A Feasibility Study on the Supply Chain of CO2-Free Ammonia with CCS and EOR

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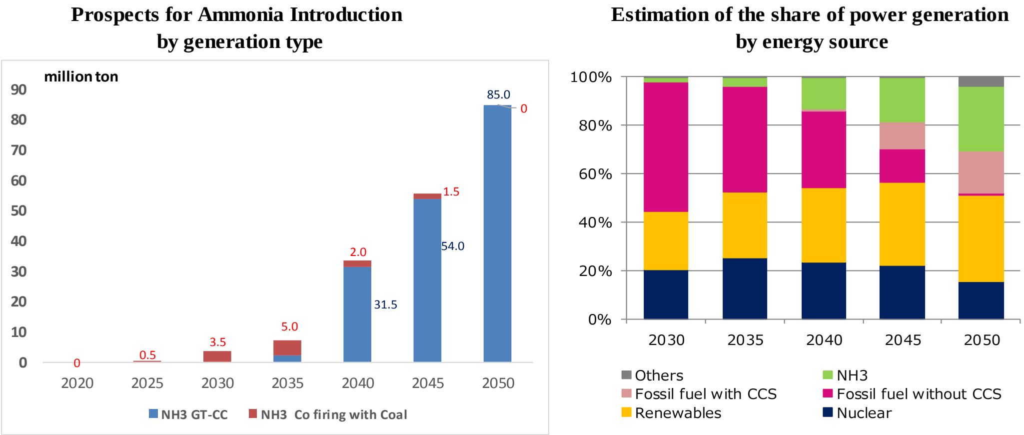
1. Background and Purpose

1.1. Background of This Research (Preliminary Study)

The Institute of Energy Economics Japan (IEEJ) conducted a study during 2016 and 2017 to figure out what was needed to achieve the Japan's goal of an 80% reduction of CO_2 emissions by 2050 (from the 2013 level) using an optimization model. The study showed that the power generation sector, which emits nearly a half of the total CO_2 emissions as shown in Figure 1.1-1, must achieve at least almost zero emissions in 2050 by means of some measures in order for Japan to keep the total industrial balance. According to the study, power generation with ammonia-fired gas turbine combined cycles (GT-CC) will play a major role along with renewable power generation and carbon capture & storage (CCS) after 2040. Even though with no detailed analysis, the study also showed that "coal co-firing" with CO_2-free ammonia would bring a certain effect (at least economically) on reduction of CO_2 emissions from coal-fired power generation around 2030 in which full switching from coal co-firing to ammonia gas turbine combustion would be still difficult to be achieved and the CO_2 emission reduction target will remain at a relatively moderate level. This result implies that the co-firing technology would open a way to effective use of high-efficiency large coal-fired thermal generation plants.

This work was supported by Council for Science, Technology and Innovation (CSTI), Cross-ministerial Strategic Innovation Promotion Program (SIP), "Energy Carriers" (Funding agency: JST).

Figure 1.1-1 Prospect for power generation and NH_3 introduction in Japan
(80% CO_2 reduction in 2050 from 2013 level)



(Note) "Restricted" case refers to a case in which the ammonia share in the generation mix is limited to 25% or lower.
(Source) Hirai, Kawakami; "Use of Ammonia As an Energy Source in Japan", IEEJ/HP, July 2017

1.2. Purpose of This Research and Analysis Approaches

Based on the preliminary study above, IEEJ decided to conduct this research for a full-scale quantitative analysis of how the Japanese power generation sector can introduce a technology of coal co-firing with CO_2-free ammonia imported from abroad around 2030 (from 2025 to 2035) in order to achieve carbon reduction. The research is intended to show the concrete feasible ammonia deployment level. Furthermore, IEEJ also sets up an action plan to implement the ammonia deployment and estimates the costs and funds necessary for the action plan as well as the cost for the Government of Japan to provide expected financial support (for refitting fuel supply facilities, expanding fuel receiving facilities and constructing ammonia tankers) and for fuel incentives (or CO_2 credits). The final purpose of the research is to do a business feasibility assessment (pre-FS) overlooking an entire supply chain of CO_2-free ammonia. The analysis approaches used for the purpose are summarized as follows:

(1) Quantitative analysis of ammonia input using power generation mix model (Chapter 2)

Using various analysis models including the power generation mix model owned by IEEJ, this research sets up an installed capacity for mixed combustion of each coal-fired thermal power plant and determines its operation pattern (base load operation) to estimate the monthly ammonia input.

(2) Analysis of logistics scheme (ship scheduling) (Chapter 3)

The research discusses an efficient and flexible logistics scheme (including export bases, tankers and import bases) and quantitatively analyses how the production and logistics (shipping) systems should keep balance with actual efficiency taken into account on the premise that ammonia supply from producers to power plants is implemented at a minimal cost. As described in the previous section (1), the research finally considers a consistent logistics scheme not only for coal co-firing but also for mainly gas turbine generation in the volume consumption age in the long view.

The research sets up a model plant of standard specifications shared among three overseas production sites (whose scope stretching from a point connected with a pipeline from a CCS/EOR site to an export terminal) and calculates the economic efficiency. The export price (FOB) is calculated on a cash flow basis (and Japan CIF price also estimated if necessary) to enable investors to make a proper decision.

(3) Economic assessment of CO2-free ammonia production plants (Chapter 4)

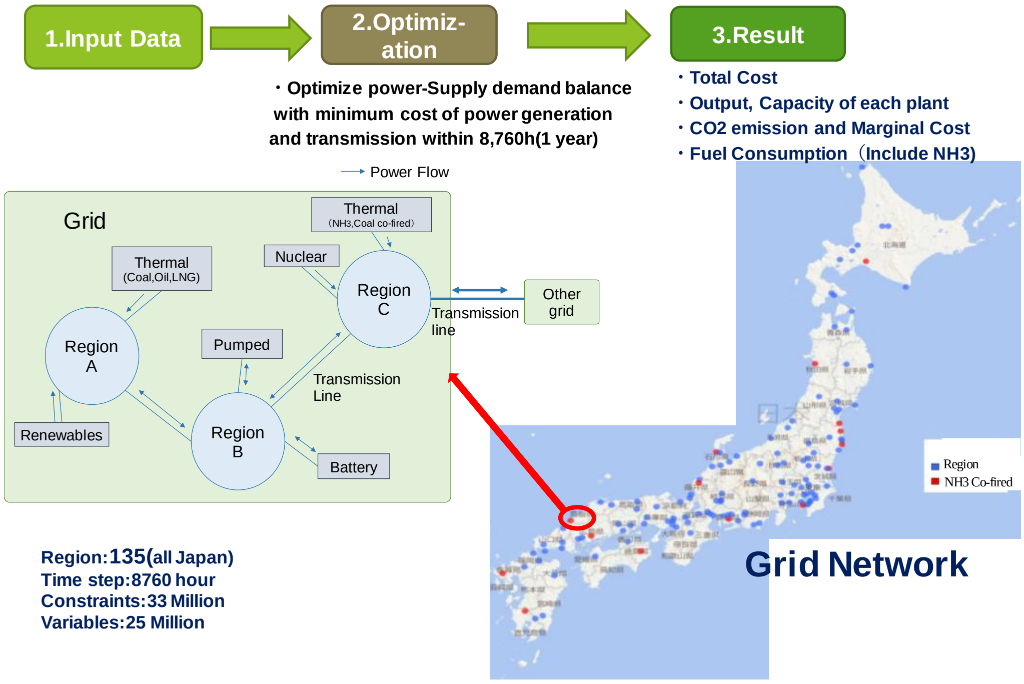
Among the production sites stated in (2) above, Saudi Arabia is the only country for which IEEJ made assumptions and economic calculation itself. For the other sites, IEEJ used the results of analyses provided by Mitsubishi Corporation and Marubeni Corporation and made estimation in cooperation with them as well. IEEJ compiles individual assessments of these three sites into a comprehensive assessment.

2. Deployment of CO_2-Free Ammonia in Domestic Power Plants

2.1. Power Generation Mix Model

The power generation mix model can represent nation-wide utility grids throughout Japan. It is a mathematical programming model for determining the optimal power generation mix and the optimal operation pattern throughout the year at minimal total costs that meet various constraints on power systems including supply-demand balance and load following capability of power plants.

Figure 2.1-1 Overview of IEEJ power generation mix model



The model is designed to allow the user to make settings for thermal, nuclear and other power generation plants, transmission lines and electricity storage facilities. When an electricity demand is given under these settings, the model will select through calculation a most economically reasonable combination of generation plants and their optimal operation pattern (time-series generation and transmission amounts). Changing the numerical settings and/or constraints will allow simulation of different power systems under various circumstances such as higher crude oil price, lower renewable energy cost or carbon price setting. This generation mix model can be used to determine on a trial basis the optimal energy mix under specific conditions or the grid modification and additional plant capacity as well as their related costs necessary for being compatible with renewable energy introduced. This estimation leads to comprehensive assessment of power generation cost not only for a single power plant but also for the total electricity system in the country.

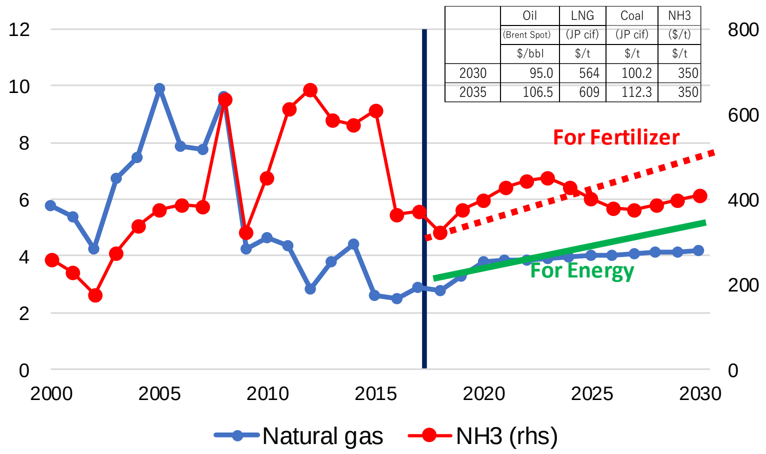
The generation mix model used in this research is based on the optimal generation mix model developed by Prof. Yasumasa FUJII and Assoc. Prof. Ryoichi KOMIYAMA, both from the University of Tokyo. The model shows power demand variations and solar photovoltaic/wind generation output variations throughout Japan at a one-minute resolution for a year (365 days). Japan is divided into nine areas, from which 135 locations are simulated as nodes. Each node represents a region with local generation plants and substations. This model uses linear programming (LP) for optimization to minimize the annual total electricity system cost of all utility power system in Japan, determining the optimal plant operation.

2.2. Assumptions

2.2.1. Energy Prices

The energy prices in 2030 and 2035 are assumed as shown in Figure 2.2-1. The price of ammonia as an energy source is set at about 70 percent of the price of ammonia as chemical fertilizer and is assumed to be same in both 2030 and 2035. (For relative comparison to other types of energy, the ammonia price is assumed to decline in the period between 2030 and 2035, roughly from \$350/MT to \$315/MT).

Figure 2.2-1 Energy price setting



	Oil	LNG	Coal	NH3
	(Brent Spot)	(JP cif)	(JP cif)	(\$/t)
	\$/bbl	\$/t	\$/t	\$/t
2030	95.0	564	100.2	350
2035	106.5	609	112.3	350

(Source) Natural gas: Henry Hub; NH_3 (for chemical fertilizer): Asia CIF, Fertecon; NH_3 (for energy): IEEJ estimate
Coal, Crude oil, LNG: IEEJ Outlook 2018

2.2.2. CO_2 Reduction Scenarios

As shown in Table 2.2-1, CO_2 emission reduction scenarios are assumed based on "the Long-term Energy Supply and Demand Outlook" by the Agency of Natural Resources and Energy.

Table 2.2-1 CO_2 emission reduction scenarios of power generation sector

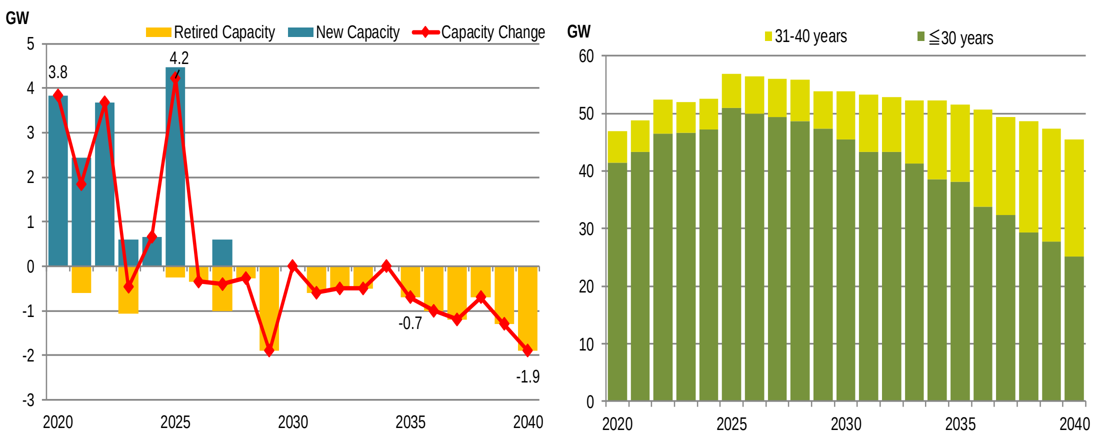
	2013	2030	2035
Emission from Utility Power [Mt]	**484**	**299**	**254**
Reduction from 2013	**-**	**-38.2%**	**-47.5%**
Power Demand[TWh]	844	847	843
Emission factor[kg/kWh]	0.57	0.35	0.30
Emission from Whole Power Sector[Mt]	548	360	314
Reduction from 2013	-	-34.3%	-42.7%

2.2.3. Capacity of Coal-Fired and Coal-Ammonia Co-Firing Power Plants

(1) Assumptions on installed capacity

As shown in Figure 2.2-2, the current capacity assumption of coal-fired thermal power plants will remain until around 2025 and, after that, the capacity (stock) will decline as almost no new plants will be built while more and more existing plants will be closed.

Figure 2.2-2 Future increase/decrease in installed capacity of coal-fired power plants (new/closed plants)



The ammonia-coal co-firing technology will be mainly introduced into existing thermal power plants. We have selected candidate plants according to three criteria. The first is that the plant must have an overall generation capacity of not less than one million kW and each of its generation units must have a capacity of not less than 0.5 million kW (high thermal efficiency with the most advanced technology). The second is that the plant has been operated for not more than 40 years (if possible, not more than 30 years). The third is that the plant has a fuel receiving facility, i.e., a large ship berth is available (for high transportation efficiency). Table 2.2-2 lists the selected thermal power plants.

For transportation of ammonia from source countries to domestic power plants, supertankers (VLGCs of 50-thousand-MT class) will be used for delivery to three domestic hub ports (import bases A, B and C), from which domestic vessels (10-thousand-MT class) will transfer ammonia to power plants. This is the most efficient transportation system. However, it may be quite difficult in terms of time to implement the system nationwide quickly by 2030. Then, we assume that only one of the three hub ports will be used to deploy the system mainly for the Kanto and Chubu Region. For the other regions, several plants to which ammonia can be delivered from a port nearby capable of accepting an MGC class ship (30-thousand-MT class) directly coming from an oil-producing country will introduce the system. We assume that the system will be deployed nationwide in 2035 (for more information, see Chapter 3).

Table 2.2-2 Coal-fired power plants introducing ammonia co-firing

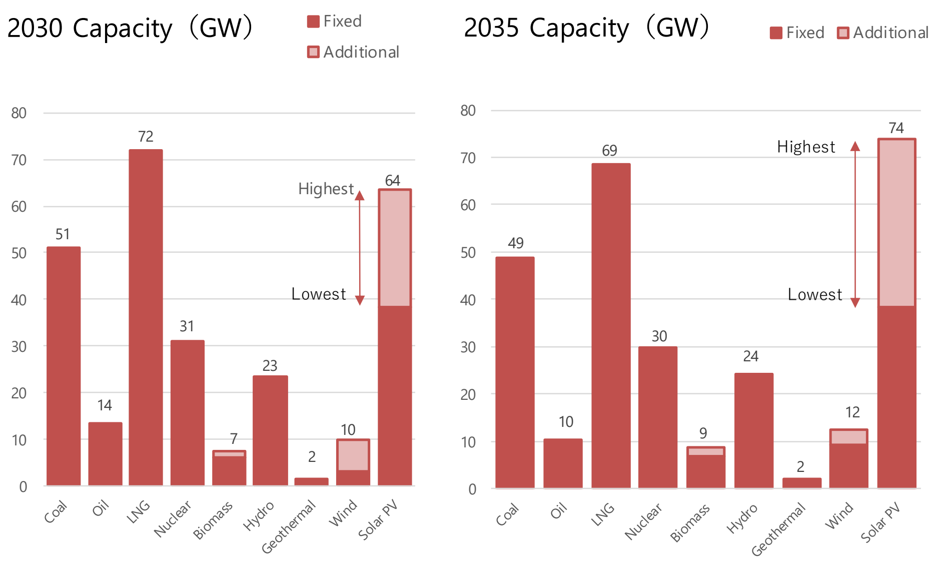
	Power Plant	Capacity (GW)	Capacity of NH_3 Co-fired (GW)		
			2025	2030	2035
Hokkaido	A-1	0.7	0.7	0.7	0.7
Tohoku	A-2	0.6			0.6
		0.6			0.6
	B-1	1		1	1
Tokyo	B-2	0.6			0.6
		0.6		0.6	0.6
	B-3	1		1	1
	B-4	0.65		0.65	0.65
		0.65			0.65
	B-5	1		1	1
	B-6	1		1	1
Chubu	B-7	1			1
		1	1	1	1
Hokuriku	A-3	0.5			0.5
	A-4	0.5			0.5
Chugoku	C-1	1		1	1
	C-2	0.6	0.6	0.6	0.6
Shikoku	C-3	1.05			1.05
Kyushu	C-4	0.7			0.7
	C-5	1			1
	C-6	1			1
Total	**17 Plants,21Units**	**16.8**	**2.3**	**8.6**	**16.8**

(Note) The ammonia mixing ratio in coal is assumed to be fixed at 20% (in calorific value). A study with an aim of achieving 50% co-firing (by improving combustibility, effluent composition and thermal efficiency) has already been launched.

2.2.4. Installed Capacity of Power Generation Plants by Energy

Figure 2.2-3 shows assumed installed capacity for electricity generation by energy in 2030 and 2035. Each bar shows assumed maximum possible capacity for wind, solar PV and biomass or assumed installed capacity in 2030 and 2035 for the other power generation.

Figure 2.2-3　Assumed installed capacity for power generation by energy (2030,2035)



(Source)　Installed capacities of thermal, hydro and geothermal plants are assumed based on the utilities' electric supply plan, and those of biomass, wind and solar PVs assumed based on the FIT approved capacity 2017 for minimum level and based on "the Long-term Energy Supply and Demand Outlook" for 2030 for maximum level.

Assumptions on installed capacity of renewable power generation plants are based on the capacity projection for 2030 indicated in "the Long-term Energy Supply and Demand Outlook" issued in 2015. For regional distribution, the capacities for wind, solar PV and geothermal generation are distributed according to the FIT (Feed-in Tariff) approved capacity of each region and those of hydro generation distributed by taking into account any plant construction/closing schedules included in the utilities' electric supply plan. Any additional capacity is distributed according to potential hydro-energy in each region.

The installed capacity for thermal power generation is assumed by taking into account any plant construction/closing schedule with a high probability at this moment including those that have been listed on the utility's electric supply plan or applied for grid connection, in addition to existing plants.

2.2.5. Other Cost Factors

The power generation equipment cost shown in Table 2.2-3 is derived from the cost estimation for 2030 presented by the Power Generation Cost Verification Working Group. Note that the analysis using the generation mix model in this research aims to estimate the accurate cost and benefit to the whole country. Even for generation technologies using renewable energy to which the FIT mechanism is applied, the cost calculation is based on actual costs (on the precondition that FIT is not applicable).

For coal-fired thermal generation, the cost shown in Table 2.2-3 does not include the costs required to reinforce piers, install fuel piping & tanks and install/retrofit fuel supply equipment (including combustion burners) for implementing ammonia-coal co-firing technology. (These additional required costs have been calculated and input to the cost data for the generation mix model).

The generation mix model is designed to simulate, in response to electric power fluctuation attributable to renewable energy within each grid, thermal power generation output adjustment, electricity interchange among grids (use of main distribution lines), pumped storage generation, accumulator batteries, and adjustment of output to renewable power (output control commands from the central power supply control room and other hardware responses). The cost related to the output control equipment for renewable power generation is added to the equipment cost for renewable power generation.

Table 2.2-3 Equipment cost by energy

		Coal	LNG	Oil	Nuclear	Biomass	Hydro	Geo-thermal	Solar Solar farms	Solar Household	Wind
Capital Cost	10,000 Yen/kW	25	12	20	37	39.8	64	79	22.2	25.8	25.2
Power Cost	Yen/kWh	8.9	11.6	25.7	8.8	28.1	10.8	10.9	12.9	15.3	13.8
Capacity factor	%	70%	70%	30%	70%	87%	45%	83%	14%	12%	20%

(Source) The Power Generation Cost Verification Working Group (Estimate for 2030)

(Note) Fuel costs of coal, oil and LNG follow Figure 2.2-1

2.3. Analysis Method

Reference cases for 2030 and 2035 are called Base 1 and Base 2 respectively. Both cases are based on an assumption that generation plants will be operated at a fixed capacity equivalent to the installed maximum capacity (stock) for each energy type shown in Figure 2.2-3 without ammonia-coal co-firing and the installed capacity will be fully achieved. The overall power generation sector is assumed to achieve a 38.2% CO_2 emission reduction from the 2013 level (equivalent to “the projection of the Long-term Energy Supply and Demand Outlook”) for the Base 1 case and a 47.5% reduction from 2013 for the Base 2 case as shown in Table 2.2-1. Next, another set of cases with ammonia-coal co-firing are called N1-B for 2030 and N2-JP for 2035. For both cases, assumptions are made so that the investment on new equipment to generate electricity from highly fluctuating solar PV/wind energy and on those for biomass power generation that is dependent on overseas resources can be suppressed for economic efficiency (optimization) upon ammonia deployment. Table 2.3-1 summarizes these cases for comparison between the reference cases and the ammonia-coal co-firing cases for 2030 and 2035.

Table 2.3-1 Analysis cases

Year	Case	Power Generation Mix	Renewables Investment	CO_2 Target (Utility Power)	NH_3,Coal co-fired	NH_3 transportation
2030	**Base1**	"Long-term Energy Supply and Demand Outlook" (Nuclear 21%,Renewable 23%,Thermal 56%)	Same as "Long-term Energy Supply and Demand Outlook"	299Mt (38% reduction from 2013)	No	-
	N1-B	Cost minimization under some conditions	Highest:same as above. Lowest:FIT Approved (2017)		20%-NH3	1 NH3-hub port, Regional transportation
2035	**Base2**	IEEJ Assumption from"Long-term Energy Supply and Demand Outlook" (Nuclear 21%,Renewable 29%,Thermal 50%)	As much as necessary for the generation mix	254Mt (48% reduction from 2013)	No	-
	N2-JP	Cost minimization under some conditions	Highest:same as above. Lowest:FIT Approved (2017)		20%-NH3	3 NH3-hub ports, Nation-wide transportation

2.4. Analysis Results (Optimization using Power Generation Mix Model)

Based on the assumptions and analysis cases, the power generation mix is optimized using the model. The calculation results are summarized in the following:

2.4.1. Thermal Power Plant Operation and Ammonia Input

Table 2.4-1 summarizes the results of the optimization calculation. According to the table, co-firing generation plants will consume about 3.5 million MTs (more accurately 3.46 million MTs) of ammonia in 2030 and about 5 million MTs (more accurately about 4.87 million MTs) in 2035.

Table 2.4-1　Thermal power generation analysis results

		2030		2035	
		Base1	N1-B	Base2	N2-JP
Capacity [GW]	Coal	51	43	49	32
	NH3/Coal Co-fired	-	8	-	17
	LNG	72	72	69	69
Fuel Consu-mption [Mt]	Coal	109	106	95	74
	NH3	-	3.5	-	4.9
	LNG	13	22	15	32
Genera-tion [TWh]	Coal	302	293	263	207
	NH3[1]	-	8	-	12
	LNG	107	183	120	260
Fuel Cost [Billon Yen/year]		2,249	2,975	2,182	3,290
Additional Investment[2] [Billon Yen]		-	188	-	402

(Note 1)　Refers to an amount of electricity generated by ammonia-coal co-firing thermal power plants. The generation of co-firing power plants is divided into coal and ammonia portions according to their own calorific value.

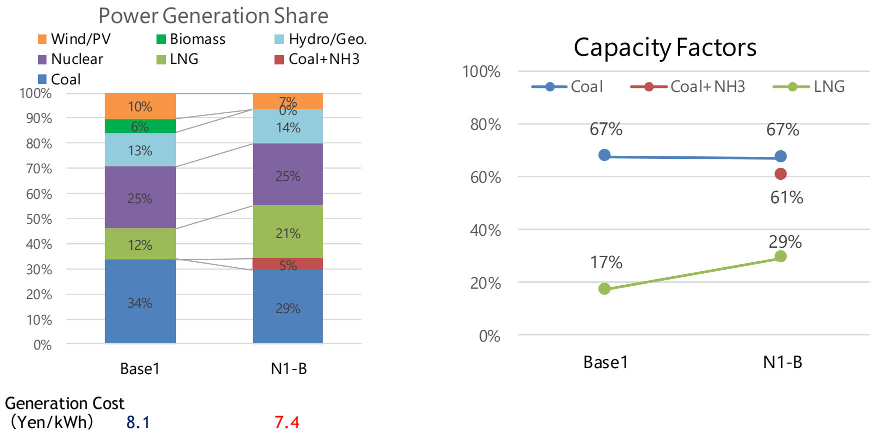
(Note 2)　The cost of additional equipment for NH_3-coal co-firing generation includes partial reinforcement of berths, installation of tanks and pipelines, and retrofitting of fuel/combustion equipment.

2.4.2. Variations in Power Generation Mix and Plant Capacity Factor

(1) Simulation for 2030 (Base 1 and N1-B cases)

As shown in Figure 2.4-1, as ammonia-coal co-firing generation increases, investment (for higher installed capacity) on renewable energy (biomass, solar PV and wind) plants would be suppressed to curve the generation. On the other hand, the liquid natural gas (LNG) fired generation will increase. This result implies that, while the costly renewable power generation would attract less investment in spite of zero CO_2 emissions, alternative ammonia-coal co-firing technology and LNG that generally meets the CO_2 emissions constraints and costs relatively low are an optimal option.

Figure 2.4-1 Variations in generation mix and plant capacity factor (2030)



(Note 1) Left: Total generation is 880 TWh and CO_2 marginal abatement cost is around \$50/MT.

(Note 2) Right: Biomass (Base 1: 77%, N1-B: 0%)

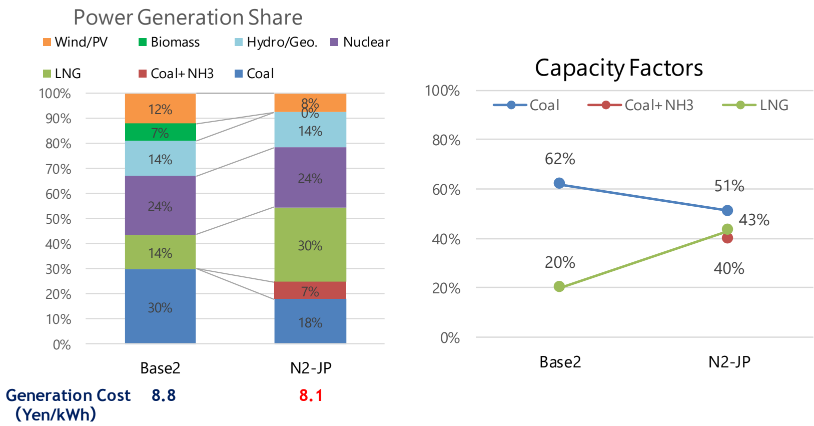
Solar PV, Wind, Hydro, Geothermal and Nuclear show a same capacity factor for the both cases.

(2) Simulation for 2035 (Base 2 and N2-JP cases)

As shown in Figure 2.4-2, as ammonia-coal co-firing generation increases, investment (for higher installed capacity) on renewable energy (biomass, solar PV and wind) plants would be suppressed to curve the generation. On the other hand, the LNG-fired generation will increase. This trend is similar to the 2030 cases discussed in item (1).

However, since the CO_2 emissions target will be even stricter in 2035 (the 38.2% reduction in 2030 from the 2013 level will be raised to a 47.5% reduction in 2035), LNG-fired power generation will be even more popular in 2035. Coal-fired generation, whose capacity factor of 67% mostly remains in 2030, will eventually drop from 62% to 51% in 2035. Solar PV, wind and biomass power generation technologies, which are highly variable energy sources, will show the similar trend as that in 2030, according to the calculation.

Figure 2.4-2 Variations in generation mix and plant capacity factor (2035)



(Note 1) Left: Total generation is 880 TWh and CO_2 marginal abatement cost is around $70/MT.

(Note 2) Right: Biomass (Base 2: 77%, N2-JP: 0%), Solar PV (Base 2: 12%, N2-JP: 13%)

Wind, Hydro, Geothermal and Nuclear show a same capacity factor for the both cases each.

3. Analysis of Logistics System (Ship Scheduling)

3.1. Logistics System

3.1.1. Transportation Cost Minimization and Ship Scheduling

The number of CO_2-free ammonia producers is probably increasing in the Middle East, Australia, the U.S. and other areas in the world as the demand increases. It is also projected that domestic power plants expected to introduce the ammonia will expand throughout Japan. Therefore, it is not necessarily appropriate to discuss the ammonia transportation cost only for a single marine transportation route between overseas producers and domestic consumers in developing a concrete business model. Using large-sized tankers to deliver in one go to power stations may be economically preferred, but many power stations do not actually have a facility that allows such large ships to anchor. Relatively small-sized tankers, on the other hand, could be accepted by existing facilities of power stations, but would incur a high transportation cost. In addition, for long duration ocean transportation, the latter shipping involves lower tanker turnover and lower transportation efficiency, resulting in lower economic efficiency particularly when the shipbuilding cost is taken into account.

Therefore, to minimize the maritime transportation system cost, it is essential to ensure appropriate ship scheduling according to the production (including production pattern) of producing regions and the demand (including demand pattern) of power plants. In terms of tankers, it is important to implement ship scheduling with a minimum number of tankers of an appropriate size for a maximum turnover.

This research has developed a new ship scheduling model using mixed integer programming (MIP), which is a combination of linear programming and integer programming, to perform optimization simulation. For optimization of the logistics system to be used in ship scheduling, we assume that ammonia produced in overseas countries will be transported by large ocean tankers to an appropriate number of selected domestic hub ports (import terminals), instead of direct transportation to power plants. From the import terminals, relatively small tankers will be used to transfer to individual power plants.

According to the simulation, as the number of producers and consumers increases, the total cost can be further reduced by optimizing the ship schedule although the import terminal cost will be higher. As described in Chapter 1, if ammonia fuel is used not only for ammonia-coal co-firing but also for gas turbine combined cycle in future, it will be possible to upsize the ocean tankers from VLGC to even larger ships. This means that the hub port system would be preferred. In the initial phase of ammonia deployment, however, consuming power plants would be geographically concentrated in a specific area in Japan and would only consume a low amount of ammonia. Therefore, it would be desirable to apply the hub port system to the plant intensive area and the direct transportation system to the other areas

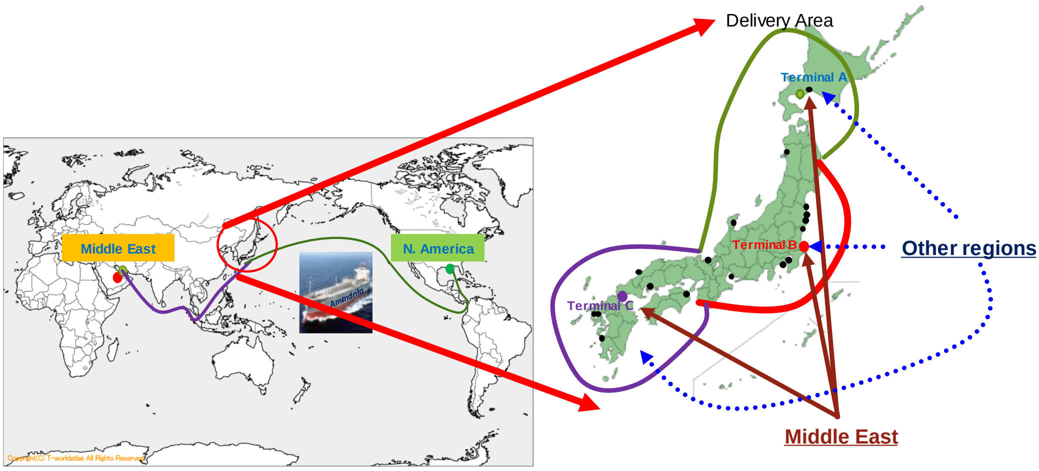
3.1.2. Transportation Cost Minimization and Ship Scheduling

(1) Logistics model in this research

As shown in Figure 3.1-1, the domestic distribution network is divided into three zones, Areas A, B and C, with liquid petroleum gas (LPG) transportation in mind. The Area A covers Hokkaido, Northern Tohoku and areas along the Japan Sea coastline (from Aomori to Fukui) with a central import terminal located in Hokkaido. The Area B covers Southern Tohoku, Kanto and Tokai regions with a central import terminal located on the Pacific Ocean coast in the Kanto Region. The Area C covers Kyushu, Shikoku, Setouchi (the Inland Sea area) and Sanin with a central import terminal located in the Northern Kyushu or in the west end of the Chugoku Region.

As overseas producing sites, three locations are selected: Saudi Arabia, gas producing countries in the Arab Gulf, and North America (on the Gulf Coast).

Figure 3.1-1 Outline of logistics model in this research



(2) Ship scheduling in this research

The cargo transported from the overseas producing sites to the domestic import terminals is distributed according to an optimal ship schedule based on the annual demand of domestic distribution areas and the reservoir capacity of import terminals. In each distribution area, tankers are operated according to an optimal ship schedule based on the monthly demand and reservoir capacity of local power plants to satisfy the demand. The 2035 simulation uses the three import terminal distribution system while the 2030 simulation only uses the import terminal in the Area B. The other Areas where only a couple of power plants are located use direct transportation from producing countries, not the hub port system.

Two-port unloading and demurrage upon double pier docking (due to natural condition) are assumed to occur at an estimated average annual rate (based on general records) to figure out the additional incurred cost as a whole (from the macroscopic view). However, this research does not discuss this issue from the microscopic view, so called the "scheduling issue" of individual tankers.

3.2. Ship Scheduling for 2030

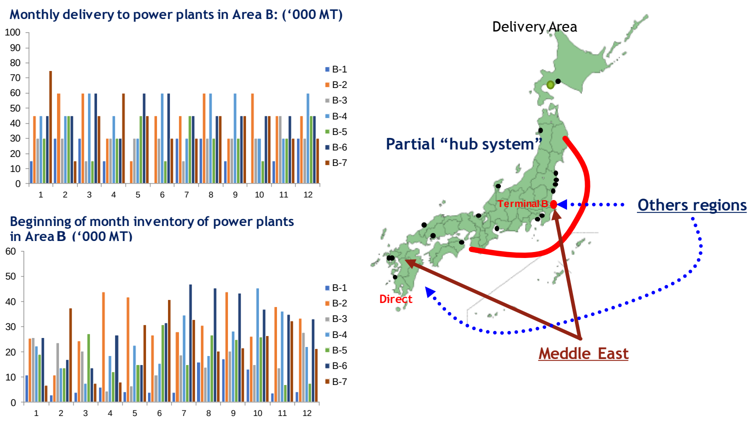
According to the calculation, the total ammonia demand of domestic power plants will be about 3.5 million MTs as shown in Figure 3.2-1. Ship scheduling meeting the demand can be implemented by a fleet of eight ocean tankers and three domestic tankers. The shipping cost (total logistics cost for direct distribution to power plants) will be $65.7/MT in terms of shipbuilding cost.

Figure 3.2-1 Overview of ship scheduling for 2030

Number of vessels	8	Total Investment	60 bill.JPY	Annual cost	14,101	(mill.JPY/yr.)
(of which) VLGC	7			Fixed cost	8,958	(mill.JPY/yr.)
(of which) MGC	1			Variable cost	5,143	(mill.JPY/yr.)
				Ave. shipping cost	4,541	(JPY/MT/yr.) $41.3/MT/yr.

NH_3 Production (1,000t)		Ocean Tanker (Vessel)		Coastal Tanker			Coal fired Power Station with blending NH_3		Ocean Tanker Transportation Cost ($/t)	Direct Transportation Cost ($/t)	Terminal Cost ($/t)	Coastal Tanker Transportation Cost ($/t)	Average of Logistics Cost ($/t)
					Size (t)	Vessel	Number	NH_3 Demand (1,000t)					
				A Area	15,000	0							
					10,000	0							
Arab Gulf	3,330	VLGC	7		Total	0	0	0					
				B Area	15,000	3				MGC			
The others	230	MGC	1		10,000	0				3 Vessels			
					Total	3	7	3,041		(to C Area)			
				C Area	15,000	0							
					10,000	0							
					Total	0	2	420					
Total	3,560	Total	8	All Japan		3	9	3,461	41.3	5.0	10	9.4	65.7

Number of vessels	3	Total inves	14 bill.JPY	Annual cost	3,185	mill.JPY/yr.
(of which)15k MT	3			Fixed cost	2,214	mill.JPY/yr.
(of which)10k MT	0			Variable cost	971	mill.JPY/yr.
				Ave. shipping cost	1,031	JPY/MT/yr. $9.4/MT/yr.



3.3. Ship Scheduling for 2035

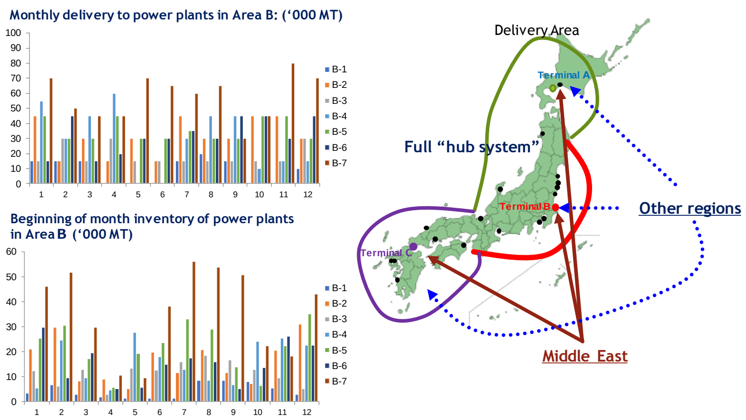
According to the calculation, the total ammonia demand of domestic power plants will be about 5 million MTs as shown in Figure 3.3-1. Ship scheduling meeting the demand can be implemented by a fleet of 12 ocean tankers and seven domestic tankers. The shipping cost (total logistics cost for direct distribution to power plants) will be \$62.9/MT in terms of shipbuilding cost.

Figure 3.3-1 Overview of ship scheduling for 2035

Number of vessels	12	Total Investment	90 bill.JPY	Annual cost	22,287 (mill.JPY/yr.)
(of which) VLGC	11			Fixed cost	13,578 (mill.JPY/yr.)
(of which) MGC	1			Variable cost	8,710 (mill.JPY/yr.)
				Ave. shipping cost	4,440 (JPY/MT/yr.) \$40.4/MT/yr.

NH_3 Production (1,000t)		Ocean Tanker (Vessel)		Coastal Tanker	Size (t)	Vessel	Coal fired Power Station with blending NH_3: Number	NH_3 Demand (1,000t)	Ocean Tanker Transportation Cost (\$/t)	Terminal Cost (\$/t)	Coastal Tanker Transportation Cost (\$/t)	Average of Logistics Cost (\$/t)
				A Area	15,000	1						
					10,000	1						
Arab Gulf	4,895	VLGC	11		Total	2	4	677				
				B Area	15,000	2						
The others	125	MGC	1		10,000	1						
					Total	3	7	2,545				
				C Area	15,000	2						
					10,000	0						
					Total	2	6	1,652				
Total	5,020	Total	12	All Japan		7	17	4,874	40.4	10	12.5	62.9

Number of vessels	7	Total inves	32 bill.JPY	Annual cost	6,846 mill.JPY/yr.
(of which)15k MT	5			Fixed cost	5,125 mill.JPY/yr.
(of which)10k MT	2			Variable cost	1,720 mill.JPY/yr.
				Ave. shipping cost	1,376 JPY/MT/yr. \$12.5/MT/yr.



3.4. Summary of Ship Scheduling

The major results of ship scheduling simulation for 2030 and 2035 are summarized in Table 3.4-1:

Table 3.4-1 Major results of ship scheduling simulation (2030 and 2035)

Year	NH_3 Demand (mill.MT)	Production (mill.MT)	Ocean-going Vessel (Hub shipping)	Coasting Vessel (Hub shipping)		Direct shipping	Total Investment	Shipping cost
2030 (N1-B)	3.46 A: 0 B: 3.04 C: 0.42	3.56 SAU 1.35 Other ME 1.99 N.America 0.23	Total 8 vessels VLGC 7 vessels MGC 1 vessel	Japan	Total 3 vessels 15k MT 3 vessels 10k MT -	3 vessels (MGC, C area)	$0.82 bill.	$65.7/MT
				A	Total -			
				B	Total 3 vessels 15k MT 3 vessels 10k MT -			
				C	-			
2035 (N2-JP)	4.87 A: 0.68 B: 2.54 C: 1.65	5.02 SAU 2.97 Other ME 1.93 N.America 0.13	Total 12 vessels VLGC 11 vessels MGC 1 vessel	Japan	Total 7 vessels 15k MT 5 vessels 10k MT 2 vessels	-	$1.11 bill.	$62.9/MT
				A	Total 2 vessels 15k MT 1 vessel 10k MT 1 vessel			
				B	Total 3 vessels 15k MT 2 vessels 10k MT 1 vessel			
				C	Total 2 vessels 15k MT 2 vessels 10k MT -			

(Note) Major assumptions

Ship cost: VLGC (55 thousand MTs) $70 million, MGC (25 thousand MTs) $52 million, 15 thousand MTs $42 million, 10 thousand MTs $40 million

Fuel price: (2030) GO $882/MT, FO $611/MT, (2035) GO $975/MT, FO $675/MT

Service speed: 16 knots

4. Supply Price of CO_2-free Ammonia

4.1. Analysis Approach

Discounted cash flow (DCF) analysis is used to estimate the ammonia shipping price (FOB) that meets a profitability target as well as the CIF price that is a sum of the FOB price, insurance and freight. As a general rule, profitability targets should be based on Equity Internal Rate of Return (EIRR). When a profitability target is set to 10% for instance, the price at which 10% profitability can be obtained is the minimum profitable price. For analysis of the ammonia price with financing feasibility taken into account, analysis with Project IRR (PIRR) is also conducted.

Table 4.1-1 shows the definition of these two IRRs:

Table 4.1-1 Definition of IRRs

EIRR (Equity IRR)	Profitability index of a project from investors point of view. IRR determined using the net cash flow from FCFE.
PIRR (Project IRR)	Profitability index of an overall project. IRR determined using the net cash flow from FCFF.

4.2. Assumptions

The general assumptions including plant capacity shown in Table 4.2-1 are provided so that all the three locations have uniform assumptions as far as possible. However, plant capital expenditure (CAPEX), CO_2 storage system (Carbon dioxide Capture and Storage or Enhanced Oil Recovery), tax depreciation and corporate tax rate are assumed individually according to regional circumstances as shown in Table 4.2-2. The case that meets the assumptions shown in Tables 4.2-1 and 4.2-2 are called "reference case".

Table 4.2-1 General assumptions

NH_3 production capacity	1.1 million MTPA (3300 MTPD, 8000 hours per year)
Recovered CO_2	2.1 million MTPA
Period for EPC / operation	4 years / 20 years
Terminal value	net-CF at final year / discount factor
Borrowing conditions	D:E=60/40, Tenor: 20 years, Interest: 5%
Natural gas price	$3/MMBtu

Table 4.2-2 Specific assumptions

	SA	Other ME	N. America
CO_2 decarbonization (Selling price[$/MT])	EOR 0	CCS (negative)	EOR 20
Target EIRR	10%	10%	7%
Depreciation Method	declining balance with 25%	15-year straight line	15-year straight line
Income tax rate	20%	35%	25%
Seaborne transportation	carried by VLGC		

(Note) EOR involves CO2 sales on pipeline (Saudi Arabia and North America). CCS does include storage (other Middle East countries).

(1) CO_2 sequestration and capture

A case of total 95% CO_2 capture, which is a combination of 100% capture of CO_2 emissions from the reforming process and 90% capture of CO_2 contained in utility's effluent gas, is called "full capture" and is used as a common reference case for the three locations. Another case of 100% capture of CO_2 emissions from the reforming process only (hereinafter referred to as "partial capture") is also used in trial calculation as a sensitivity analysis.
The CO_2 emissions per unit for full capture is 1.9 t- CO_2/t-NH3 and those for partial capture is 1.2 t- CO_2/t-NH3. Partial capture leads to lower CAPEX, lower natural gas input and lower consumption of industrial water. For Saudi Arabia, partial capture results in 14% lower CAPEX, 5% lower natural gas input, and 17% lower industrial water consumption (than full capture each).

(2) Transportation cost

A principal objective here is to compare profitability (FOB or CIF price) of plants installed in each production site. Then the cost of transportation along the single route between a production site and Japan (around Tokyo Bay), not the transportation system described in Chapter 3, is used. Tanker freight is set based on the (current) spot charter rate for VLGCs (LPG).

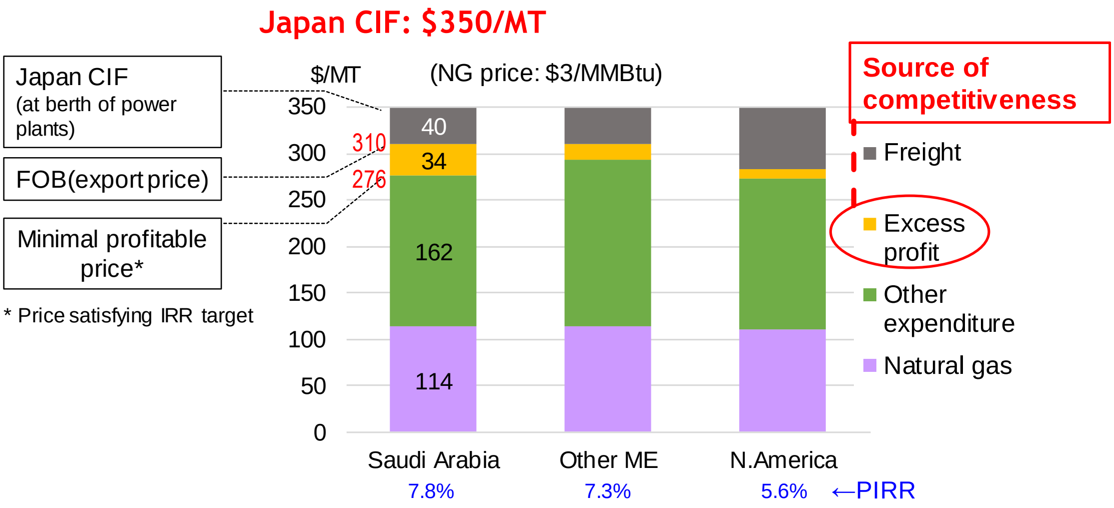
4.3. Trial Calculation with EIRR

4.3.1. Ammonia Shipping Price Based on EIRR Assessment

On the assumptions stated in the previous section, this section calculates profitability of ammonia production plants. The EIRR, which is one of the assumptions to assess plant profitability in the three regions, has been set to 10% for the Middle East and 7% for North America as shown in Figure 4.2-2. The minimum FOB price that can satisfy these

EIRR settings (hereinafter referred to as the "profitable export price") is calculated. As a result, the profitable export price for Saudi Arabia is $276/MT (natural gas $114/MT + other costs $162/MT) (Figure 4.3-1).

Figure 4.3-1　EIRR-Based Profitability Assessment (Market Price: $350/MT)



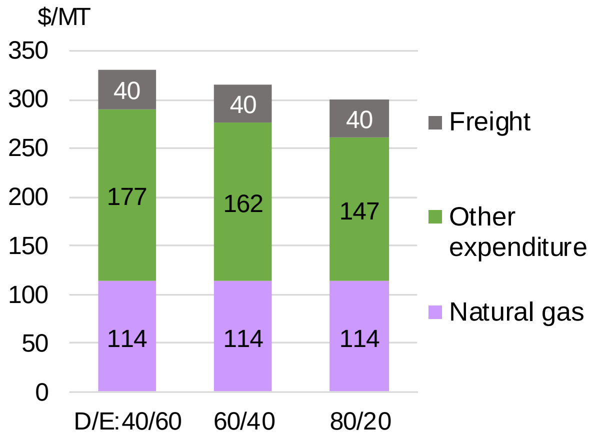
(Note)　Natural gas price: $3/MMBtu; Percentage shown below each place name in the figure above indicates PIRR based on which the "profitable export price" calculated from EIRR can be obtained.

On the other hand, when the market price of ammonia, namely, the Japan CIF price (a same price in a same market) is assumed to be $350/MT, freight can be subtracted from the price to obtain a so-called shipping price (FOB). For Saudi Arabia, subtract the freight $40/MT from $350/MT and get $310/MT. This is the FOB price. This FOB price is higher than the profitable export price by a difference of +$34/MT. This is an excess profit. Therefore, Saudi Arabia can compete in export with other producers with this excess profit. A positive excess profit means that the country has a certain capital for price competition while a negative excess profit means that the country is less competitive in the market. (Still, a negative excess profit does not mean putting it into the red right away because a certain profit within the range of 10% EIRR is secured).

4.3.2. EIRR Leverage Effect and PIRR Assessment Concept

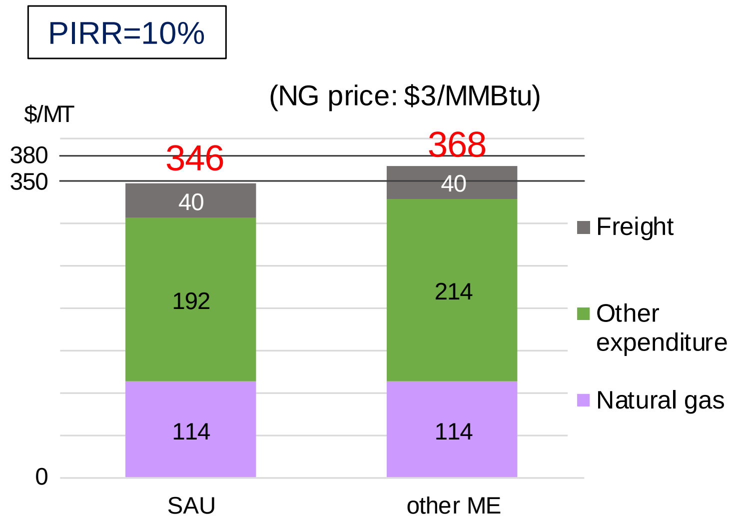
If project economy is assessed with EIRR, the business profitability is raised by the leverage effect as shown in Figure 4.3-2. This means that the profitable export price is lower. When viewed from an investor's point of view, this certainly brings a higher return to investors. In reality, however, the higher profitability is not achieved through improvement of the actual technical performance of the plant. The debtor who borrows the project capital should carefully assess the whole project economy apart from apparent profitability (from the view point of securing the principal for repayment).

Figure 4.3-2 D/E sensitivity analysis in EIRR assessment



Then, instead of EIRR, 10% PIRR is applied to Saudi Arabia and other Middle East region cases under the same assumptions as those for the reference case for the previous trial calculation in Figure 4.3-1. The result of the calculation is shown in Figure 4.3-3. The excess profit is only +$4/MT for Saudi Arabia and -$18/MT for other Middle East countries, not included in the figure though. Therefore, it would be difficult to keep the Japanese market price in equilibrium at $350/MT in this situation. An idea that an appropriate price may be higher than $350/MT by around $20/MT could be valid. EIRR and PIRR have their own merits and demerits since whether EIRR or PIRR should be selected also depends on the project financing style, the general project purpose and the project risk assessment. This research is originally intended to analyse the CO_2-free ammonia business feasibility from the viewpoint of realizing a supply chain of CO_2-free ammonia and developing markets. Remembering the importance of appealing to investors, we have decided to select EIRR while accepting its limit.

Figure 4.3-3 PIRR-Based Profitability Assessment

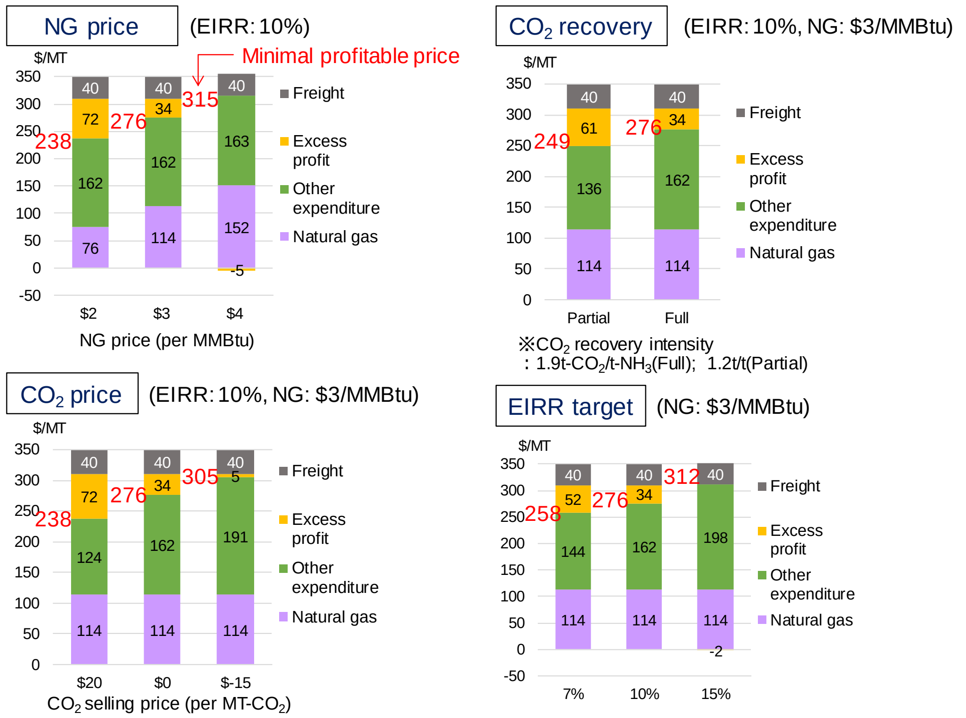


4.4. Sensitivity Analysis

This section applies sensitive analyses to the Saudi Arabia case by changing the settings of several parameters that may affect the ammonia shipping price. Specifically, natural gas price, CO_2 capture rate, CO_2 sales price and EIRR are shifted to see how the profitable export price moves. The estimated price variations are shown in Figure 4.4-1.

Figure 4.4-1 Profitable export price variations determined by sensitivity analysis

(Gas price, CO_2 capture rate, CO_2 sales price, EIRR)



(Note) A figure in red indicates minimum profitable price.

(1) Natural gas price

The purchase price of natural gas as raw material greatly affects the profitable export price of ammonia. Even for the case of Saudi Arabia, which involves the lowest profitable export price (10% EIRR) among the three regions, if the natural gas price rises to \$4/MMBtu, the profitable export price will increase to a level just lower than the Japan's market price (CIF) of \$350/MT. According to the calculation, the elasticity of the profitable ammonia export price with respect to the natural gas price is around between 0.25 and 0.4, although it would also depend on the CO_2 price.

(2) CO_2 capture rate

Full CO_2 capture from ammonia plants involves a higher CAPEX and higher material input than for partial capture, making the profitable ammonia export price higher than that for partial capture. The profitable export price for full capture is \$276/MT while that for partial capture is as low as \$249/MT.

(3) CO_2 sales price

Whether CO_2 captured from ammonia plants can be sold for EOR business or needs to be stored by CCS (with additional cost) greatly affects the economic efficiency of ammonia production. If the CO_2 can be sold at a \$1/t-CO_2 higher price, the profitable ammonia export price is \$1.9/MT lower for full capture.

(4) EIRR

The profitable export price for 7% EIRR is \$258/MT, which is far down from \$276/MT for 10% EIRR, although how much extent the project risk should be taken into account is another point to be considered. On the contrary, when EIRR is raised to 15%, the profitable export price will be as high as \$312/MT.

4.5. Producer Comparison

Based on the analyses above, the features of the CO_2-free ammonia producing countries (regions) can be summarized in Table 4.5-1. The Middle East may certainly have an economic advantage, but is still in its infancy and uncertain about market accessibility (established framework and transparent rules). In this region, most of the major oil or natural gas producing countries do not need CCS/EOR so much at the moment and only have weak incentives to political support or framework design.

Table 4.5-1 Producer comparison

	SAU	Other Middle East	N. America
Accessibility to the market	Unclear	Unclear	Market basis
Feed availability (Price / Policy)	Competitive Domestic demand-supply constraint	Competitive	Henry Hub Market basis
CCS/EOR	Unclear policy (huge potential)	Unclear policy (huge potential)	Linkage with EOR project is needed (huge potential)
CAPEX	-	-	+
Freight to Japan	-	-	+
Challenge for Market Formation	Bilateral dialogue with NOC (governmental support)	Bilateral dialogue with NOC (governmental support)	Business basis Linkage with EOR project for CO2 (financial support)

On the other hand, North America has only low barriers to accessing markets. EOR is already at a commercial stage and natural gas can easily be procured on a market basis. These mean that framework challenges to be overcome to implement the project are few.

Rather, there remain economic challenges including the long transportation distance to Japan and the high production cost. In particular, crude oil price and EOR profitability are the keys to successful business.

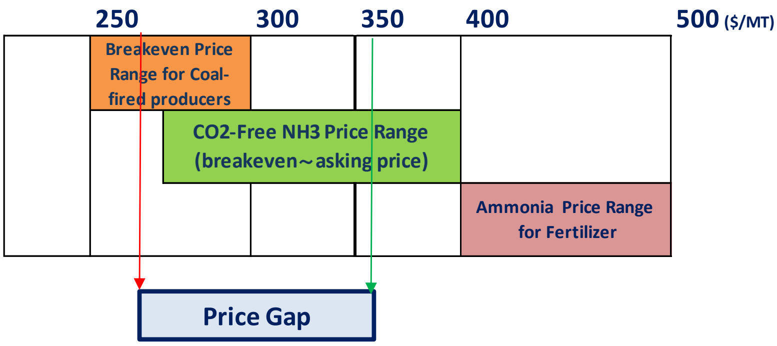
In this way, the Middle East and North America have their own merits and demerits. In order to implement the project in the Middle East, bi-lateral negotiations supported by the governments of the both countries will be needed because Japan's counterparts will be state-run oil-and-gas companies. In North America in turn, EOR is already commercially available, but many EOR projects are usually tied with CO_2 sources. The market has not yet reached a stage where anyone can sell CO_2 freely via pipeline. To establish a new business of capturing CO_2 from ammonia plants and selling to an existing EOR project, it is essential to establish a linkage with the EOR project. It will be thus required to pursue a project that can even embrace an EOR project (including acquisition of upstream interest). When developing a financial scheme, obtaining public support (including participation by government-affiliated financial institutions) would be a key to reducing the equity capital ratio of the project and enhancing the value of investment.

Appendix

The price of "CO_2 free Ammonia", because "Ammonia" is already a commodity commercially traded as feedstock of Fertilizers and Chemicals in a large scale globally, can potentially be influenced by the existing ammonia market pricing mechanism. Commercial producer of "CO_2 free Ammonia" may expect its price to be higher than the existing ammonia market price. On the other hand, from a consumer's point of view (domestic coal-fired power plants in this case), the price of "CO_2 free Ammonia" may be expected to be much lower than the existing ammonia market price based on the calculation results shown by the power generation mix model (in Chapter 2).

That is why there might be the gap between the consumer's and the producer's asking prices as indicated in Figure A. In the first stage of introducing "CO_2 free Ammonia", some fuel incentives by the government might be necessary to meet "supply price" and "demand price".

Figure A Price gap between producers and consumers (projection for 2030, Example)
($/MT, at Japan CIF: delivered to the berth of power station)



(Note) Assumptions

Material price (natural gas):$3.0/MMBtu (75% of Henry Hub price, LNG price (Japan CIF): $560/MT

Coal price (Japan CIF):$100/MT, coal co-firing with NH_3 by 20%, CO_2 emission target: 299 million MT/year

CO_2 marginal abatement cost (=CO_2 price): equivalent to about $50/MT

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