[14] for setting DAC and selected natural gas as the source of heat for the calcination process.

For the power generation sector, the amount and timing of CO_2 generation are determined endogenously based on thermal power plant operation. Meanwhile, as this model is an electricity and city gas supply model, it cannot track the CO_2 from coal and oil in the industrial sector. Therefore, this assessment calculated the amount of CO_2 emissions based on the coal and oil consumption for 2040 presented in the Sustainable Development Scenario (SDS) of the World Energy Outlook 2018[2] and used the estimate as input (85 MtCO_2/year, the solid red box in Fig. 1). Hourly emissions were considered to be constant throughout the year. Further, steel and cement businesses of the industrial sector were handled together with all the other businesses in the sector in this assessment.
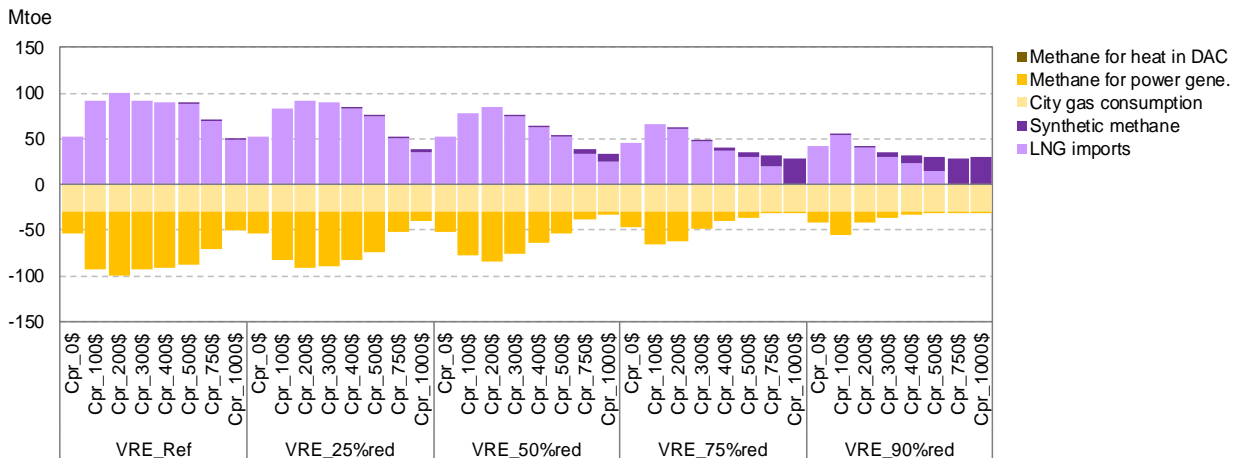

Fig. 2   Annual nationwide supply and demand for methane in Japan

(Note) Positive figures represent methane supply and negative figures methane consumption. For reference, 101 Mtoe of LNG was imported in 2018.

DAC stands for Direct Air Capture.

2-3. Case setting

This study conducted a sensitivity analysis using unit construction cost and carbon taxes of solar and wind power (variable renewable energy, or VRE) to clarify the conditions for methane synthesis to be superior in terms of cost. As the power generation cost is the dominant factor in the cost structure (Appendix) for methane synthesis by water electrolysis, VRE cost was selected as the target for sensitivity analysis. Specifically, five kinds of unit VRE construction cost (the cost for a 2014 (current) model plant, a reduction of 25%, 50%, 75%, and 90%) and eight carbon tax rates (0, 100, 200, 300, 400, 500, 750, and 1000 US$/t$CO_2$)

were prepared, producing 40 cases in total (5×8). In setting the unit VRE construction costs, the values for solar and wind in Table 1 were reduced by the same amount. Hereafter, the cases are named such that the case with the present unit VRE construction cost is named VRE_Ref, the one with a 25% reduction is named VRE_25%red, and so on. For the carbon tax rates, the case with no carbon tax is named Cpr_0$, the case with a tax of US$100 as Cpr_100$, and so on. Note that the carbon tax rates are imposed on the net CO_2 emissions from the power generation and city gas sectors (the double red-lined box in Fig. 1 which represents the carbon in the fuel for coal- and oil-fired thermal power plants and imported LNG). The model was designed so that the tax rates would not be applied to the CO_2 recycled as synthetic methane.

3. Simulation results

3-1. Introduction of synthetic methane capacities

Figure 2 shows the annual new supply of methane for all cases. It implies that a significant reduction in the unit VRE construction cost as well as a considerably high carbon tax may be required for introducing synthetic methane in large quantities. For VRE_Ref and VRE_25%red, synthetic methane capacity was limited even with Cpr_1000$. For purposes of comparison of carbon prices, under the scenario with a stable atmospheric CO_2-equivalent concentration of 450–480 ppm, the median tax rate is estimated at 200–300 US$/tCO_2 in 2050 for multiple models[15]. 1000 US$/tCO_2 is considerably higher than that level, and it is assumed that the high cost of VRE becomes a cost disadvantage for water electrolysis, preventing the Sabatier reaction process, which uses the hydrogen produced with VRE, from gaining sufficient cost competitiveness.

Meanwhile, synthetic methane grew for Cpr_750$ and above for VRE_75%red and for Cpr_500$ and above for VRE_90%red. For example, for the combination of VRE_90%red with Cpr_1000$, synthetic methane output reached 29.4 Mtoe and covered the entire demand for city gas. In Fig. 3, which shows the weighted average generation cost of VRE (obtained by dividing the sum of the generation costs for solar and wind power by their combined power output), the figures decreased to as low as 41–59 US$/MWh for VRE_75%red and to 18–24 US$/MWh for VRE_90%red. A carbon tax rate of US$500 or US$750 per tCO_2 is still high, but synthetic methane capacity might expand if the cost of VRE generation goes down to similar levels. Meanwhile, Fig. 3 shows that the weighted average generation cost may change suddenly depending on the carbon tax rate (as between Cpr_100$ and Cpr_200$ under VRE_Ref). This is because the composition of VRE changed significantly due to the introduction of wind power.

For all cases, CO_2 from the industrial sector was selected as the raw material for methane synthesis. CO_2 from the power generation sector and direct air capture were not used for any case. In the power generation sector, CO_2 supply apparently became harder to secure as the carbon tax rate went up and VRE increased (Section 3.2). Furthermore, the amount of CO_2 reused in this assessment was at most 68 MtCO_2 per year (in the case with VRE_90%red and Cpr_1000$), an amount that could be covered comfortably with industrial sector CO_2, presumably resulting in DAC not being introduced. However, it must be noted that industrial sector CO_2 is treated generically in this report; it may be difficult to capture CO_2 for some sectors or industrial plant sizes, and the industrial sector's capability to capture CO_2 requires detailed reviews in the future. DAC may become necessary if the supply of industrial sector CO_2 becomes insufficient.

3-2. Trends in the power generation sector

Figure 4 shows the total power output of Japan and Fig. 3 shows its total installed capacity. These figures indicate that solar power increases as the cost for VRE decreases and the carbon tax rate increases. Wind power also increased but not such that its effect on Japan as a whole was significant. This assessment does not consider any enhancement of inter-regional transmission lines, and this may have limited the introduction of new resources for wind power which are highly concentrated in certain regions.

In the cases where large amounts of methane synthesis were introduced (three cases, namely Cpr_1000$ with VRE_75%red, and Cpr_750$ and Cpr_1000$ with VRE_90%red), the total power output far exceeded the power demand (Fig. 4). This is because of the power required for producing hydrogen (water electrolysis), which amounted to 588–608 TWh per year. This also

applies to installed capacity (Fig. 3), resulting in solar power capacity being required for producing hydrogen in addition to
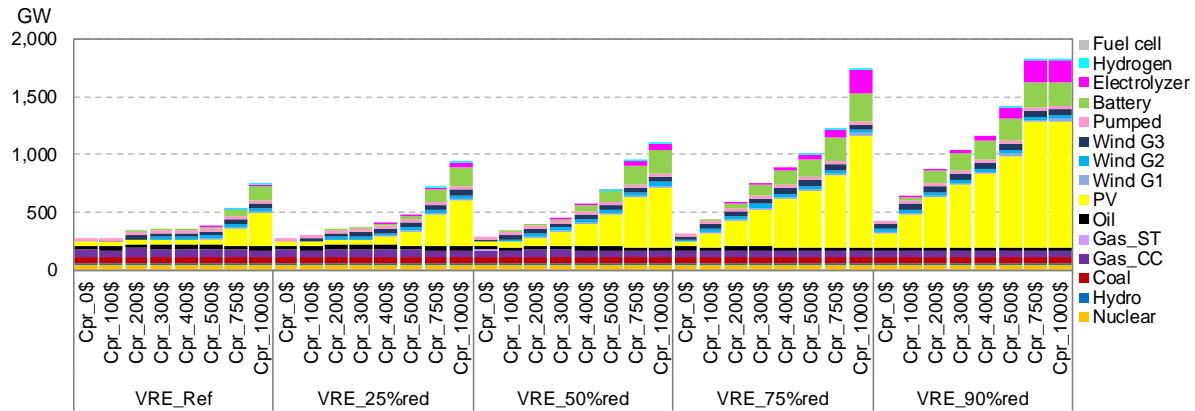

Fig. 3　　Installed power generation capacity of Japan

covering the final consumption. The total required installed capacity is estimated at 1729–1819 GW. This is five times the total installed capacity of 2016 (approx. 325 GW). There are high expectations that renewable hydrogen and methane synthesis would lead to sector integration and decarbonization, but the study shows that achieving decarbonization through these methods would require developing large amounts of renewable energies. Note that land-use restrictions related to solar power were not considered in this assessment; however, it will need to be considered in the process of realizing these scenarios as introducing such large capacities could affect land usage.

To illustrate the supply and demand for electricity when methane synthesis is introduced, the situation in Tokyo during the first week of April with VRE_90%red and Cpr_1000$ is shown in Fig. 4a. The solution with the optimal cost was to have a solar PV capacity far exceeding the final consumption and to ensure the supply-demand balance through day-time charging and discharging of batteries, while using day-time electricity for water electrolysis. Figure 4b shows the amount of stored hydrogen. Hydrogen is produced primarily in the daytime, but the figure shows that the hydrogen is being stored on a daily to weekly cycle to level the hourly output. Storage may play an important role in ensuring the supply-demand balance of hydrogen.
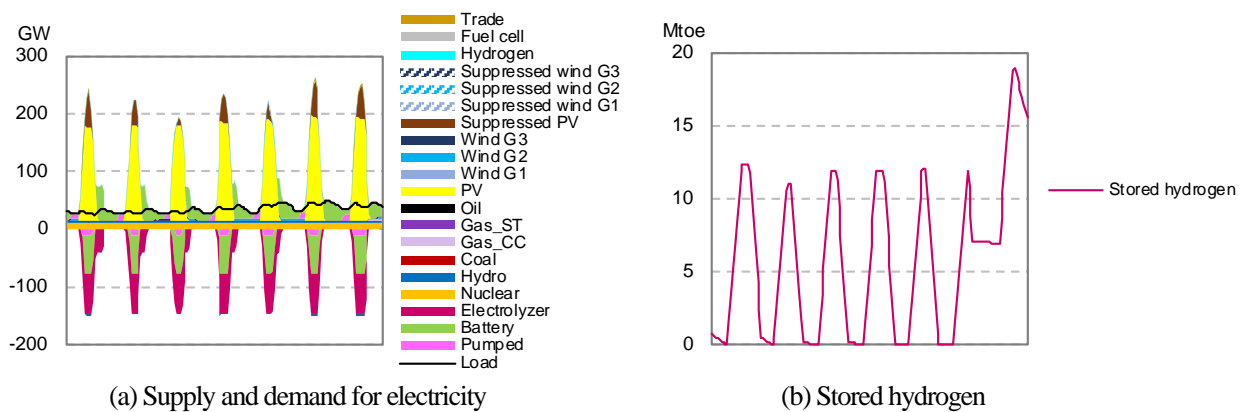

(a) Supply and demand for electricity

(b) Stored hydrogen

Fig. 4　　Supply-demand balance in the Tokyo region (first week of April)

3-3. CO_2 emissions

Figure 5 shows CO_2 emissions. The solid bars represent the net emissions from the electricity and city gas sectors (the double red-lined box in Fig. 1: the carbon contained in the fuel for coal- and oil-fired thermal power plants and imported LNG) while the shaded bars indicate the amount of CO_2 from burning synthetic methane. As the carbon from synthetic methane comes from the CO_2 captured in the industrial sector, synthetic methane is deemed to have effectively net-zero emission.

The net emissions from the electricity and city gas sectors tend to decrease as the carbon tax rate goes up. However, for
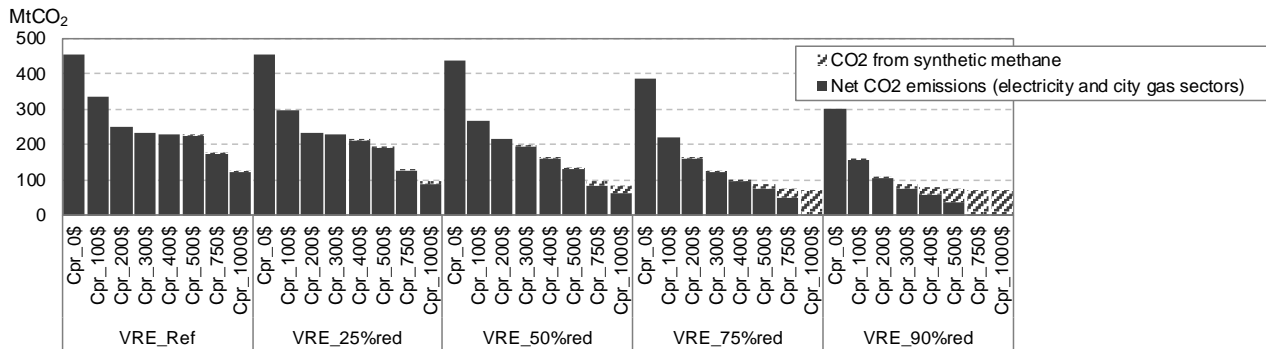
Fig. 5　CO_2 **emissions from the electricity and city gas sectors**

VRE_Ref, VRE_25%red, and VRE_50%red, imported LNG is selected even under a tax rate of US$1000 per tCO_2, resulting in net emissions of 62–121 $MtCO_2$. Meanwhile, net emissions were suppressed significantly under high tax rates for VRE_75%red and VRE_90%red through the use of synthetic methane. For instance, in a case with VRE_90%red and Cpr_1000$, net emissions decreased to 2 $MtCO_2$. As a result of avoiding 68 $MtCO_2$ of emissions (the shaded areas in the figure) in effect through carbon recycling, electricity and city gas supplies had near-zero emissions. This is regarded as the effect of using synthetic methane. Note that we deemed synthetic methane as being carbon-neutral and attributed the CO_2 reduction effect to the electricity and city gas sectors in this study. However, when implementing carbon recycling in society, whether the source or the user should get credit for the recycled CO_2, or whether it should be allocated to both parties, may become a major subject of discussion. In-depth discussions will also be needed on the institutional aspects going forward.

4. Conclusion

　This study presented a techno-economic assessment on synthetic methane in Japan employing a multiregional, high time-resolution, and optimized electricity and city gas supply model for Japan. Sensitivity analysis of VRE cost, which is the dominant factor for the methane production cost, and of carbon tax rates implies that cost reduction of renewables combined with a high carbon price, such as a 75% VRE cost reduction, would be crucial to accelerate synthetic methane. Developing technologies for reducing renewable energy costs and strengthening environmental policies are regarded as the key for the widespread use of synthetic methane. Another interesting result is that decarbonizing electricity and city gas with VRE, hydrogen production, and synthetic methane would considerably boost the VRE capacity as new plants become necessary for producing hydrogen as well as to meet final consumption.

　Future challenges for this study include refining the assumptions, and modelling and analyzing innovative technologies. Specifically, this includes studies taking into account the feasibility of CO_2 capture in each business in the industrial sector, and the feasibility assessment of methane synthesis using new technologies including co-electrolysis.
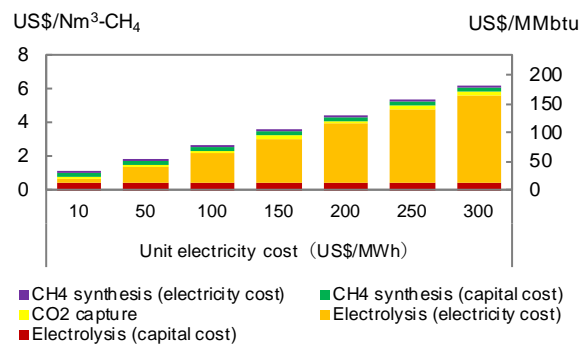
Appended fig. 1　Cost structure of synthetic methane production

Appendix　　Cost structure of synthetic methane production

Appended fig. 1 shows the cost of producing synthetic methane calculated based on the water electrolysis system, CO_2 capture (power generation and industrial sectors) and the cost assumption for methane synthesis described in Section 2.2. The utilization factor of the water electrolysis and methane synthesis systems were set at 30%, and the transportation cost for CO_2 and hydrogen were not considered (it was assumed that water electrolysis, CO_2 capture, and methane synthesis were all conducted in neighboring locations). A sensitivity analysis based on various unit electricity prices showed that the cost of electricity for water electrolysis becomes the dominant factor for a unit electricity price of US$50/MWh or higher. One of the main reasons is that as much as 4 Nm_3 of hydrogen is required to synthesize 1 Nm_3 of methane. Further, compared to Japan's LNG import price (US$9.4/MMBtu in FY2017, US$1 = 100 yen), the cost of synthetic methane would be 3.1 times as high even when the import price is US$10/MWh, indicating that cost is a problem.

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Study on FIP Policy Design by Using Multi-agent Based Electric Power Market Simulation Model

Sichao Kan [*]
Yoshiaki Shibata [**]

A multi-agent based electricity market simulation model is used to study the possible effects of variable renewable technologies on the electricity market and the implications for the design of the feed-in premium (FIP) policy, which is being discussed by government committees in the context of revision of the current feed-in tariff mechanism in Japan. The paper focuses on the impact of solar PV in Kyushu. The results suggest that under a FIP price of 10 yen/kWh, the breakeven cost of solar PV (in Kyushu) is under 150,000 yen/kW. However, if the amount of solar PV increases from 7,850 MW to 16,673 MW, the monthly average market value of solar PV would decrease by 3–4 yen/kWh and cheaper solar PV cost would be required to achieve breakeven. Although batteries can help to increase solar PV' revenue from electricity market, to make the investment on batteries economically make sense, the cost of batteries need to be below 15,000/kWh.

Key words: FIP, renewable energy, electric power market simulation

1.   Background and purpose

The Japanese government is currently considering revising the feed-in-tariff system for renewable energies (renewables), and has indicated a policy of migrating solar PV and wind power to the feed-in premium (FIP) system[1].

The FIP system is expected to promote the integration of renewables into the electricity market. However, the problem is that an influx of solar PV and wind power (variable renewable energy (VRE) power sources) that have a low marginal cost could drive down the market price of wholesale electricity market, and thus the negative impact on the revenue of VRE itself (Referred to as "cannibalism")[2,3].

By a case study of Kyushu, which leads Japan in terms of installed solar PV capacity, this study focuses on the following topics: possible impact on market price when there is an influx of solar PV into the wholesale electricity market (cannibalism), the effect of installing batteries on easing the cannibalism phenomenon, economic efficiency of solar PV and batteries under the FIP system, and implications for a better design of the FIP system and for solar PV to become independent from subsidies in the future.

2.   Methodology and key assumptions

2-1. Assumptions for the FIP system mechanism

Under the FIP system, the revenues for renewable power sources consist of two parts: revenue from selling electricity in the wholesale market, and the premium (subsidies) that is added onto the market prices. The FIP design can be classified into the variable-premium type and fixed-premium type depending on how the premium is determined (Fig. 1). Japan is considering a hybrid FIP design between the two in which the reference price changes at a given interval, a system similar to the German FIP system. The analysis of this study is carried out based on this type of FIP design (details elaborate later).

A premium is the difference between the FIP price (purchasing price paid to the VRE developer) and the reference price. The FIP price for solar PV is assumed to be 10 yen/kWh, which is in line with the lowest successful bidding price at the fourth auction for solar PV (10.5 yen/kWh[4]).
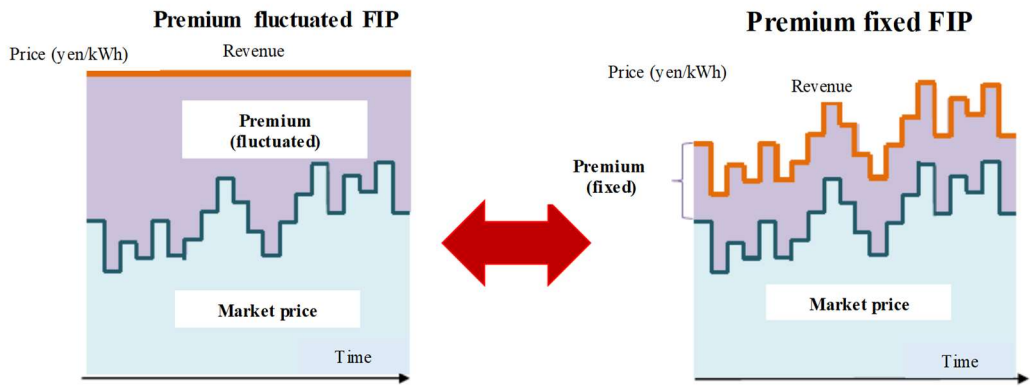
Fig. 1　Illustration of two different FIP types

Source: Material for the first meeting of the Subcommittee on System Reform for Renewable Energy as a Main Power Source[1]

In the German FIP system, the method of calculating the reference price depends on the power source. According to the German FIP design the reference price for renewable technologies is assumed as follows: the reference price for a renewable power source with stable output (biomass, geothermal, and hydropower) is set to the average wholesale electricity market price[5]. Meanwhile, the reference price for VRE is technology specific average market price, which is calculated based on the market price at the time of successful VRE sale and the VRE generation, given by:

$$\text{Reference price } (VRE_i) = \frac{\sum_{t=1}^{n}(market\ price\ of\ hour\ \text{t} * VRE_i's\ market\ settled\ amount\ of\ hour\ \text{t})}{monthly\ generation\ of\ VRE_i}$$

(1)

where, n is the number of hours in a month and i is the type of VRE technology. In this study, the reference price is set to the monthly technology specific average wholesale electricity market price, and the premium of the relevant month (which is the difference between the FIP price and the month's reference price) is calculated after the month's trading.

2-2. Electricity market simulation model

The analysis in this study needs to have market price changes under various circumstances as inputs for assessing the impact of large amount of solar PV on the market price, and the economic efficiency of solar PV and the installation of batteries under a market price-linked FIP system. As the historical market price data of Japan Electric Power eXchange (JEPX) alone is not sufficient for this purpose, we built a multi-agent-based model to simulate the electricity market.

Both the sellers and the buyers are treated as an agent. A market bidding block is generated for each agent (both the buyer and the sellers) using a program, and the market settling price and the trade volume are calculated based on a market trading mechanism (Fig. 2) similar to that of JEPX.

JEPX has a day-ahead (spot) market and real time market.　This study assumes that VRE sources participate only in the day-ahead market. In the JEPX the day-ahead market is traded at a 30-minute interval, however, because only hourly power generation output data is available 1-hour interval market trade is calculated in the simulation model.

The precondition for the simulation is that the entire electricity demand and supply in Kyushu Electric's service area is traded in the electricity market, and the agent assumption is that one agent as the buyer and multiple agents for each power generation technology. The bidding block for the buyer agent is generated using the demand function shown in Fig. 3. Here, β is set to -0.05 and the bidding price cap to 85 yen/kWh. Q_0 is the actual hourly electricity demand (2017) disclosed by Kyushu Electric[7]. For the buyer's bidding block, the bidding amount is 3MW and the bidding price (p) is calculated by the demand function with the input as the demand that decreases in units of 3 MW (q) down to Q_0. The base price (P_0) is set to 5 yen/kWh.
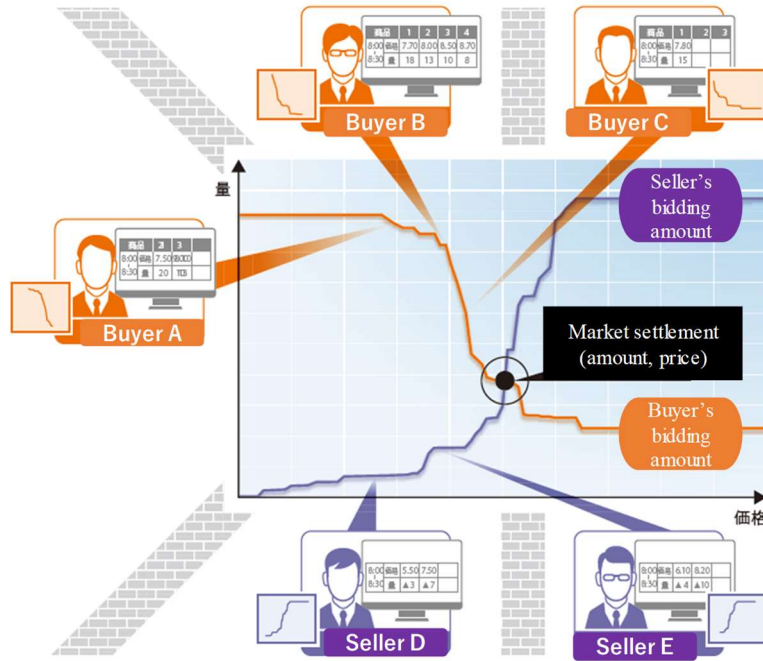
Fig. 2   Image of market trading and market settlement
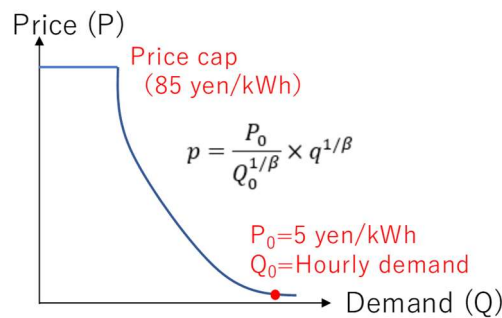
Source: JEPX[6]

Fig. 3   Relationship between electricity demand and market bid price

The market bidding price for the seller agents is assumed to be the sum of marginal generation cost of each technology and the profit (α). The value of α is selected from among the 21 options predefined using an enhanced learning method called Q-learning based on the objective to maximize the agent's revenue from market trading. The range of α is from 0 to 80. Marginal cost for each power generation technology is set based on the calculation results from Power Generation Cost Verification Working Group[10] (Table 1). Fuel costs are considered to be constant over the simulation period. As this study assumes that the seller's minimum bidding price equals to its marginal cost, the market price does not become 0.

The bidding amount of each seller agent is set based on the installed capacity for non-VRE technologies For VRE technologies, the capacity that can be offered at a certain hour is calculated based on the installed capacity and the output curve (which is estimated from the historical output data). The installed capacity is from the data disclosed by Kyushu Electric Power Company (Table 1).

For simplification, we assume no inter-region electricity trading between Kyushu and other areas and balancing by pumped hydro power is not considered either.

Table 1   Marginal cost and current installed capacity for each power generation technology

	Hydro	Nuclear	Coal	Gas	Oil	Biomass	Geothermal	Solar PV	Wind	PV + battery
Marginal cost （yen/kWh）	2.3	5.4	7.2	11.4	26.7	25.2	12.5	3.34	4.15	3.34
Capacity （MW）	1,901	1,780	3,983	4,981	3,560	52	192	7,850	500	Scenario

Source: Power Generation Cost Verification Working Group[10], Kyushu Electric Power Company[7],[11]

2-3. Setting the simulation cases

An increase in solar PV that has a low marginal cost is expected to lower the day-time market prices and drive down the revenue from electricity market of solar PV itself. Solar PV developers are able to increase their market sales revenues by installing batteries and selling the power when the market price is high, but this would require additional investment for battery installation. Whether there will be sufficient incentive for developers to install batteries depends on whether the increase in market sales revenue is enough to at least cover the additional battery investment. Under the FIP mechanism, installing batteries could also cause the change of the reference price because of the shift of the overall output pattern of solar PV. As a result, the premium paid to all the developers will also change, which will affect the revenue of the developers without batter installation.

Simulation cases in this study are shown in Figure 4. Focuses of the analysis include: impact of solar PV on the electricity market, price benefit of revenue increase by installing batteries, the economic viability of solar PV and batteries under the FIP mechanism, implications for better FIP design and future subsidy phase-out conditions.
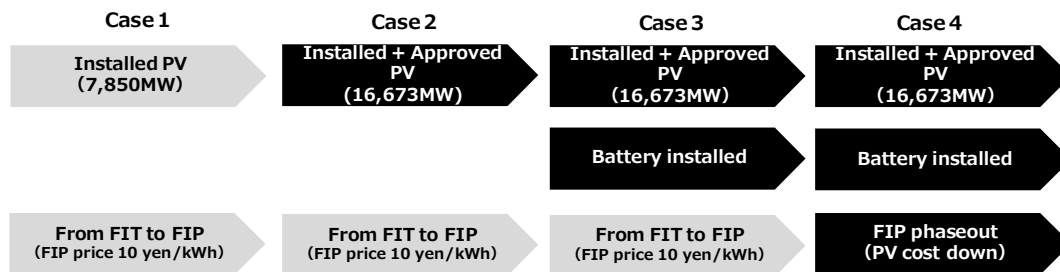

Fig. 4   Simulation cases

2-4. Output pattern: solar PV + batteries

The power output pattern of the combined solar PV and battery system is given as an exogenous variable. Five cases of battery/solar PV capacity from 1 kWh battery /kW solar PV to 5 kWh battery/kW solar PV are considered. Although there can be various operation patterns of batteries, for simplification reason this study assumes an pattern under which generation from solar PV is stored to the battery to its maximum capacity during day-time and the stored electricity is sold to the market in the evening hours (17:00–21:00) when price is high(Fig. 5).

As the amount of solar PV output that can be shifted to the evening varies depending on how much battery capacity is installed, the cost-effectiveness of batteries will vary depending on their installed capacity.
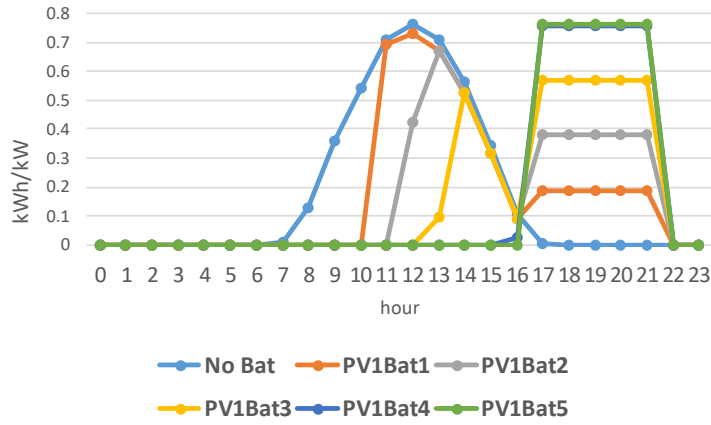
Fig. 5   Image of solar PV + battery output

3.   Results

3-1. FIP mechanism and the impact of influx of solar PV

As mentioned before, the influx of solar PV could result to market price falling down during day-time and in turn the reference price of solar PV (the monthly average market price of solar PV). For example, if the amount of solar PV traded at the electricity market were to increase from the current level (7,850 MW as of 2017) to the current approved FIT capacity (16,673 MW[1]), the reference price for solar PV would fall by 3–4 yen/kWh (Fig. 6).

As a result of the market price fall during day-time hours, the annual revenue from electricity sales in the market is estimated to decrease by approx. 5,000 yen per kW for solar PV developers (Fig. 7). To compensate possible revenue reduction from the market and make the new installed solar PV project economically viable more subsidies or faster system cost down are required.
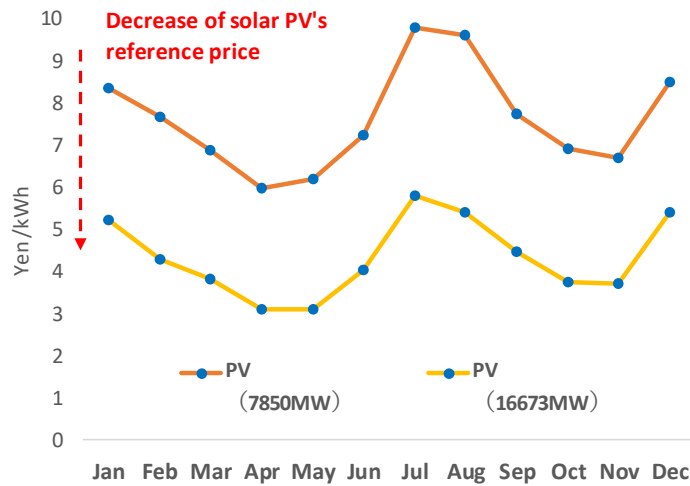

Fig. 6   Change in the reference price of solar PV as the solar capacity increases in the market
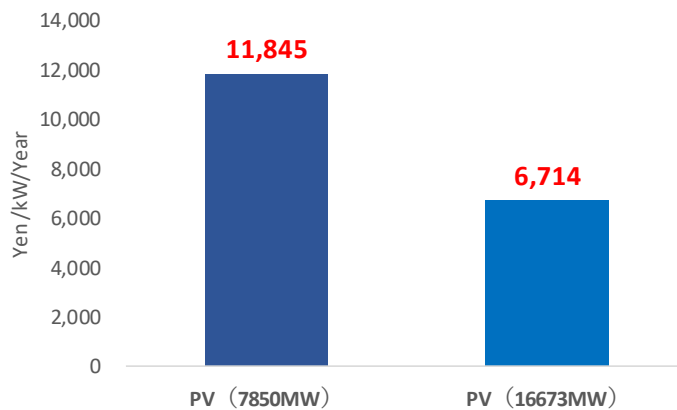
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[1] As of May 2019.

Fig. 7   Change in revenue from sales in the market as solar PV increases

3-2. Effect of installing batteries to boost revenue

One way to improve solar PV's revenue from electricity market is to install batteries, which will enable selling the electricity at hours when the market price is high. The revenue-increasing effect of batteries is discussed based on the market simulation results from the case with 16,673 MW of solar PV (equal to the current licensed capacity) in the electricity market.
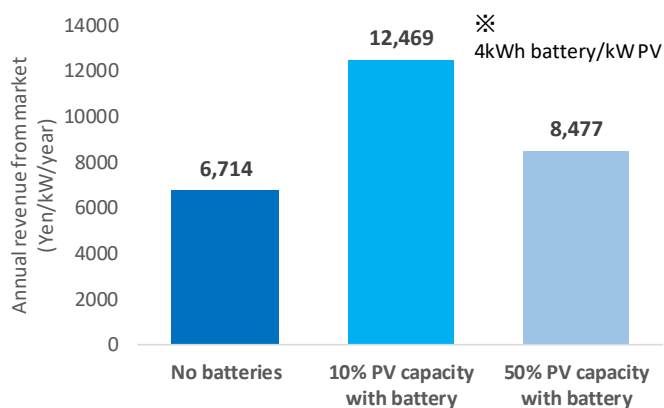

Fig. 8   Change in market sales revenue from installing batteries

The result in Fig. 8 shows that the annual market sales revenue is higher for solar PV with batteries than that without. In the case when batteries are installed to 10% of the solar PV capacity (4 kWh of battery capacity for 1 kW of solar PV), the annual revenue per kW (of solar PV) becomes 5,700 yen higher than that with no batteries (Fig. 8). However, if the capacity of solar PV with batteries becoming too much, more solar PV developers will choose to sell electricity during evening hours, that might drive down the market price in these hours, making the revenue of "solar PV + batteries" become lower (comparing to the case when the capacity of solar PV with batteries is smaller). Based on the simulation results it is found that if the percentage of solar PV capacity with batteries increases from 10% to 50% of the total, the revenue for "solar PV + batteries" system falls by approx. 4,000 yen/kW per year (Fig. 8).

3-3. Economic efficiency of solar PV and batteries

If FIP mechanism with a FIP price of 10 yen/kWh were applied to all the current solar PV capacity (7,850 MW as of 2017), the solar PV system cost need to be lower than 150,000 yen/kW to make the business viable. However, if the solar PV capacity increases to 16,673 MW (the approved solar PV capacity), because of the reduced market price and curtailment (the solar PV capacity exceeds the total demand), full-year revenue of solar PV will fall below the breakeven point (Fig. 9). While installing batteries is expected to increase market sales revenue, the cost effectiveness of batteries largely depends on

their cost. Under a FIP price of 10 yen/kWh and a solar PV system cost of 150,000/kW as in the case above, a battery cost of 90,000/kWh would worsen the deficit for the overall system (Fig. 9). A battery cost of 15,000/kWh or lower is required for the overall system cost to break even (in the case of 4 kWh of battery capacity for 1 kW of solar PV) (Fig. 9). Considering that the battery cost is around 40,000 yen/kWh ($380/kWh[12]) even in the United States where there is more experience for utility scale batteries a further reduction in battery cost is required to give solar PV developers an incentive to install batteries.

Figure 9 also shows that the cost effectiveness of batteries depends on the installed battery capacity.
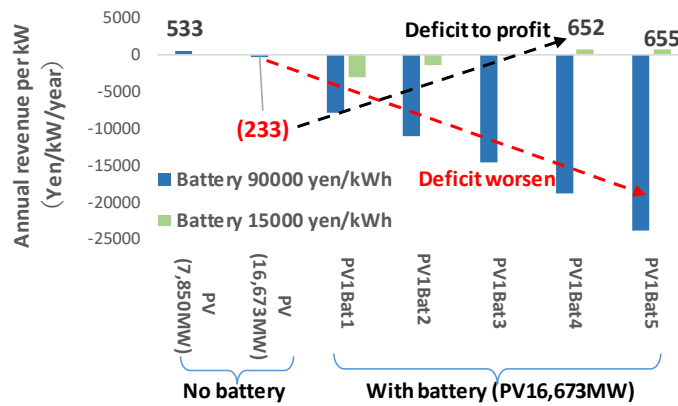

Fig. 9   Economic efficiency of solar PV and batteries under a FIP price of 10 yen/kWh and a solar PV cost of 150,000 yen/kW (batteries installed for 10% of the solar PV capacity)
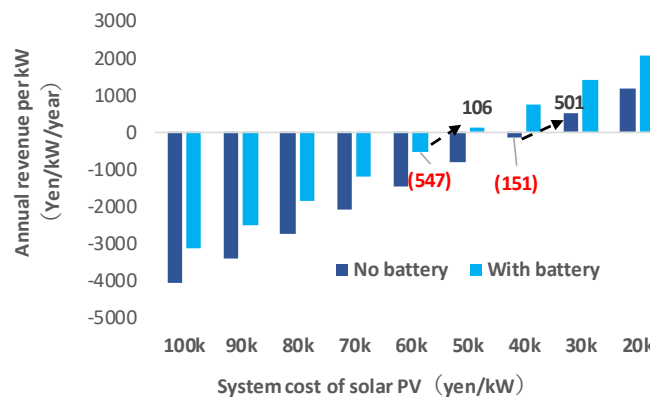
3-4. Gaining independence from subsidies

Fig. 10   Comparison of annual revenues of unsubsidized solar PV (with and without batteries) (yen/kW/year)

As the revenue of solar PV from electricity market would decrease if large amounts of solar PV were to enter the market, a drastic reduction in system cost would be required for solar PV to become independent from subsidies. For example, if there is 16,673 MW of solar PV in Kyushu's electricity market, the system cost for solar PV must be below 30,000–40,000 yen/kW to make the business viable without subsidies (Fig. 10). If the battery cost can be lowered to 20,000 yen/kWh or less for the same conditions, the requirement for solar PV's system cost reduction becomes less strict, thanks to the revenue-increasing effect of batteries discussed earlier (3 kWh of battery capacity for 1 kW of solar PV). Thus, a reduction of battery cost can contribute to making solar PV graduate from subsidies sooner.

4. Conclusion and implications

Integrating solar PV into the electricity market under the FIP system could cause the "cannibalism," significantly affecting

solar PV itself. The simulations in this study for Kyushu show that if the region's entire approved solar PV capacity (16,673 MW) were to enter the electricity market, the annual market sales revenue of solar PV will decrease by approx. 5,000 yen/kW. Installing batteries and shifting selling power during evening hours (when the market price is usually hither) would boost the revenue from electricity market, but the battery cost must be lowered significantly to ensure business viability. To encourage make solar PV more valuable to the electricity market, it is essential to accelerate efforts to drive down the battery cost. The study also found that if the battery cost falls to around 20,000/kWh, solar PV system with batteries may become independent from subsidies more quickly than that without batteries.

If the capacity of solar PV (with batteries) that are able to sell electricity in high market-price hours increases, the market prices for those hours will decline, which could in turn cause the of solar PV + battery systems' revenue from electricity market decrease. If renewable power generation is to be completely integrated into the market with batteries, dynamic battery operation responding to the change of market prices will be necessary to maximize the developer's revenue.

To address the issue of "cannibalism" that might occur when large amounts of VRE with low marginal costs enter the electricity market, a significant reduction of the cost of both the renewable technologies and batteries is required. At the same time, VRE developers can avoid the risk of revenue reduction from the electricity market due to "cannibalism" by securing alternative sales channels, such as corporate PPA (Power Purchasing Agreement).

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Oil and Gas Upstream Sector:
Changes of Major Players and the Market across the Ages ◆

Kazuo Kotani *

Introduction

According to Dr. Yuval Noah Harari's bestseller "Sapiens: A Brief History of Humankind," the modern humans known as Homo sapiens emerged 200,000 years ago after human ancestors appeared 2.0 million to 2.5 million years ago on the earth that was formed 4.5 billion years ago. Dr. Harari argues that Homo sapiens have developed through three important revolutions based on their unique capacity to believe in things existing purely in the imagination and their cognitive capacity for fiction.

- The first one, the Cognitive Revolution, kickstarted about 70,000 years ago through which Home sapiens came to form social groups with the capacity to share fictions such as languages and primitive religions.

- The second one, the Agricultural Revolution, began about 10,000 years ago when Homo sapiens began to devote themselves to agriculture, forming settled social groups through farming and later creating fictions like currencies, empires and religions (ideologies), as well as universal order.

- The third one, the Scientific Revolution, came some 500 years ago as the greatest engine to use science not only for researching but for making constant progress on social, political and economic systems such as national sovereignty states, democracy, and financial and investment mechanisms toward present maturity. In 500 years from 1500, global population has increased 14-fold, production 240-fold and energy consumption 115-fold.

The 500 years after the Scientific Revolution could be subdivided into two by the first industrial revolution in the second half of the 18th century, in which the United Kingdom took the lead with the emergence and improvement of steam engine technology, and the energy revolution of coal use as a power source which is considered to be the biggest historical turning point. Fossil fuels have replaced natural energies like firewood, human labor, animal power, hydropower and wind since then and have been regarded as the main energy source to develop human economies and social infrastructure, paving ways for enhancing living standards, affordability of population growth and seeding capitalist economies and democracy,

Coal was the first fossil fuel to be applied to replace natural energies at the initial stage of the industrial revolution. As industrialization has shifted from light industries to heavy industries, such transportation means as railway trains and steam ships and automobiles have developed utilizing fossil fuels. Almost a hundred years later, in the second half of the 19th century, the leading role of primary energy shifted to oil, which is easier and more convenient to handle than coal.

The rapid development of the heavy and chemical industry owning to technological innovations and the energy transition to oil between the late 19th century and the early 20th century could be called the second industrial revolution. The relatively smooth energy transition to oil is apparently attributable to two factors. First, oil and gas exploration grew more active in various areas of the world, leading to the discovery of good enough deposits sufficient to meet energy demand that was diversifying and rapidly expanding. Second, continued technological innovations at the oil production, transportation and sales stages allowed oil to sustain its cost competitiveness and economic rationality suitable for the best primary energy source.

The time span of about 270 years of coal utilization since the first industrial revolution or that of more than 160 years after the emergence of oil industry in the United States accounts for only a tiny portion of the 200,000 year-long history of Homo sapiens. However, in only one and a half centuries, various players have energetically tried to become dominant in

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their business and control the market by making full use of Homo sapiens' given capability to create, believe in and share fictions. This is because oil and natural gas, originating from the same source of hydrocarbon, are not only key primary energy sources important to humans' economic and social infrastructure but also a strategic commodity indispensable for national security. This paper reviews the chronical changes of major players and the market in some 160 years since the emergence of the oil and gas industry in the second half of the 19th century and explores future prospects in a manner to take lessons from the past.

1. Second half of 19th century

Table 1 shows major oil-producing countries' crude oil production trend between 1860 and 1930. Figure 1 represents a historical crude oil price trend from 1861 to 2018 presented in BP Statistical Review of World Energy 2019. In the second half of the 19th century, when the oil business began as an emerging industry, history was looked back on, mainly in the United States and Russia, which led the industry.

Table 1. Major oil-producing countries' production trend (1860-1930)

| Units: 1,000 barrels/% per year	U.S.		Mexico		Russia/USSR		Dutch East Indies (Indonesia)		Global total
	Production	Share	Production	Share	Production	Share	Production	Share	Production
1860	500	98	-	-	-	-	-	-	509
1870	5,261	91	-	-	204	4	-	-	5,799
1880	26,286	88	-	-	3,001	10	-	-	30,018
1885	21,859	59	-	-	13,925	38	-	-	36,765
1890	45,824	60	-	-	28,691	37	-	-	76,633
1895	52,892	51	-	-	46,140	44	1,216	1	103,692
1900	63,621	43	-	-	75,780	51	2,253	2	149,137
1905	134,717	63	251	0	54,960	26	7,850	4	215,091
1910	209,557	64	3,634	1	70,337	21	11,031	3	327,763
1915	281,104	65	32,911	8	68,548	16	11,920	3	432,033
1920	442,929	64	157,069	23	25,430	4	17,529	3	688,884
1925	763,743	71	115,515	11	52,448	5	21,422	2	1,068,933
1930	898,011	64	39,530	3	125,555	9	41,729	3	1,410,037

Source: World Oil
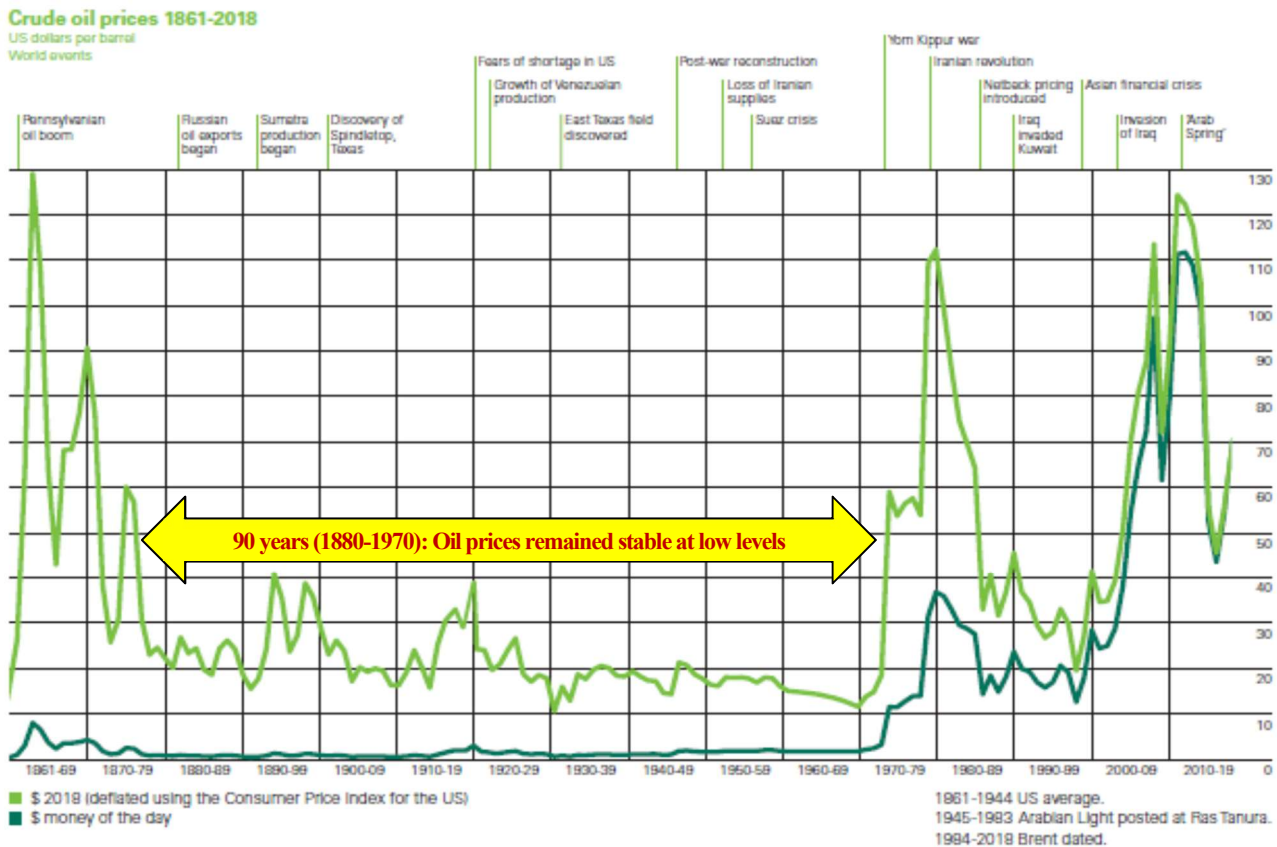
Fig.1   Crude oil Prices 1861-2018

Source: BP Statistical Review of World Energy 2019

1-1. U.S.

In the 1850s, late in the Edo period, when the Tokugawa Shogunate was running about in confusion due to Commodore Matthew Perry's arrival, lamps using whale oil began to be used in Japan. At that time in the U.S., the oil industry was born because black oil used as a drug by Native Americans, once refined and processed, was found more suitable for lighting application for lamps. In August 1859, Edwin Drake successfully drilled the first mechanized oil well in the Oil Creek valley near Titusville in Pennsylvania, triggering an unpreceded oil investment boom as new entrants rushed into the oil field development one after another throughout the country. Oil prices reportedly plunged from a peak of $20 per barrel to $0.1/bbl in 1861 because of oversupply from new production while demand at that time was only limited to lamp and lubricant oil.

John D. Rockefeller, who started an oil refining business in Cleveland, Ohio in 1863, founded Standard Oil Company of Ohio (SOHIO) in 1870, using an oligopoly and trusted financial methods of oil refining by taking control of transportation measures such as railways, as the U.S. oil industry entered a realignment and survival period due to oversupply. In less than a decade, he built a monopoly on the oil refining sector and markets in Pennsylvania, as well as Texas and California, across the United States. Firstly, Rockefeller employed a price-cutting offensive and excluded or acquired competitors to become the largest oil refiner in Cleveland that accounted for a quarter of total U.S. oil refining capacity. He then expanded his corporate acquisitions into East Coast oil refining centers New York and Pennsylvania and took control of sales companies in the southern state of Texas to further expand his business. Rockefeller also acquired transportation means energetically, taking control of most U.S. railway tankers and three-quarters of trunk pipelines by 1876. By 1880, he came to capture 90-95% of U.S. petroleum products sales. In 1882, Rockefeller formed Standard Oil Trust to control his expanded, diversified conglomerate. Standard Oil Trust controlled about 40 companies including 14 wholly owned subsidiaries such as Standard Oil of New Jersey（the predecessor of Exxon）, Standard Oil of New York（which later merged with Vacuum Oil, another firm under the Standard Oil Trust umbrella, into the predecessor of Mobil） and Standard Oil of California（the predecessor

of Chevron）. Standard Oil Trust then launched international expansion, entering European and South American markets.

1-2. Russia

Major oil producers in the second half of the 19th century were the United States, Romania and Russia's Caucasian region. Russian crude oil production, totaled only 0.2 million barrels in 1870, rapidly expanded from the mid-1870s and reached 29 million barrels in 1890 (Table 1). Russian lamp oil appeared in the European market for the first time in 1883 and fast spread there, competing with U.S. lamp oil in 17 countries in 1887. Behind the fast spread were Sweden's Robert & Ludwig Nobel (who later created the Nobel Prize) and France's Rothschilds family.

The Nobel brothers built a refinery in the Russian oil-rich region of Baku in 1875 and founded the Nobel Brothers Petroleum Production Co. to launch oil production. In 1888, the company accounted for one-third of Russian lamp oil production. The Rothschilds acquired an oil concession in Baku in exchange for loans to the Batum railway before founding Caspian and Black Sea Petroleum (nicknamed Bnito from its Russian-language name). Bnito signed up with many small oil refiners to become the largest exporter of Russian lamp oil and develop sales networks in Europe. In the second half of the 1880s, it expanded into the oriental market.

In a bid to export Russian lamp oil to the oriental market, British trader Marcus Samuel in 1891 signed a 10-year exclusive distributorship agreement for Russian lamp oil with the Rothschilds who controlled Bnito. In 1897, the British trader founded Shell Transport and Trading Company to expand oil business.

The remarkable Russian oil industry development boosted Russian lamp oil's global market share from 3% in 1884 to 22% in 1889, while the share for U.S. lamp oil fell from 97% to 78%. Russian lamp oil thus became an unignorable rival for U.S. lamp oil.

1-3. Asia

The Netherlands' Royal Dutch Petroleum, founded in 1890, built a refinery in Pangkalan Brandan to refine crude oil produced on the east coast of Sumatra as part of the Dutch East Indies (now Indonesia), launching lamp oil exports in 1892. Its export business to Asia and Oceania (Singapore, the Malay Peninsula, Japan, China, the East Indies and Australia) became competitive to the rival U.S. exporter in several years. Since then, the three-way market battle between Royal Dutch Petroleum, Standard Oil of the U.S. and Shell of the United Kingdom has intensified.

Shell was negotiating a partnership with both Standard Oil and Royal Dutch in parallel, but in December 1901, it suspended talks with Standard Oil, agreed in principle to partner with Royal Dutch, and signed the so-called British-Dutch Agreement. This agreement was not enough to stop their sales competition in the Asian market. In June 1903, however, the Rothschilds that provided Russian kerosene (lamp oil) into the Asian market joined the British-Dutch group to create a new joint venture, Asiatic Petroleum Co., of which stakes the three equally owned. In 1907, Royal Dutch and Shell merged into Royal Dutch Shell Group (hereinafter referred to as Shell). The terms of the merger gave 60% ownership of the new group to the Dutch arm and 40% to the British. Asiatic was integrated into the new group.

2.　First half of 20th century

The oil industry at the beginning of the 20th century was dominated by Standard Oil Group who dominantly controlled U.S. oil resources and Shell Group based on oil resources in Southeast Asia.

2-1. Anti-trust law and Standard Oil breakup

In the United States in the early 20th century, new demand for oil emerged; one such demand was for gasoline as Ford Motor invented and developed a gasoline-based Model T Engine and started selling Model T cars in 1908, and another was for heating oil for stove fuel. Driven by the surge in oil demand, Standard Oil grew more and more. In the second half of the 19th century in the United States, monopolies formed under the free competition policies; however, the presence of big monopolies came to bar newcomers and led to a number of situations in which free competition was hindered. In response, the U.S. Congress recognized the need for regulating monopolies and passed the Sherman Act as the first U.S. anti-trust law

in 1890. (Furthermore, the Clayton Act and the Federal Trade Commission Act were enacted in 1914 to enhance the Sherman Act. The three acts are collectively called Anti-Trust Law.)

As of 1904, Standard Oil controlled 91% of U.S. domestic crude oil production and 85% of retail oil products sales and exported 55% of oil products (mostly lamp oil) to various parts of the world. In 1909, the Justice Department sued Standard Oil for violating the Sherman Act. On May 15, 1911, a Federal Court ruled to break Standard Oil up into 34 regional companies.

2-2. Dominance of Seven Majors (Seven Sisters)

In the 1910s, spinoffs from the Standard Oil breakup began to compete with each other and focused on expanding sales in foreign countries where military oil demand increased due to World War I. During the war between 1914 and 1918, aircraft, tanks and fuel oil-powered ships flourished, leading the world to recognize oil as a strategically important good. After the Ottoman Empire was defeated in the war and broke up, the United Kingdom approached the newly born Turkey as well as Iraq that had been under Ottoman control, triggering an oil exploration boom in the Middle East. The winners in the Middle Eastern oil-drilling concessions were Standard Oil spinoffs, as well as British and Dutch companies that had successfully drilled oil in their colonies. Among the spinoffs of the Standard Oil Group holding company, three entities later grew into international oil majors, including Standard Oil Company of California (Socal, the predecessor of Chevron), Standard Oil Company of New York (the predecessor of Mobil and ExxonMobil) and Standard Oil Company of New Jersey (the predecessor of Exxon and ExxonMobil).

In 1908, the Briton William Knox D'Arcy discovered the first oilfield in Persia (now Iran). Based on the oilfield, Anglo-Persian Oil Company (the prototype of BP) was founded in 1909. In the United States, oilfields were discovered one after another in Texas and California, leading to the founding of Texas Fuel Company (renamed Texas Oil Company in 1903, the predecessor of Texaco) in 1901 and that of Gulf Oil Corporation in 1907.

In this way, five U.S. international oil majors – Exxon, Mobil and Socal that originated from Standard Oil, and Texaco and Gulf that grew through an oil boom in the southern and western U.S. – and two European international oil majors – Royal Dutch Shell and Anglo-Persian (BP) – came to dominated the world's oil industry in the beginning of the 20th century, ushering in the age of Seven Sisters (Figure 2).

Esso	Mobil	Chevron	GULF	TEXACO	Shell	BP
Standard Oil of New Jersey (Esso)	Standard Oil Co. of New York (Socony)	Standard Oil of California (Socal)	Gulf Oil	Texaco	Royal Dutch Shell (Anglo-Dutch)	Anglo-Persian Company (APOC)

Fig.2   Logos of seven international oil majors (Seven Sisters)

From 1900 to 1950, oil production in oil-producing countries other than the United States and the former Soviet Union was mainly based on comprehensive concession contracts awarded to the Seven Sisters and other European and U.S. large oil companies. Oil companies granted extensive concessions had exclusive or monopolistic rights to do oil business in the host countries over a long term (usually more than 50 years). Although these oil companies were required, under the contract, to pay tiny royalties to them, the governments of oil-producing countries had no room to intervene in their business operations. The Seven Sisters cartel devised various pricing mechanisms to protect their rights such as the Gulf-plus pricing system and Middle East plus system in order to maintain centralized control over oil prices in the world.

The Seven Sisters took advantage of every means to secure their oil exploration and development concessions and maintain or expand their market shares. They also tried to create de facto standards to prevent their status from being threatened. In a representative case, Standard Oil NJ, Shell and Anglo-Persian signed the Achnacarry Agreement to fix their respective oil sales shares in former Ottoman Empire territories outside the United States at the 1928 levels. Anglo-Persian,

Shell and Standard Oil NJ/NY also signed the Redline Agreement under British, U.S. and French government approval to prohibit independent oil development in former Ottoman Turkish Empire territories and require participants in Turkish Petroleum Co. (renamed Iraq Petroleum Co. in 1929) to share oil concessions and operations.

The age of Seven Sisters lasted until the 1970s. As of 1949 after World War II, the Seven Sisters were said to be owned concessions accounting for 65% of global oil production and 43% of global oil deposits, dominating the oil global industry.

2-3. Sign of resource nationalism –

Given that global crude oil supply sources concentrated in the Middle East after World War II and that major oil consumers such as Europe and Japan began to refine crude oil on their own, international oil majors enhanced joint venture and other arrangements to jointly control large-scale oil resources in the Middle East and other oil-producing regions.

Saudi Arabian oil resources were initially put under control by Arabian American Oil Company（Aramco）, a joint venture between Socal and Texaco, before Standard Oil NJ and Standard Oil NY invested in Aramco in 1947. In this way, four U.S. international oil majors came to control Saudi oil resources. Iranian oil resources were owned by the Iranian Consortium including European and U.S. international oil majors from 1954 following a conflict over the nationalization of Anglo-Iranian Oil in 1951, as will be described later.

In Mexico (see Table 1) where some U.S. and European oil companies including Shell engaged in commercial oil production from around 1901, a constitution was established in 1917 to materialize the cause of the Mexican Revolution, providing for a land reform, workers' rights and national sovereignty over underground resources. Under the constitution, the then Cardenas administration in 1938 implemented the nationalization of oil resources and ousted foreign oil companies, first in the world. (In 2014, the Mexican oil sector was opened to foreign companies for the first time in 76 years.)

Venezuela, then more advanced than other oil-producing countries, became the first country to introduce an income tax system for oil companies' payments to an oil-producing country government. The country enacted the income tax system for the oil industry from 1943 and established a value added tax in 1948 to implement a profit-sharing scheme to ensure that 50% of oil business profit would become government revenue. Saudi Arabia, dissatisfied with oil companies' low royalty payments to the government, adopted a new concession sharing mechanism in 1950 to almost quadruple its oil revenue. Iraq and Kuwait followed this in a similar manner.

The introduction of income tax and other systems required changes on these countries' domestic laws (for income tax payments). As oil export prices per barrel (on a realized price basis) were required to be posted for calculating income subject to taxation, the posted price system of crude oil was introduced.

In 1951 when the income tax system was being generalized, Iran's Muhammad Mossadegh regime nationalized Anglo-Iranian Oil that had monopolized its oil industry. Sazo Idemitsu of Idemitsu Kosan Co. who was the model for a novel titled "Kaizoku to yobareta Otoko (A Man called Pirate)," cause a stir and successfully imported Iranian crude oil from the Mossadegh regime in 1953 using their own tanker "NISSHO MARU," which was quite a frightening event for European and U.S. international oil majors claiming their exclusive rights to Iranian oil. The nationalization eventually ended up as a failure in the face of direct and indirect resistance from international oil majors and their countries. In 1954 after Mossadegh's ouster, the nationalization impasse ended as Iranian Consortium, which was owned 40% by five U.S. international oil majors and 60% by British Petroleum (BP), Shell, France's CFP and the United States' Irikon, signed a contract work agreement with Iran.

3. Second half of 20th century

In the second half of the 20th century, the upstream oil and gas sector evolved into a global business targeting not only onshore underground but offshore waters in various areas of the world, in response to the dramatic growth of energy demand derived from the rapid increase of global population and industrial evolutions. Since 1950, every 10 to 15 years, cyclical upturns and downturns of the oil industry could be recognized that would bring major structural changes in the oil market and transitions in key players.

3-1. 1950s and 1960s: Postwar structural market changes – Middle East replacing U.S. as world's largest oil supplier

The United States, the world's largest oil exporter before the end of World War II, turned to be a net importer of crude oil and petroleum products from 1948 (Figure 3). On the other hand, the Middle East, of which crude oil production was still less than Venezuela accounting for 12% of the global production in 1948, came to account for around 20% at around 1953 and increased its importance as a crude oil supplier. The Middle East's share of oil imports into Western Europe, a major oil consumer, exceeded 50% soon after the war and rapidly expanded to more than 80% by 1958.
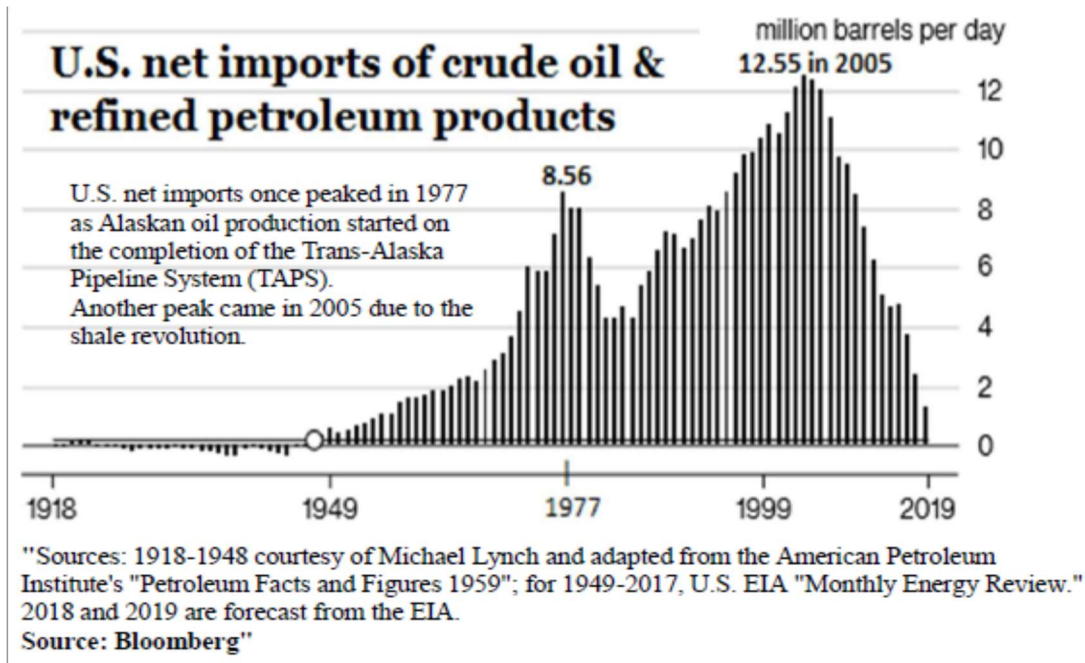

Fig.3   U.S. oil supply-demand balance

3-2. 1960s and 1970s: OPEC's rise and market dominance – End of low and stable oil prices

The Seven Sisters lowered the posted price, which is the basis for calculating income taxes paid to oil-producing countries, in both 1959 and 1960, reflecting a general downward trend of realized prices in the market. Oil-producing countries felt a sense of crisis about the risk of oil revenue drops through the posted price cut and recognized the need for defensive measures against the risk.

In September 1960, oil exporters Iraq, Iran, Kuwait, Saudi Arabia and Venezuela held a meeting in the Iraqi capital of Baghdad and agreed to create the Organization of the Petroleum Exporting Countries (OPEC), which was joined later by other oil-producing countries like Qatar, Indonesia, Libya, the United Arab Emirates, Algeria and Nigeria. Through a permanent agency aimed at regular consultations among the participating members, the OPEC oil-producing countries, who have covered most of government revenue solely dependent on payments from international oil majors to which they granted oil concessions, gradually implemented measures to take back oil pricing rights and concessions from the Seven Sisters and other foreign firms.

In the 1960s, energy demand continued to increase thanks to robust growth of the global economy, while surplus production capacity increased due to the development of new large oil fields, and crude oil prices continued to fall lower due to oversupply. While posted prices for the Middle East crude oils were held at 1960 levels due to OPEC resistance, dissatisfaction among OPEC countries was growing. In May 1970, the Libyan revolutionary government, an emerging oil-producing country that defeated the monarchy in a bloodless coup by Capt. Gaddafi and others, launched a hard line on raising oil prices (the posted price plus $0.3-0.4/bbl premium), triggering an OPEC price offensive.

OPEC countries succeeded in signing the Tehran agreement with international oil majors in February 1971, the Tripoli agreement in April 1971, the Geneva agreement in January 1972 and the new Geneva agreement in June 1973, winning

posted oil price hikes, income tax rate hikes and adjustments to the dollar's depreciation. Following the further price-raising offensive sparked by the fourth Middle East war of 1973 and the first oil crisis, the Seven Sisters completely lost their oil pricing rights to OPEC countries, ending the period of low and stable oil prices that lasted for about a century from the mid-1870s.

After the fourth Middle East War broke out on October 6, 1973, six Persian Gulf countries among the OPEC oil-producing countries announced to raise their posted crude oil price by 70% from $3.01/bbl to $5.12/bbl on October 16. On October 17, the Organization of Arab Petroleum Exporting Countries (OAPEC) decided to phase down crude oil production. From October 20, OAPEC countries decided one after another to impose an oil embargo on the United States, the Netherlands and other Israel supporters until Israel pulls out of the occupied Arab territories. On December 23, six Persian Gulf countries among the OPEC members decided to increase their posted oil price by 127.5% from $5.12/bbl to $11.65/bbl in January 1974. In response to these moves, the United States in principle banned the export of domestic crude oil in 1975 as a precaution against social unrest and energy shortages over OPEC's growing influence (and lifted the ban in December 2015).

With regard to the recapture of oil interests from international oil majors, there were two patterns for the governments of oil-producing country to take: in the first (moderate) pattern, they participated in oil business operations as partners of concession-holding contractors aimed at gradually expanding control. In the second (radical) pattern, they directly and quickly took back resources and business concessions from concession-holding international oil majors in the form of nationalization.

The Riyadh Agreement signed by Saudi Arabia and Abu Dhabi in December 1972 with international oil majors is a prime example of the first pattern case.

The second pattern or nationalization was seen in Algeria (1967), Libya (1970), Iraq (1972), Venezuela (1976) and Iran (1979), but the process and the form of the oil industry after nationalization varied by country.

3-3. Second half of 1970s to mid-1980s: Waning OPEC power -- Loosening oil supply-demand balance and emergence of futures market

Two major changes have occurred on the other side of OPEC's continued high oil price policy, shielding the strength of its members' cohesion and the superiority of supply and market share. One was a decline in oil demand, and the other was a surge in crude oil production in non-OPEC oil producing countries.

The first oil crisis (1973) triggered by Arab oil-producing countries' actions using oil as a weapon prompted industrial countries to recognize the need for their forum to discuss policy coordination among developed countries in macroeconomics, energy, currency, and trade policy and launched their annual summit meeting in 1975. At the Tokyo summit that came amid the second oil crisis triggered by the 1979 Iranian revolution, seven industrial countries resolved to hold down oil consumption, set oil import targets and promote the development of alternative energy sources. At the Venice summit in June 1980, they resolved to set targets for lowering oil's share of primary energy supply.

In addition, on the supply side, there were dramatic changes that would drive back the decline and sluggish demand for oil. OPEC's policy of keeping oil prices high artificially strongly supported investment in high-cost polar and deep-sea oil development and the commercialization of small oilfields. Alaska's Prudhoe Bay oilfield launched production in 1977, followed by full-blown North Sea oil development in the 1980s.

Furthermore, oil trading markets were formed from the late 1970s in addition to the conventional oil market dominated by self-contained physical transactions between oil-producing countries and international oil majors as sellers and oil-consuming country governments and end-users as buyers. Initially, parties to oil transactions used barter-type location swaps and time swaps of oil physicals to cut transportation costs and adjust the supply-demand balance to their mutual advantage. Later, however, brokers, as well as traders who took risks and conducted proprietary trading, entered the oil market. Public commodity exchanges and private over-the-counter markets were rapidly developed to handle futures and options in addition to physicals and forwards. In 1983, the New York Mercantile Exchange (NYMEX), a public exchange, listed West Texas Intermediate crude oil futures contracts, which have become an oil price benchmark. (New York Harbor No. 2

Heating Oil contracts became the first oil futures to be listed on NYMEX in 1978.) Subsequently, the International Petroleum Exchange (IPE) in London listed North Sea Brent crude oil futures contracts. Since then, the commoditization and financialization of oil accelerated, leading to the development of markets where oil producers, users, traders and other oil industry players could enjoy hedging functions against price fluctuations at their own risk and responsibility. In this way, oil pricing rights were transferred from international oil majors and OPEC to the invisible hands of markets including futures exchanges.

As a result, global oil demand turned downward as shown in Table 2, leading to oversupply. Some OPEC countries had no choice but to voluntarily cut production, and OPEC's share and market dominance weakened.

International oil majors that had lost oil pricing rights to OPEC were forced by the Iranian Revolution to lose exclusive concessions that they had defended under the rule of Shah Mohammed Reza Pahlavi since the formation of the Iranian Consortium in 1954. As the new Iranian regime after the revolution expanded direct dealings and spot sales with consumers, international oil majors' influence declined decisively after the second oil crisis.

Table 2 Changes in global primary energy demand, oil demand and OPEC supply after 2nd oil crisis

(Unit: million tons of oil equivalent) Source: BP Statistical Review 2019		**1973** 1st oil crisis	Change	**1979** 2nd oil crisis	Change	**1985**
Primary energy demand (A)		5,662.7	+1,021.5	6,684.2	+469.9	7,154.1
Oil (B)	Share: (B)/(A)	49.8%	▲2.1%	47.7%	▲7.2%	40.5%
	Demand	2,819.2	+367.8	3,187.0	▲289.1	2,897.9
OPEC (C)	Share: (C)/(B)	53.3%	▲6.4%	46.9%	▲19.9%	27.0%
	Supply	1,503.2	▲8.4	1,494.8	▲713.7	781.1

To briefly look back at the situation of Saudi Arabia, the leader of OPEC and the world's largest oil producer:

(1) Saudi Arabian crude oil production in 1983 was halved from more than 10 million barrels per day in 1980 and 1981 as Saudi Arabia lost some of its market share to other OPEC members and non-OPEC oil-producing countries. In 1985, production plunged to 3.6 million bpd.

(2) Saudi Arabia cut its official sales price of Arabian Light crude oil from $34/bbl in October 1981 to $30/bbl in February 1983 in its first ever oil price reduction. It lowered the price further to $29/bbl in February 1983 and to $28/bbl in February 1985 (Figure 4).

(3) As its oil revenue declined steeply due to production and price cuts, however, Saudi Arabia became unable to organize its budget. In July 1985, Saudi Arabia declared that it would no longer serve as a swing producer to adjust the crude oil supply-demand balance. In October of the same year, it launched the net-back pricing system to base crude oil prices on market prices of petroleum products in oil-consuming countries, before expanding production soon.
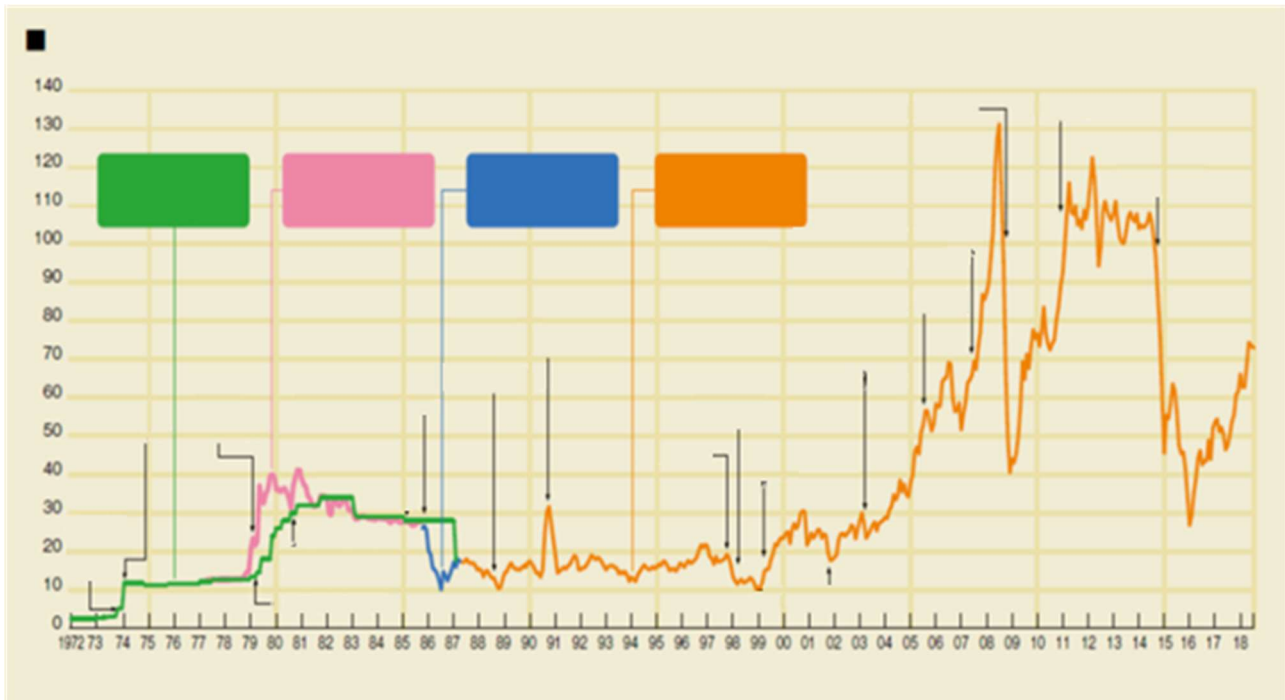
Fig.4   Crude oil price trend (1972-2018)

Source: Petroleum Association of Japan, "Today's Oil Industry 2018"

3-4. 1986 to 1990s: Market-based pricing – Progressing oil commoditization

Saudi Arabia's adoption of the net-back pricing system featured the epoch-making introduction of market principles into crude oil pricing. The Saudi Arabian policy turnaround allowed Saudi crude to recover its market share in the global downturn market but led to heavy price drops simultaneously. The spot North Sea Brent price plunged from $30/bbl in November 1985 to less than $20/bbl at the end of January 1986 and to $9.50/bbl in July of the same year.

Feeling a stronger sense of crisis, OPEC enhanced oil production cuts and called on non-OPEC oil-producing countries to join the production cuts in July 1986. Within and outside OPEC, calls grew gradually for stabilizing crude oil prices by adopting a fixed-price system.

In December 1986, OPEC decided to revive the fixed-price system on January 1, 1987, setting the weighted average of Arabian Light and six other crude oil brands at $18/bbl. It also set a production quota at 15.8 million bpd for the first half of 1987 and a tentative quota for the second half. From the beginning of 1988, OPEC began to adopt a spot price indexation system to index term contract prices to spot prices of specific crude oil brands. In the autumn of 1988, this system covered almost 80% of term contracts.

Since Saudi Arabia discontinued serving as a swing producer in the second half of the 1980s, oil has intensified its commoditization tendency to leave pricing to market principles and market "invisible hands." Throughout the 1990s, oil supply and demand fundamentals that form the backbone of market principles remained bearish, exerting downward pressure on oil prices, excluding the Persian Gulf Crisis period between August 1990 and March 1991 when a temporary market surge took place by such series of events as Iraq's invasion into Kuwait, the United Nations resolution tolerating armed attacks on Iraq, allied bombing on Iraq and the Gulf War ceasefire agreement. The Asian economic crisis, triggered by the currency plunge in Asia in July 1997, had a further impact on oil demand, and the oil market fell to a 12-year low in February 1999, the first time since the price crash in 1986 (Figure 4).

Since we Homo sapiens, who have evolved with the unique capability to believe in things existing purely in the imagination, the cognitive capacity for fiction, listed fictitious WTI futures contracts on NYMEX in 1983, the oil trading in the virtual market has grown rapidly and commoditization of the oil market has made great progress. The fictitious oil futures market that globally operates 24 hours a day like stock, bond and currency markets has been steadily developed,

reflecting the supply and demand position and market principles of the real economy in principle, and it has grown to become an essential part of the pricing mechanism for oil and natural gas.

4. Late 20th century to present

Starting with a major industry restructuring drama from the end of "the Century of Oil," the oil industry has recovered from a long-running market downturn cycle. Then, the surge in demand in emerging economies such as China and the shale revolution in the U.S. have created a high oil paradise for nearly 10 years. As the market has shifted into a downward cycle since 2014, the oil and gas market has become more diversified and quantitatively expanded by attracting non-oil related new players such as investment funds, and transformed into a more liquid and volatile market.

4-1. Late 1990s to mid-2000s: Realignment of IOCs – Escape from a long downturn cycle

As the downturn cycle has been prolonged for more than a decade, it was IOCs (International Oil Companies) that raised a sense of crisis over OPEC and NOCs (National Oil Companies).

They were well aware that to stay in the status quo would lead to a decline and that losers should immediately exit and keenly felt the need to make a bold reform. A drastic and unprecedented oil industry realignment including mergers and acquisitions between oil majors came between 1998 and the early 2000s. It was British Petroleum that took the lead.

- In December 1998, British Petroleum acquired Amoco for $55 billion and renamed itself as BP Amoco Plc.
- In September 1999, TotalFina acquired Elf for €52.6 billion in France and renamed itself as Total.
- In November 1999, Exxon acquired Mobil for $82 billion and renamed itself as ExxonMobil.
- In April 2000, BP Amoco acquired ARCO for $27 billion. (The U.S. Federal Trade Commission (FTC) approved the acquisition after ARCO spun off ARCO Alaska and sold it to Phillips for $7 billion.)
- In September 2001, Chevron acquired Texaco for $39.5 billion, as approved by the FTC.
- In August 2002, a merger between Conoco and Phillips into ConocoPhillips was approved by their shareholders and the FTC. The merged company's market capitalization totaled $18 billion.
- In August 2005, Chevron acquired Unocal for $17.9 billion. (After Chevron offered $16.5 billion for Unocal in April, China's CNOOC made a counteroffer of $18.5 billion in June. However, the U.S. Congress opposed the Chinese company's acquisition of Unocal for national security reasons.)
- In December 2005, ConocoPhillips acquired Burlington Resources Inc. for $33.8 billion.
- In October 2007 in Norway, Statoil annexed the oil and gas division of Hydro. (In 2018, Statoil renamed itself as Equinor.)

IOCs including oil majors materialized these big M&A deals boldly in a chain reaction to survive deteriorating business conditions through structural market changes and prolonged oil price stagnation. The realignment deals were generally designed to rationalize operations and enhance financial strength through upsizing and cost cuts and maintain or improve technological capabilities and stock prices. As both acquirers and acquirees were strongly alarmed about how to survive, these deals were cut through relatively short negotiations. As a result of the realignment, the Seven Sisters that had dominated the global oil market until the early 1970s were integrated into four groups – ExxonMobil, Royal Dutch Shell, Chevron and BP.

4-2. Mid-2000s to early 2014: Rapid oil demand growth in China and other emerging economies -- Burgeoning U.S. shale revolution

Soon after achieving a long-held desire to accede to the World Trade Organization (WTO) and join the market economy, China rapidly expanded oil and gas imports required for "the factory of the world" and rushed into overseas operations to secure oil and gas resources. (China took 15 years to realize its entry into the WTO after filing an application.) Other emerging market economies also expanded oil and gas demand for their remarkable economic growth from around 2002, allowing the 15-year sluggish downturn cycle to end. Competition for oil and gas resources as well as coal and uranium

emerged in the upstream sector. In the midstream and downstream sectors, global distribution flow began to structurally change. In addition to changes in supply and demand fundamentals driven by new oil demand, the 2003 Iraq War, Hurricane Katrina in 2005 and other factors interrupting stable oil supply came to usher in a high oil price period, when the spot Dubai crude oil price made a paradigm jump from $50/bbl to $70/bbl and to more than $100/bbl, as shown in Figure 4.

In 2008, the collapse of the housing bubble and the subprime loan problem sparked the collapse of Lehman Brothers, the fourth largest investment bank in the United States, triggered the global simultaneous recession that forced oil prices to plunge below $40/bbl (Dubai sank to $33.55/bbl). However, oil demand remained robust in China and other emerging market economies. Furthermore, amid a sharp decline in stock prices and a sharp fall in the currency following the Lehman shock, "wandering money" which grew due to liquidity enhancement measures taken by governments from around the world flooded the energy market as the safest and high-return investment target, encouraging oil prices to quickly spike back. With the massive influx of "wandering surplus money" into shale businesses in the United States, oil and gas fields development and LNG projects in various regions, investment decisions for various projects based on the assumption of sustained high oil prices have been realized.

In the energy commodity futures markets featuring high volatility and liquidity, the market environment has become more diversified and active due to the entry of speculative players such as hedge funds and the expansion of the size of funds. Futures and Options trading on public commodity exchanges such as New York and London are now inflated to tens of times the physical supply and demand volume of the real economy, making it an integral part of the oil pricing mechanism. In three years to 2018, daily average WTI futures trading volume rose to 1.1-1.3 billion barrels, over 10 times more than global crude oil production at about 98 million bpd.

On the supply side as well, a great structural change came in the second half of the 2000s. That is the U.S. shale revolution. According to BP Statistical Review, the United States, though having turned a net oil importer in 1948, kept its production level above 10 million bbl (including 1.5-2.0 million bpd in natural gas liquids or NGLs) in 18 years of the 1967-1986 period excluding 1976 and 1977 and remained the largest oil producer in the free world (excluding the former Soviet bloc) until it lost the position to Saudi Arabia in 1980. As the depletion of operating oilfields was coupled with constraints on new oil and gas development by social demands to protect the environment and respond to global warming, U.S. oil production declined year by year and slipped below 7 million bpd in 2005. In such situation, technological innovation burgeoned to allow unconventional oil and gas resources trapped in shale layers to be extracted. The innovation produced the core fracturing or fracking technology to inject ultra-high-pressure liquids into rock formations containing shale gas and tight or shale oil to generate artificial fractures and release gas and oil from rock formations with low penetration rates. The advancement of a horizontal drilling technology to widen the exposure of the fractured rock to a well bore and a micro seismic technology to detect progress in fracturing allowed gas and oil collection rates to increase further, triggering an unconventional resource development boom for ground shale layers where drilling costs are lower.
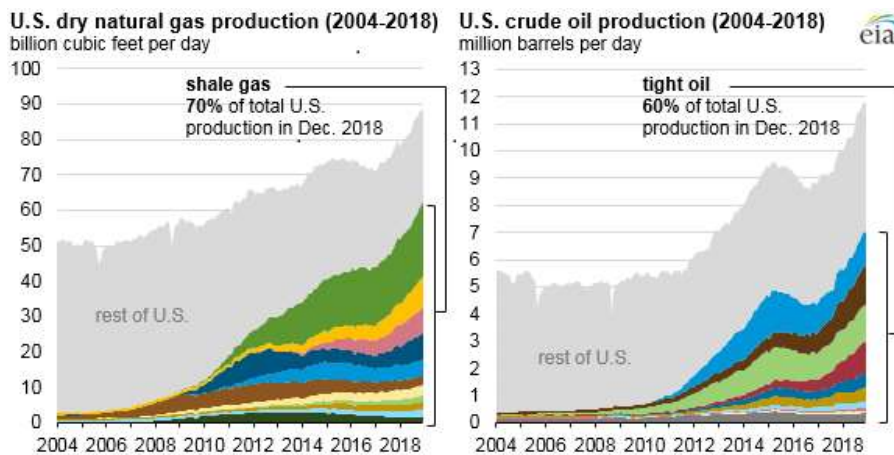

Fig. 5   U.S. natural gas and crude oil production trends (2004-2018)

Source: U.S. Energy Information Administration

The shale revolution led U.S. natural gas and crude oil production to rapidly expand as shown in Figure 5. U.S. oil production rose back to 7.263 million bpd (including 2 million bpd in NGLs) in 2009 thanks to growing tight oil production. Tight oil production increased further later, accounting for 60% of total U.S. oil production that rose above 15 million bpd (including 4.36 million bpd in NGLs) in 2018. Unconventional shale gas now captures 70% of U.S. natural gas production.

4-3. Late 2014 to present (2019): Dawn of low-carbon or decarbonized society – Challenging complicated risks

Although the U.S. shale revolution began to exert great influence on the global oil supply structure around 2006, rapid oil demand growth in China and other emerging market economies allowed oil supply and demand in the real economy to rise in a balanced manner, with oil prices remaining high. Wandering surplus money growing since the Lehman failure flew into the oil and gas market, transforming the market into a more volatile one.

China, whose economy has boomed rapidly since joining the WTO, has led the global economy, including aggressively entering resource acquisition competition and overseas asset acquisitions to encourage over-competition and market inflation, but since the beginning of the 2010s, its economic growth has slowed down year after year.

The developed countries were gradually taking off from the aftereffects of the Lehman shock but the energy consumption growth in Western countries and Japan was trivial. The fierce race for natural resources and new oil and gas development investment decisions depended completely on robust oil demand in emerging market economies including BRICs (Brazil, Russia, India and China). However, as economic growth in China and other emerging market economies began to slow down or stagnate, bullish energy demand forecasts were revised substantially downward. In the middle of 2014, excessive crude oil inventories and oversupply surfaced, and the high oil price market, which has continued since the early 2000s, has plummeted.

There have been two patterns of oil market crashes since spot and futures markets were launched in the 1980s. One pattern represents crashes triggered by the 1998 Asian currency crisis and the 2008 Lehman failure. These crashes caused by the financial crises were followed by rallies in a relatively short term. The other pattern represents crashes attributable to weak supply and demand fundamentals, including the current crash as well as the downturn cycle that lasted for more than 10 years from 1986 to the early 2000s. An oil supply-demand imbalance or excess inventories emerged in the autumn of 2014 and lasted until the spring of 2018 when supply and demand were rebalanced once. At an OPEC meeting in July 2019, however, oversupply was feared again, indicating that we are still in a downturn cycle.

As a standard indicating a proper inventory level, OPEC has adopted an average crude oil inventory level for the latest five years in the member countries of the Organization for Economic Cooperation and Development. However, the OECD countries accounted for only 48-49% of global oil demand in the latest five years. We may have to remember that the international community is discussing whether supply and demand are rebalanced or not, based on these developed countries' various dynamic data (that may be evenly accurate and based on even statistical methods) and those provided by China, India and other non-OECD countries that use their respective unique statistical methods.

The current downturn cycle has had a major difference with the previous one. Due to the expansion of both asset and debt in the high oil price environment, a considerable number of IOCs including majors and oil-producing countries have been plagued with overleveraged financials.

In the high oil price environment before the current downturn cycle, NOCs and IOCs boasted of massive cash revenues to easily cover massive capital spending on and loan repayments for ongoing projects. Amid the downturn cycle, however, they have faced an unprecedented situation where they have difficulties in day-to-day cash management as their cash flow has turned negative with heavy losses. They have suspended ongoing projects to save cash spending. Global investment in the upstream oil and gas sector plunged in 2015 and 2016 for the first two-year downturn in 30 years. Investment has turned up since 2017 but remained far below levels before 2014. As operating oil and gas fields are being depleted, the sluggish investment is feared to exert serious negative effects on the future maintenance or expansion of supply capacity.

After investing in the sector aggressively in the high oil price environment, investors and financial institutions have suddenly changed their attitude, mercilessly implementing immediate investment withdrawals, additional security requests

and lending quota revisions.

Moreover, rating agencies such as S&P and Moody's have lowered credit ratings for oil-producing countries and IOCs including majors. Credit ratings by these agencies, though only representing opinions on debt repayment capabilities, are significant, objective and influential indicators reflected in lenders' loan decisions and borrowers' fundraising costs. The credit rating cuts soon forced less creditworthy U.S. shale companies to go bankrupt, throwing the oil industry into a survival race.

In a bid to survive as winners, international oil majors have quickly tried to improve their unprecedentedly vulnerable financials by giving top priority to the early restoration of positive free cash flow and balance sheet rebalancing. They have commonly tackled spending saving measures including personnel and cost cuts, capital investment restrictions, business portfolio and investment discipline optimization, selling of non-core assets and revisions to agreements with contractors. However, they have refrained from reducing shareholder returns (dividends and share buybacks).

On this occasion, the majors have also begun to energetically change the way of thinking among executives and regular employees for enhancing organizational strength and tackle digitalization to further improve their technological supremacy. At the same time, they are fiercely competing to transform into corporations that tackle difficult challenges such as global warming, social requirements for low-carbonization and decarbonization, the ESG (environment, society and governance) investment trend and coexistence with core businesses.

5. Future oil and gas market

As the 21st century opened, an age came for both industrial and developing countries to discuss how to reduce their dependence on fossil fuels, which account for about 80% of primary energy supply, and how to take relevant actions on a global scale. Given the mainstream theory that global warming is attributable mainly to anthropogenic greenhouse gases emitted through human industrial activities, including carbon dioxide that is increasing due mainly to human fossil fuel consumption, fossil fuel phase-out, low-carbonization and decarbonization initiatives have been accelerated in recent years to spread electric vehicles, switch to renewable energy such as solar photovoltaics, wind and biomass and promote energy efficiency improvements.

About 160 years have passed since the oil industry emerged in the United States. About 60 years have passed since oil replaced coal as the main primary energy fuel. The countdown has started for the timing for oil or gas to lose its current position within the coming half century. Oil demand is likely to peak as early as in the 2030s. In view of such business environment, the oil and gas upstream sector may be increasingly required to give greater consideration to environmental risk factors and pivot from the supply side to the demand side (Figure 6).
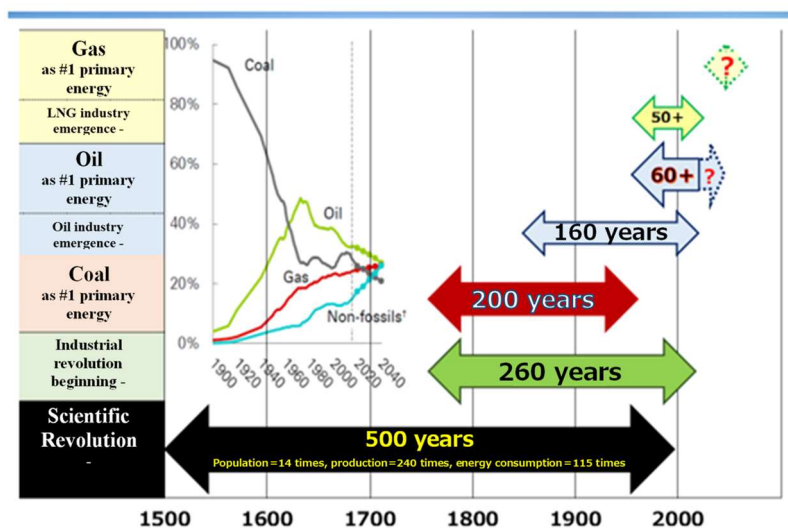

Fig. 6   Energy chronology from Scientific Revolution (1500)

Sources: Graph from BP Energy Outlook 2018, table prepared by the author from various information

As discussed later in 5-2., fossil fuels are indispensable for non-combusted use or raw material application for petrochemical production and the like. Unless alternative raw materials for petrochemicals are found, it would be impossible to realize a world that does not depend on fossil fuels at all. Realistically, the optimum solution would be to explore the best energy mix to minimize the fossil fuel share while expecting energy sources to be further diversified through such technological innovation as artificial intelligence and Internet of Things technologies.

Lastly, having looked back on the changes of major players and the transitions in the market since the birth of the oil and gas industry, it seems that three notable perspectives in looking ahead have come into view as follows.

5-1. Gas to become main primary energy fuel

As global warming and environmental protection have been emphasized and closely watched as key global challenges since the end of "the Century of Oil," demand for natural gas, which has relatively low CO_2 emissions, is growing steadily as the primary energy source with the highest advantage among fossil fuels.

In its Energy Outlook 2019, BP gives the Evolving Transition reference scenario in which gas demand is projected to increase at an annual rate of 1.7% (against 0.3% for oil and minus 0.1% for coal). Natural gas is predicted to replace coal as the No. 2 primary energy fuel in the mid-2020s and compete for the No. 1 position of primary energy fuel with non-fossil fuels and oil in 2040 (Figure 7). Non-fossil fuels are forecast to post the highest growth in the coming two decades.
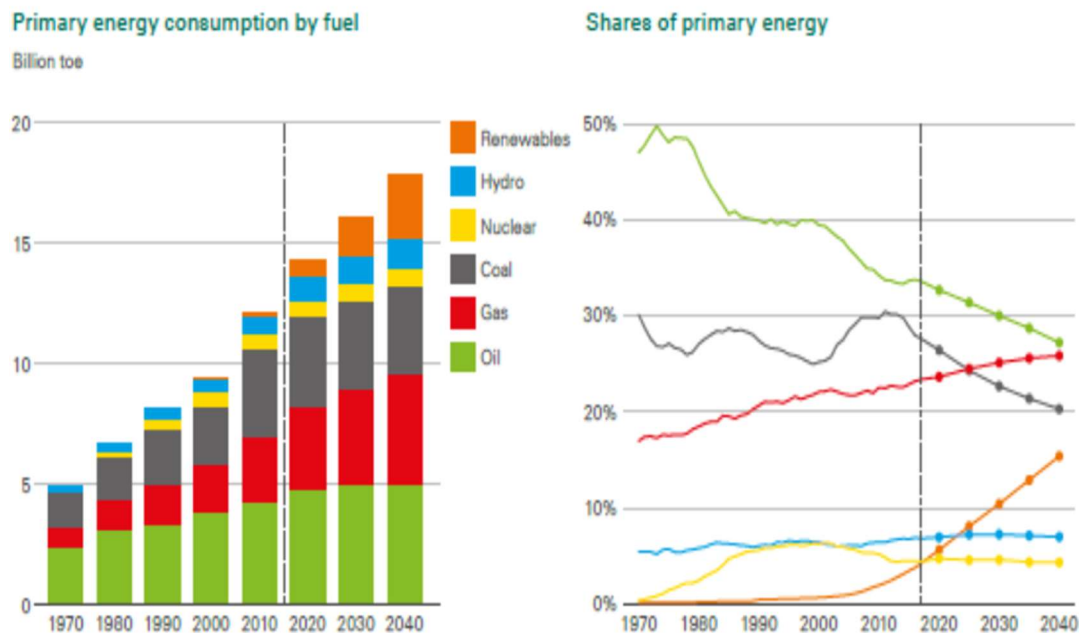

Fig. 7   Primary energy consumption by fuel and shares
Source: BP Energy Outlook 2018, 2019

While gas demand is expected to sustain growth due to energy demand expansion in emerging market economies accelerating industrialization and fuel switching to gas, supply is projected to rise in the United States, Qatar and Iran. Gas production in 2040 is predicted to increase by nearly 25% in the United States and by 20% each in the Middle East and the Commonwealth of Independent States. In international trade, liquefied natural gas trade is projected to exceed pipeline gas trade in the second half of the 2020s. LNG trade in 2040 is estimated to more than double from the current level to 900 billion cubic meters (660 million tons), accounting for more than 15% of global gas demand.

5-2. Oil to be focused on non-energy or non-combusted use

BP in its Energy Outlook 2017 reclassified the end-user sector of primary energy demand by creating the "non-combusted use sector" for feedstock usage of fossil fuel in petrochemicals, lubricants, asphalt and tar. Those non-fuel uses had

previously been classified in the industry sector. Most of the non-combusted feedstocks are derived from oil, but some belong to gas and coal.

At present, the industry sector (including petrochemicals, etc.) accounts for about 50% of primary energy demand, the buildings sector for 29% and the transport sector for 21%. The transport sector's energy demand is expected to substantially decelerate growth due to the spread of electric vehicles. In the Evolving Transition scenario, the non-combusted use sector's demand is projected to increase by 7 million bpd to 22 million bpd in 2040 as demand for oil for petrochemicals expands. This increase is the largest among sectors. That is why the non-combusted use sector was separated from the industry sector (Figure 8).
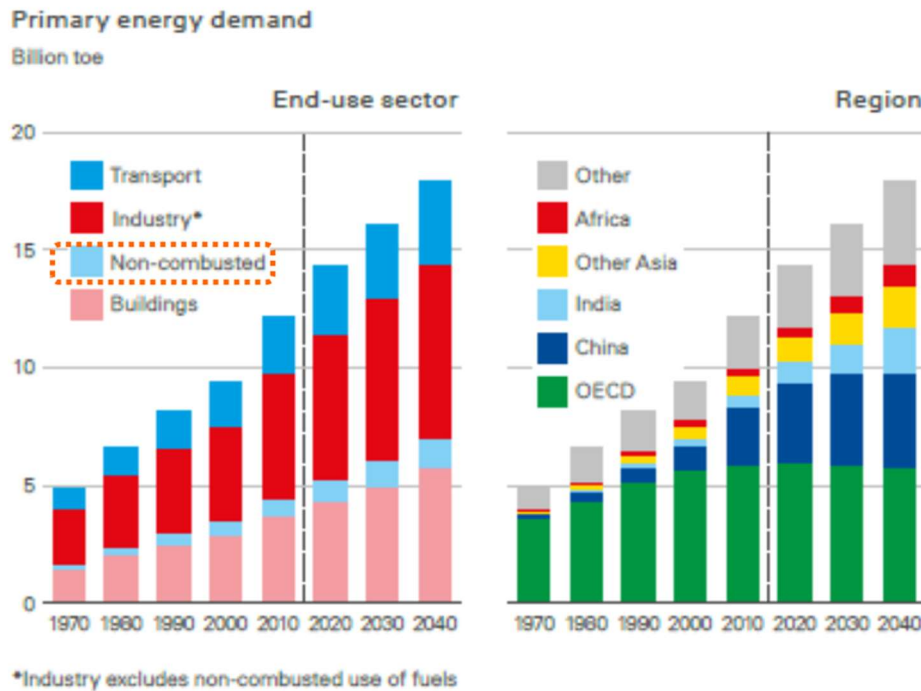

Fig. 8   Primary energy demand by end-use sector and region
Source: BP Energy Outlook 2019

5-3. U.S. regaining supremacy?

Figure 9 is a long-term outlook (an excerpt covering up to 2040) on U.S. crude oil and NGLs production given in the Annual Energy Outlook 2019 released by the U.S. Energy Information Administration in January 2019. In both the Reference Case and Low Oil & Gas Resource + Technology Case, U.S. crude oil and NGLs production is projected to maintain high levels above the present level of 15 million bpd over a long term.

The United States turned a net oil importer in 1948, banned crude oil exports in principle (light crude oil exports to Canada were exceptionally permitted) in response to energy shortages in 1975 after the first oil crisis and lifted the 40-year ban in December 2015. In several years, the United States is very likely to turn a net oil exporter for the first time in more than 70 years.

The United States became an LNG exporter in 2016 and may replace Australia as the second largest LNG exporter after Qatar in the near future. (Other LNG exporters include Russia and Africa.)

As U.S. oil and gas production is expected to expand further, New York's trading volume and roles for financial instruments including oil and gas futures and derivatives are likely to increase more and more.

Given the above, the United States is increasingly likely to regain supremacy in the oil and gas industry which emerged in the country in the second half of the 19th century, some 160 years ago.
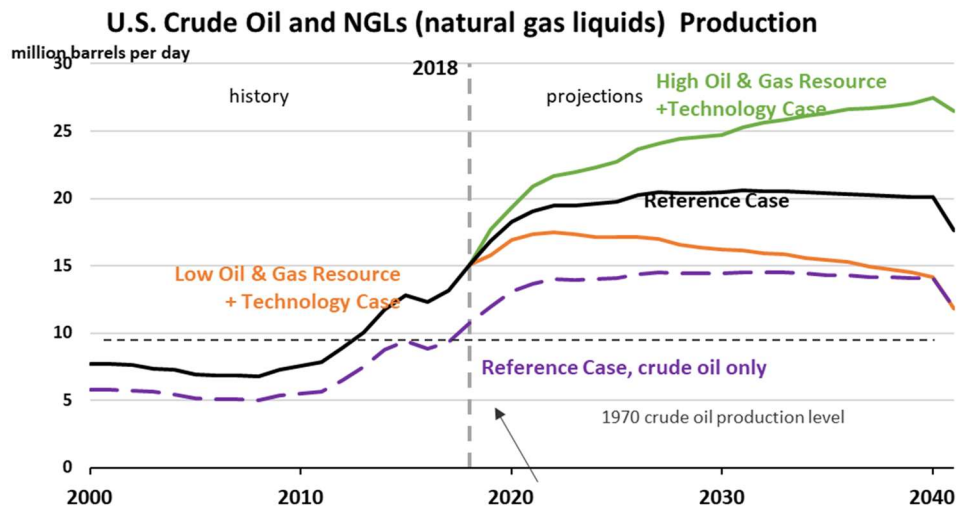
U.S. Crude Oil and NGLs (natural gas liquids) Production

Fig. 9   U.S. crude oil and NGLs production results and forecasts (2000-2040)

Source: Energy Information Administration

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Major players in the Australian coal industry and factors influencing thermal coal pricing for Japan

Jun Yoshimura *

1. Introduction

Coal—whether used as a fuel or in the steelmaking process—has been behind the scenes, powering the world economy and promoting the development of modern society for centuries. Its use has also come under increasing criticism over the last couple of decades as governments, private enterprises and other organizations have come to recognize anthropogenic climate change as a top priority and make efforts to reduce greenhouse gas emissions. However, coal's global abundance ensures supply stability, and as long as it retains its competitive edge over other energy sources, it is likely to continue playing a major role in the energy mix in Japan[1] and many other parts of the world for years to come. Growth in demand for steel may also make the use of coal in the blast furnace ironmaking process inevitable.

Focusing on Australia[2] —Japan's largest and most stable supplier of high quality coal—this essay outlines the history of the Australian coal industry and its major players before turning to focus on Japanese power utilities (JPUs), the largest thermal coal consumers in Japan. Australian thermal coal procurement by Japan and the pricing of this coal are also analyzed to gain an understanding of the sales and purchase process.

2. Brief history of the Australian coal industry

According to Australian government records, coal was discovered in Australia in 1791 by an escaped convict near the site of Newcastle[3] in eastern New South Wales (NSW). Coal mining commenced there in 1799 and Australian coal was first exported—from Newcastle to British-ruled India—the same year[4]. Although commercial coal production had commenced in every Australian state by 1898[5], the states of NSW and Queensland (QLD) became the centers of coal mining in Australia because of their more plentiful deposits[6].

Japanese companies played key roles as buyers and financiers of the development of coal mines and in the sharp expansion of Australian coal production and export that began in the mid-to-late 1950s. Two primary factors powered the increase. First, the rebuilding of Japan after the Second World War led to the development of large mines in QLD, and coking coal exports to Japan started in 1959 to fulfill growing steel demand[7]. Mitsui & Co., a Japanese trading house, partnered with Thiess, an Australian company, and Peabody, an American company, in the 1963 development of the Moura mine, contributing financing and then selling the coal to Japanese consumers[8]. This was the first joint development project

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[1] According to the 5th Strategic Energy Plan formulated by the government of Japan (approved by the Cabinet in July 2018), coal is expected to account for approximately 26% of Japan's power generation mix in 2030.

[2] Japan imported 192.84 million metric tons of thermal coal in Japanese Fiscal Year (JFY) 2017, of which 62% (119.13 million metric tons) was from Australia.
TEX Report; 2018 Coal Yearbook (written in Japanese), p.46

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[6] Productivity Commission; op.cit., p.C3.

[7] Productivity Commission; op.cit., p.C2.

[8] Australian Trade and Investment Commission; Japanese Investment in Australia, July 2017, p.12.
https://www.anzccj.jp/resources/Documents/Austrade%20-%20Japan%20Investment%20in%20Australia%20-%20launced%2028%

in Australia by a Japanese company and a model for later foreign investment in the Australian resource sector[9]. The second major factor that promoted the development of Australian coal production was surging oil prices during the two oil crises of the 1970s. This led to the rediscovery of coal as an alternative fuel and a rapid increase in Australian thermal coal exports[10].

Fig. 1   Commonwealth of Australia

Source: CIA website

3.   Major players in the Australian coal industry over time

The roughly 230-year history of the Australian coal industry can be divided into five periods.
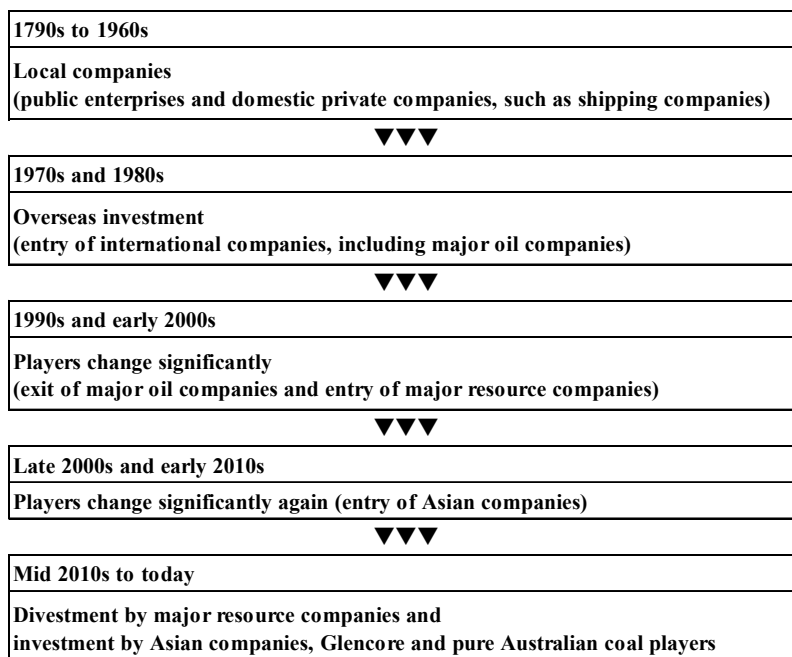
1790s to 1960s
Local companies   **(public enterprises and domestic private companies, such as shipping companies)**

▼▼▼

1970s and 1980s
Overseas investment   **(entry of international companies, including major oil companies)**

▼▼▼

1990s and early 2000s
Players change significantly   **(exit of major oil companies and entry of major resource companies)**

▼▼▼

Late 2000s and early 2010s
Players change significantly again (entry of Asian companies)

▼▼▼

Mid 2010s to today
Divestment by major resource companies and   **investment by Asian companies, Glencore and pure Australian coal players**

Fig. 2.   Development of the Australian coal industry

20July%202017.pdf#search=%27Nippon+Steel+Australia+investment%27

[9] Mitsui & Co. https://www.mitsui.com/au/en/company/history/index.html

[10] Productivity Commission; op.cit., p.C2.

Bill McKay, Ian Lambert and Shige Miyazaki, Australian Geological Survey Organization; The Australian Mining Industry: From Settlement to 2000, October 2000.

https://www.abs.gov.au/ausstats/abs%40.nsf/94713ad445ff1425ca25682000192af2/93136e734ff62aa2ca2569de00271b10!OpenDocument

3-1. From 1790s to 1960s: local companies

Starting in the late 18th century, private companies were the leaders in developing and operating coal mines while some public enterprises served complementary roles by operating some mines[11]. The capital injected was overwhelmingly local as late as the 1960s; little overseas investment had taken place other than England's investments when Australia was a British colony. During the 1950s and 1960s, the Australian coal industry saw widespread consolidation and a resulting aggregation of coal resources[12].

Several developments in NSW during this period affected the development of the Australian coal industry. The NSW colonial government established some coal mines during the 1810s and 1820s before selling them to the Australian Agriculture Company (AAC)—established in England—in 1830[13]. During the 1840s, Australian private companies, such as J. and A. Brown (JAS)[14], entered the market to challenge AAC's coal production monopoly. Shipping companies based on the Australian coast who transported coal by steamship invested in the development of coal mines, which required huge amounts of capital. Howard Smith[15], an Australian shipping company, purchased a British company called Caledonian Coal and founded Caledonian Collieries in Australia; it then promoted both shipping and coal mining as its core businesses. Another Australian shipping company, Adelaide Steamship, acquired a major share of coal mining operations in the Hunter region of NSW in the late 19th century and established Abermain Seaham Collieries (ASC) in 1922. The 1931 merger of ASC and JAS gave birth to J. and A. Brown and Abermain Seaham Collieries (JABAS)—the largest coal company in Australia throughout the 1950s. JABAS and Caledonian Collieries—a subsidiary of Howard Smith—were incorporated into Coal & Allied Industries (C&A), a major Australian coal company, in 1960[16]. The top three companies' share of coal production in NSW increased from 56% (BHP, C&A and a state-owned enterprise) in 1960 to 60% (a state-owned enterprise, BHP and Clutha) in 1970, and the aggregation of coal resources by major domestic companies in NSW likewise advanced[17].

3-2. 1970s and 1980s: entry of international companies, including major oil companies

Australian companies continued to dominate the Australian coal industry during the 1970s and the 1980s. The current major mineral resource companies, BHP[18] and Rio Tinto (formerly CRA)[19], were already significant coal producers by this time. In NSW, domestic companies were responsible for about two一-thirds of total coal production and C&A[20] was

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[11] John Wilkinson; Coal Production in New South Wales, Briefing Paper No 10/95, March 1995, p.7.

https://www.parliament.nsw.gov.au/researchpapers/Documents/coal-production-in-new-south-wales/Coal%20Production%20in%20New%20South%20Wales.pdf#search=%27Coal+Production+in+New+South+Wales%27

[12] John Wilkinson; op.cit., p.17.

[13] https://aaco.com.au/about-us/our-history

[14] John Wilkinson; op.cit., p.17.

[15] https://en.wikipedia.org/wiki/Howard_Smith_Limited

[16] John Wilkinson; op.cit., p.17.

[17] John Wilkinson; op.cit., pp.17-18.

[18] BHP Group Limited is the largest mining company in the world, mainly listed on the Australian Stock Exchange and the London Stock Exchange. BHP is an abbreviated expression of its original name, Broken Hill Proprietary Company Limited. It was originally founded as a copper mining company in Broken Hill, a city in southwestern NSW. In 2001, it merged with Billiton, a British mining company, and changed its name to BHP Billiton. In 2018, it changed its name again to BHP Group.

[19] CRA was a subsidiary of RTZ, a British mining company, and was originally listed on the Australian Stock Exchange. It merged with RTZ in 1995. The merged company, RTZ-CRA, was listed on London Stock Exchange and the Australian Stock Exchange and changed its name to Rio Tinto in 1997.

[20] C&A's largest shareholder in 1990 was Howard Smith with 42.1%. This changed when CRA purchased 70% of C&A's shares in 1991. BXG, Inc. in association with Barlow Jonker, Pty. Ltd.; Australian Coal 1990 Update, p. II-43.
John Wilkinson; op.cit., p.18.

the largest producer during the 1980s[21].

International oil companies entered the Australian coal industry during this period in search of new opportunities to diversify in response to the drastically changed business environment in the wake of the first and second oil crises. The first major entrant was BP with its purchase of Clutha—the largest coal exporter in NSW—in 1977-78. Shell then acquired three Australian coal mining companies between 1977 and 1979[22]. Other oil companies, such as ExxonMobil (formerly Exxon), Chevron (formerly Caltex), ARCO (acquired by BP in 2000), Eni (formerly Agip) and Total, followed suit[23]. The first two entrants, BP and Shell, were the most aggressive. By 1982-83, they ranked third and fourth, respectively, in NSW coal production after Howard Smith and BHP[24]. However, they remained active in the Australian coal industry for very different lengths of time. BP left the market in 1989 when it sold its global mineral resource business—including its Australian coal business—to Rio Tinto[25]. Shell, by contrast, continued to be one of the top coal producers in Australia until the beginning of the 21st century.

3-3. 1990s and early 2000s: exit of major oil companies and entry of major resource companies

By the mid-1990s, coal prices had stabilized at between $45 and $53 per metric ton (MT) FOB Australia for hard coking coal—the highest ranked coal for steelmaking purposes—and at $34 to $41 per MT FOB Australia for thermal coal. Coal supply and demand were well balanced in the market as producers increased coal supply in a timely fashion to meet growing demand, mainly in Asia.
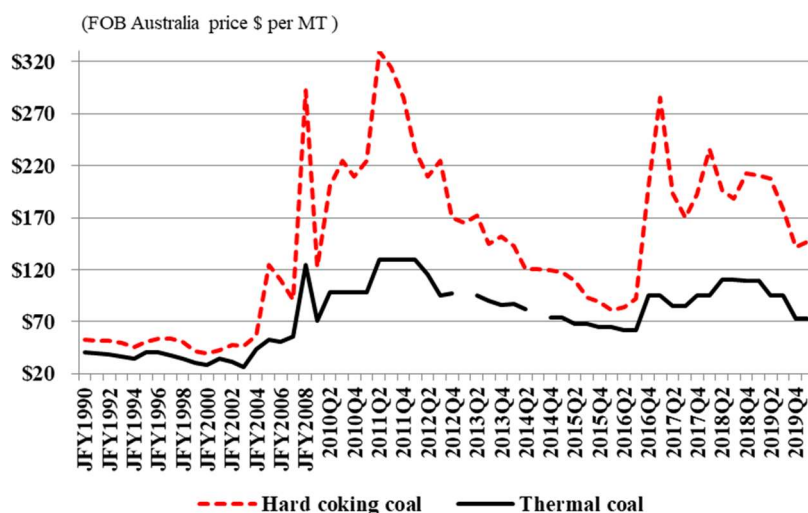

Fig. 3   Price movement in Australian term-contracted coal from 1990 to 2019

(Source) TEX Report; 2018 Coal Yearbook (in Japanese)

Energy Economic Center; Environment, Energy/Coal & Power Report (in Japanese)

IHS Markit; Australian Coal Report

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[21] John Wilkinson; op.cit., pp.17-18.

[22] Shell purchased interests in Austen & Butta and Thiess Holdings in 1977 and in Bellambi Coal in 1979. John Wilkinson; op.cit., p.18.

[23] NSW Department of Mineral Resources; Coal in New South Wales, Industry Profile 1984

NSW Department of Minerals and Energy; New South Wales Coal Industry Profile 1989, Statistical Information to June 1988

John Wilkinson; op.cit., pp.18-19.

[24] NSW Coal production in Australian Fiscal Year 1982/83 was 63.4 million metric tons. The top four producers were Howard Smith (15%), BHP (13%), BP (9%) and Shell (7%).

NSW Department of Mineral Resources; op.cit.

[25] John Wilkinson; op.cit., p.17.

Table 1. Top 10 coal producers in Australia in 1993

No.	Producers[1]	Production share[2]	Reference (Nationality / Major business area other than coal business, etc.)
1	BHP	25.2%	Australia / Iron ore, Non-ferrous metal ore, Petroleum
2	CRA	18.6%	Australia / Iron ore, Non-ferrous metal ore / Merged with its parent company, RTZ, in 1995 and renamed to Rio Tinto in 1997
3	Shell	7.6%	UK & Netherlands / Petroleum / Abandoned coal business in 2000
4	Powercoal	5.5%	Originally owened by the NSW state power / Acquired by Centennial Coal in 2002
5	Oakbridge	5.3%	Australia / Glencore acquired a major share in 2000
6	MIM	5.3%	Australia / Non-ferrous metal ore / Acquired by Glencore in 2003
7	Peabody	4.8%	USA / Withdrew from the Australian coal industry in 2001 and re-entered in 2002
8	ARCO	3.9%	USA / Petroleum / Abandoned coal business in 1998-99. Acquired by BP in 2000
9	Exxon	3.5%	USA / Petroleum / Abandoned coal business in 2000
10	Oceanic Coal	2.2%	Australia / Acquired by Glencore in 1999
Top 3 producers' share 51.5% / Top 5's share 62.3% / Top 10's share 81.9%			

*1: Company name in 1993

*2: Total of thermal coal and coking coal on a saleable coal basis

(Source) Australian Coal Report, COAL 1995

However, as a result of the Asian economic crisis in 1997, extreme oversupply emerged in the coal market. Hit hard by both significantly falling demand and prices, some producers underwent restructuring and sold their coal assets. Most of the major oil companies, such as Shell and Exxon, withdrew from the coal business around the year 2000. On the other hand, major resource companies like Rio Tino, Glencore and Anglo American believed that the market would recover and that coal demand would grow in the future, and used the low prices as an opportunity to actively purchase coal assets. The other major resource companies, BHP and Billiton, merged in 2001 to expand their bases of operations. The largest American coal miner, Peabody, is a unique example: it exited the Australian coal industry in 2001 but almost immediately re-entered in 2002 and it remains a player in Australian coal now.

Table 2. Top 10 coal producers in Australia in 2004

No.	Producers[1]	Production share[2]	Reference (Nationality / Major business area other than coal business, etc.)
1	BHP Billiton	23.5%	Australia & UK / Iron ore, Non-ferrous metal ore, Petroleum
2	Rio Tinto	19.1%	Australia & UK / Iron ore, Non-ferrous metal ore
3	Xstrata	18.5%	Glencore's subsidiary / Merged with Glencore in 2013
4	Anglo American	10.5%	UK / Non-ferrous metal ore, Precious metal / Acquired coal business from Shell in 2000
5	Centennial Coal	4.5%	Australia / Acquired by Banpu in 2010
6	Wesfarmers	3.4%	Australia / Conglomerate / Abondoned coal business in 2017
7	Idemitsu	3.2%	Japan / Petroleum / Merged with Showa Shell in 2019
8	Macarthur Coal	2.3%	Australia / Acquired by Peabody in 2011
9	Peabody	2.1%	USA / Withdrew from the Australian coal industry in 2001 and re-entered in 2002
10	Excel Mining	1.6%	Australia / Acquired by Peabody in 2006
Top 3 producers' share 61.0% / Top 5's share 76.0% / Top 10's share 88.6%			

*1: Company name in 2004

*2: Total of thermal coal and coking coal on a saleable coal basis

(Source) Barlow Jonker, COAL 2005

3-4. Late 2000s and the early 2010s: entry of Asian companies

A quote attributed to the famous American writer Mark Twain applies well to the Australian coal industry: "History doesn't repeat itself, but it does rhyme."

The Lehman shock in 2008 brought significantly reduced coal demand and prices to the Australian coal industry—very similar to the Asian economic crisis in 1997. It is noteworthy, however, that many of the companies that purchased coal assets in the aftermath of Lehman were originally from Asian countries such as China, Thailand and India.

Table 3. Major sales and purchases of Australian coal assets from the late 2000s to the early 2010s

	Buyer (Nationality)	Coal assets	Seller (Nationality)
2009	Yancoal (China)	Felix Resources	Felix's shareholders
2010	Banpu (Thailand)	Centennial Coal	Centennial's shareholders
	Sojitz (Japan)	Minerva mine	Yancoal (China)
	Adani (India)	Carmichael project	Linc Energy (Australia)
2011	Yancoal (China)	Gloucester Coal	Gloucester's shareholders
	Peabody (USA)	Macarthur Coal	Macarthur's shareholders
2012	Whitehaven (Australia)	Aston Resources	Aston's shareholders
2013	Jindal Steel & Power (India)	Gujarat NRE Coke	Gujarat (India)

In section 2 above, I mentioned the key role Japanese companies played as buyers and financiers in the development of the Australian coal industry. Korean companies began playing a similar role in the industry in the 1980s. Japanese and Korean companies participated in most coal-related projects as minor partners, but Asian companies did not usually seek to

acquire greater than 50% equity—and therefore operational control—of projects. Idemitsu (starting around the 1990s) and Sojitz (since the 2010s) were exceptions to this. Post-Lehman, Asian companies often purchased controlling shares of companies or projects to gain operational control.

3-5. Mid-2010s to today: divestment by major resource companies and investment by Asian companies, Glencore and other pure Australian coal players

During this period, companies in the Australian coal industry approached changing investment and lending behavior in three ways, giving greater consideration to the ESG (environmental, social and governance) concerns of investors and lenders amid continuing low prices, particularly for thermal coal.

- Exiting the industry

    Rio Tinto announced its decision in 2013 to sell its steaming coal assets because of the long-lasting price slump. Given the growing need for a low-carbon economy in the future, Rio decided to sell its coking coal assets as well and then sold all of its coal-related assets between 2014 and 2018, withdrawing from the coal industry. An Australian conglomerate, Wesfarmers, also sold off its coal assets and exited the coal industry.

- Continuing or expanding the coking coal business but quitting or downsizing the thermal coal business

    BHP spun off its thermal coal business in South Africa and its coking coal business in NSW in 2015 to form South32 and is reportedly looking to sell its remaining thermal coal assets in NSW and Columbia.

    South32 purchased 50% equity in a coking coal project in QLD in 2018 while working to sell its steaming coal assets in South Africa.

    Although Anglo American remains in the coking coal business, it announced plans to sell off its steaming coal assets in 2015 and finally did so in 2016.

    Some Japanese trading houses have sold their thermal coal assets while retaining or even trying to expand their coking coal businesses.

- Remaining in or entering the Australian thermal coal business

    Glencore announced in February 2019 that it would expand its coking coal business and continue its thermal coal business, but that it would not increase thermal coal production from current levels in recognition of the growing need for a lower carbon economy[26]. Yancoal Australia, backed by a major Chinese coal company, purchased C&A from Rio Tinto and became the second largest thermal coal producer in Australia after Glencore.

Adaro Energy, a major Indonesian coal company, bought a coking coal mine in Queensland from Rio Tinto with the support of a private equity fund.

Salim Group, a major Indonesian business group, purchased a steaming coal project in NSW from Rio Tinto through its subsidiary, MACH Energy.

Pure Australian coal players such as New Hope and Whitehaven have expanded their business portfolios by purchasing existing coal mines and/or developing new mines.

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[26] https://www.glencore.com/media-and-insights/news/Furthering-our-commitment-to-the-transition-to-a-low-carbon-economy

Table 4. Major sales and purchases of Australian coal assets from the mid-2010s to today

	Buyer (Nationality)	Coal Assets	Seller
2014	Glencore (Switzerland) / Sumitomo Corporation (Japan)	Clermont mine (50.1%)	Rio Tinto
2015	Investors	South32 spin-off	BHP
2016	New Hope (Australia)	Bengalla mine (40%)	Rio Tinto
	MACH Energy (owned by Salim Group in Indonesia)	Mt. Pleasant project	Rio Tinto
	Trust Fund Management (Australia)	Foxleigh mine	Anglo American
	Batchfire Resources (Australia)	Callide mine	Anglo American
2017	Yancoal	C&A	Rio Tinto
	Glencore	C&A's Hunter Valley mine (49%)	Yancoal
	Coronado Coal (USA)	Curragh mine	Wesfarmers
2018	Glencore	Hail Creek mine, etc.	Rio Tinto
	Adaro Energy (Indonesia), etc.	Kestrel mine	Rio Tinto
	New Hope	Bengalla mine (40%)	Wesfarmers

4. Marketing and pricing of Australian thermal coal for Japan

As mentioned above, JPUs are the largest thermal coal consumers in Japan. At the third ministerial meeting of the International Energy Agency (IEA) held in May 1979 after the second oil crisis, the "Principles for IEA Action on Coal" were agreed upon while the building or replacement of oil-fired base load power plants by the IEA member countries was prohibited[27]. To accommodate the IEA's decision and meet increasing demand for electric power, JPUs created action plans to build coal-fired power plants which started coming online in 1986. Demand by JPUs and their need for stable long-term supplies have strongly supported the operations of Australian coal suppliers. Due to the magnitude of their demand, coal procurement by JPUs and the prices they pay have impacted both overseas buyers and Japanese industrial users.

4-1. Thermal coal procurement by JPUs

Thermal coal procurement is affected by a JPU's power generation and coal consumption plans, coal procurement policy (i.e., securing a stable and economically efficient coal supply while diversifying supply sources, etc.), market conditions, the many supply options (producing countries, shipping ports, coal suppliers, etc.) and the percentage of term contracts (annual and multiple-year contracts) and spot contracts. Prior to the liberalization of electric power sales in Japan[28], JPUs

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[27] The Ministry of Foreign Affairs; Diplomatic Bluebook 1980 (written in Japanese)

https://www.mofa.go.jp/mofaj/gaiko/bluebook/1980/s55-2020501.htm/

[28] Wholesaling of electric power was liberalized in 1995. This caused independent power producers (IPPs) to enter the power generation business to supply electric power to JPUs. The process of liberalizing electric power retailing began in March 2000, enabling retail sales to large customers with contracted power of over 2,000kW (e.g., large factories, department stores and office buildings). This also caused power producers and suppliers (PPSs) to enter the electric power retail market. In April 2004 and April 2005, the liberalization of electric power retailing expanded to medium-sized customers with over 500kW and over 50kW in contracted power, respectively. In April 2016, the liberalization process was completed with its expansion to small customers with less than 50kW in contracted power.

Agency for Natural Resources and Energy (written in Japanese)

prioritized coal supply stability and purchased coal under term contracts, procuring very limited quantities through spot tenders[29].

4-2. Pricing of Australian thermal coal for JPUs

The prices paid by JPUs for Australian thermal coal had been determined by benchmark pricing since Japanese Fiscal Year (JFY) 1987. The champion negotiators for buyers and sellers were selected from among the various JPUs and Australian coal suppliers, respectively, and they then discussed a fixed price (benchmark) for each JFY. Once a benchmark for a year was agreed, the other JPUs and Australian suppliers accepted it as the contract price. J-Power assumed the role as the first champion negotiator for the JPUs and was followed by Chugoku Electric Power. Chubu Electric Power worked as the third champion negotiator between JFY1990 and 1997. When Chubu was the buyers' champion negotiator, the suppliers' champions were Shell (the supplier of Drayton coal), Ulan (Ulan coal) and MIM (Newlands coal)[30].

In the mid-1990s, TPC (Taiwan Power Company) and KEPCO (Korean Electric Power Corporation) increased their coal procurement through tenders, concluding spot or term contracts (the contract periods of TPC's term contracts were from one to seven years[31]) at bids lower than the benchmark. The JPUs responded by introducing tenders themselves. However, the JPUs contracted for limited quantities through tenders, instead purchasing higher quality coal (higher energy, lower sulphur, lower nitrogen, lower ash, etc.) than Taiwanese and Korean buyers mostly from the contract suppliers.

4-3. Changes in JPU coal procurement and pricing

The JPUs have changed their approaches to coal procurement and price negotiation in response to substantial changes in both the wider business environment and the thermal coal market (e.g., fierce competition resulting from the liberalization of electric power sales, abolition of the total cost system for retail pricing of electric power[32], expansion of the spot coal market, penetration of the spot thermal coal price index into the market[33] and increased coal price volatility.

The first major change was the end of the champion negotiator system, which left JPUs to negotiate with coal suppliers individually. However, Chubu Electric had served as the champion negotiator for many years, unintentionally bequeathing it a great deal of influence over the thermal coal market. This meant that the price to which Chubu agreed with Australian coal suppliers for each JFY was regarded as a "Reference Price" (RP) by other market participants in their own price negotiations. However, as it was no longer the benchmark, the prices contracted by other JPUs could differ slightly from the RP depending on the market situation and the contract conditions.

Chubu and Tohoku Electric Power negotiated the JFY2002 price with Australian suppliers separately and simultaneously. Negotiations were prolonged by very large differences in the prices the parties were seeking. The two JPUs finally agreed to different prices with suppliers[34]. Although the JFY2002 price negotiations became a catalyst for later individual price

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https://www.enecho.meti.go.jp/category/electricity_and_gas/electric/electricity_liberalization/what/

[29] In those days, each of JPUs purchased coal on a spot basis only when testing new coal resources for trial combustion at its power plant(s) or in the event of additional coal demand due to failures in its own non-coal-fired power plant(s) or another company's power plant(s).

[30] Agency for Natural Resources and Energy; Coal Notebook 1996, p.131. & Coal Notebook 1997, p. 127 (written in Japanese)

[31] Productivity Commission; op.cit., p. D14

[32] https://www.enecho.meti.go.jp/category/electricity_and_gas/electric/fee/structure/pricing/

[33] In 2001, eight coal consumers and suppliers including Anglo American, BHP, Glencore, Rio Tinto, J-Power, Enel and Uniper jointly established globalCOAL in London. globalCOAL provides an online coal transaction platform (https://www.globalcoal.com/) for its member companies and announces a spot coal price index. Currently, its price index for thermal coal shipped from Newcastle (globalCOAL NEWC) is the principal index for Australian thermal coal prices for Japan.

[34] In early May of 2002, Chubu Electric agreed with its Australian suppliers at $31.85 per MT FOB Australia. In mid-May, Tohoku Electric agreed with its Australian counterparts at around $28.75 per MT.
TEX Report; Coal Yearbook 2003, p. 6 (written in Japanese)

negotiations, it is believed that the RP system has continued up to the present with slight changes in style.

JPUs have been making a number of coal procurement efforts to ensure economic efficiency and supply stability in the rapidly changing business environment and thermal coal market. The following are some examples.

a)   Diversification of contract periods

   The general practice in JPU coal procurement for many years had been to follow the JFY calendar, with contracts commencing on the first day of April and expiring on the last day of March of the following year. In response to greater coal price volatility, JPUs began including contracts beginning in July, October and January in their portfolios. Although no quantitative analysis has been conducted, JPU coal procurement contracts commencing in April are still said to account for the largest percentage, followed by contracts commencing in October. For contracts commencing in April and October, the prices agreed by Tohoku Electric and the major Australian suppliers (usually, Glencore) have been regarded as the RPs by other participants in the market.

b)   Introduction of index-linked prices (floating prices)

   JPUs have been trying to increase their use of floating price contracts linked to spot price indices to mitigate the price volatility risks posed by fixed contract prices. Some JPUs conclude risk-hedging contracts with financial institutions that give them the option of fixing floating prices whenever they choose. They pay close attention to the movement of the price indices and exercise their options when they expect a price increase.

5.   Views on the use of coal

   Despite the growing headwinds facing the use of coal, global energy demand is increasing due to the growth of the world economy. The future of coal use should be determined in light of its economic efficiency, among its many other superior characteristics (e.g., abundant resources throughout the world, supply stability, etc.). If coal cannot sustain its competitive edge in light of the environmental costs in competition with other energy resources, it would be difficult to justify its continued use. On the other hand, the continued use of coal for power generation as well as steelmaking would contribute to the diversification of energy resources and reduce dependence on specific resources or technology. It is necessary to maintain the economic efficiency of coal use by decreasing its environmental costs through technological developments (e.g., eco-friendly use of coal, carbon capture, utilization and storage (CCUS)) in addition to reducing both coal production costs on the supply side and consumption costs on the demand side.

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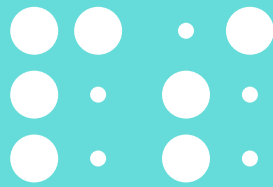
June 1988

10) Australian Coal Report; COAL 1995

11) Barlow Jonker Pty Ltd.; COAL 2005

12) TEX Report; Coal Yearbook 2010 to 2018 (written in Japanese)

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The Institute of Energy Economics, Japan