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Assessment of the Decarbonization of Japan's Electricity System
-
A Multi-Perspective Analysis by 2050

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under the directon of
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This master thesis

is dedicated

to my late father

My utmost gratitude goes to my supervisor

Univ.Lektor Dipl-Ing. Dr.techn. Gustav Resch,

who supported me patiently, despite my slow progresses. He gave me the space i needed. His constant mental support and advices helped me to get through this thesis. Without him, i would have given up along the road.

and

special thanks to my proofreader

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Abstract

The decarbonization of Japan's electricity system is an essential component in achieving climate neutrality by 2050. This thesis evaluates the feasibility of a fully decarbonized electricity sector and is divided into three main parts. First, the potential and availability of renewable energy resources, as well as the role of hydrogen and nuclear power in the energy transition, were systematically assessed. Existing studies and datasets were critically analyzed and selectively updated where necessary. Nuclear power and hydrogen technologies were included in the analysis as part of the energy transition, while fossil fuel-based thermal power plants were excluded. Although Japan has limited remaining potential for hydropower expansion, it has substantial untapped potential in solar, geothermal, and particularly wind energy. Second, a cost projection for the levelized cost of electricity of various technologies in 2050 was conducted, based on data from the International Energy Agency and the International Renewable Energy Agency. This analysis provided insights into the economic implications of decarbonization. Hydrogen technologies remain the most expensive due to high hydrogen fuel costs, followed by offshore wind. In contrast, geothermal energy is found to be the most cost-efficient option. Using these findings, along with electricity generation and demand data from the Renewable Energy Institute, a computational model was developed to simulate six scenarios, each emphasizing distinct technological pathways. These scenarios consider the role of storage technologies, such as batteries and hydrogen, in stabilizing the electricity system. The scenarios were evaluated based on technical, economic, and energy security criteria. The results indicate that each scenario presents distinct strengths and weaknesses, highlighting that reliance on a single technological pathway is inefficient for achieving a fully decarbonized electricity system. The thesis concludes with a proposed decarbonization strategy.

The thesis derives four key conclusions: battery storage has a limited impact on required generation capacities but significantly influences overall hydrogen demand; a complete phase-out of fossil fuels is technically feasible; an additional nuclear phase-out, while technically possible, is implausible, reinforcing the government's plan to maintain nuclear power; and despite efforts to expand domestic hydrogen production, Japan will remain highly dependent on hydrogen imports. This highlights the critical role of hydrogen in Japan's decarbonization strategy and the necessity of securing stable international hydrogen supply chains.

Kurzfassung

Die Dekarbonisierung des japanischen Stromsystems ist ein zentraler Bestandteil zur Erreichung der Klimaneutralität bis 2050. Diese Arbeit untersucht die Machbarkeit eines vollständig dekarbonisierten Stromsektors und ist in drei Hauptteile gegliedert. Zunächst wurde das Potenzial und die Verfügbarkeit erneuerbarer Energieressourcen sowie die Rolle von Wasserstoff und Kernenergie in der Energiewende systematisch analysiert. Bestehende Studien und Datensätze wurden kritisch geprüft und gegebenenfalls aktualisiert. Kernkraft und Wasserstofftechnologien wurden als Bestandteil der Energiewende in die Untersuchung einbezogen, während fossil befeuerte thermische Kraftwerke ausgeschlossen wurden. Japan hat nur noch begrenztes zusätzliches Potenzial für Wasserkraft, verfügt jedoch über erhebliches ungenutztes Potenzial im Bereich der Solar-, Geothermie- und insbesondere der Windenergie. Im zweiten Teil wurde eine Kostenprojektion für die Stromgestehungskosten verschiedener Technologien im Jahr 2050 durchgeführt, basierend auf Daten der Internationalen Energieagentur und der Internationalen Agentur für Erneuerbare Energien. Diese Analyse ermöglicht eine Bewertung der wirtschaftlichen Auswirkungen der Dekarbonisierung. Aufgrund hoher Brennstoffkosten bleiben Wasserstofftechnologien die teuerste Option, gefolgt von Offshore-Windenergie. Im Gegensatz dazu erweist sich Geothermie als die kosteneffizienteste Technologie. Auf Basis dieser Erkenntnisse sowie zusätzlicher Daten zur Stromerzeugung und -nachfrage des Renewable Energy Institute wurde ein Modell in MATLAB entwickelt, um sechs Szenarien zu simulieren, die jeweils unterschiedliche technologische Pfade in den Fokus stellen. Diese Szenarien berücksichtigen die Rolle von Speichertechnologien, wie Batterien und Wasserstoff, bei der Stabilisierung des Stromsystems. Die Bewertung der Szenarien erfolgte anhand technischer, wirtschaftlicher und energiewirtschaftlicher Kriterien. Die Ergebnisse zeigen, dass jedes Szenario spezifische Stärken und Schwächen aufweist, wodurch deutlich wird, dass die ausschließliche Fokussierung auf eine einzige technologische Lösung nicht optimal ist, um ein vollständig dekarbonisiertes Stromsystem zu erreichen. Die Arbeit schließt mit einem vorgeschlagenen Dekarbonisierungspfad.

Aus der Analyse lassen sich vier zentrale Schlussfolgerungen ableiten: Erstens hat Batteriespeicherung nur einen begrenzten Einfluss auf die erforderlichen Erzeugungskapazitäten, beeinflusst jedoch den Gesamtbedarf an Wasserstoff erheblich. Zweitens ist

ein vollständiger Ausstieg aus fossilen Energieträgern technisch umsetzbar. Drittens ist ein zusätzlicher Ausstieg aus der Kernenergie zwar technisch möglich, jedoch unwahrscheinlich, was die Regierungspläne zur Aufrechterhaltung der Kernkraft weiter untermauert. Viertens wird Japan trotz Bemühungen zur Ausweitung der heimischen Wasserstoffproduktion stark von Wasserstoffimporten abhängig bleiben. Dies unterstreicht die entscheidende Rolle von Wasserstoff in Japans Dekarbonisierungsstrategie sowie die Notwendigkeit, stabile internationale Wasserstofflieferketten zu sichern.

Contents

List of Abbreviations

AHEAD Advanced Hydrogen Energy Chain Association for Technological Development. 53, 55
AIST National Institute of Advanced Industrial Science and Technology. 18
ANRE Agency for Natural Resources. 14
APS Announced Pledged Scenario. 65, 75

BEVs battery electric vehicles. 51

CCGT combined cycle gas turbine. 95, 96
CSP concentrated solar power. 65, 68, 70

DC direct current. 11
DomH2 Domestic Hydrogen. xiv, 110, 111, 113–116

EEZ exclusive economic zone. 42, 46
EIA environmental impact assessment. 40, 45, 105
EPCO electric power company. 8, 36
EPCOs electric power companies. 7–9, 30, 31, 33–35, 38, 41, 42, 87

FCVs fuel cell vehicles. 51, 52
FiP Feed in Premium. 37
FiT Feed in Tariff. 20, 27, 30–34, 36, 37, 40
FNG fossil natural gas. 26
FY fiscal year. 34, 37

GDP gross domestic product. 6
Geo Geothermal. xiv, 109, 111, 113–116
GWP global warming potential. 25

H2FC Hydrogen Fuel Cell. xiv, 106, 109–111, 113–116, 118
H2T Hydrogen Thermal. xiv, 105–107, 109, 111, 113–118
HESC Hydrogen Energy Supply Chain. 53, 55

IEA International Energy Agency. 3, 4, 14, 61, 64, 65, 70, 73, 74, 76, 77, 114
INDC Intended Nationally Determined Contribution. 2, 50

IRENA International Renewable Energy Agency. 3, 4, 16, 61, 64–68, 70–72, 75, 76, 80, 81, 93, 112

JH2A Japan Hydrogen Association. 51
JWPA Japanese Wind Power Association. 41, 42, 48

LCOE Levelized Cost of Electricity. xvii, xviii, 3, 61, 63, 66, 68, 70–73, 75, 77, 78, 91, 120
LCOS Levelized Cost of Storage. 77, 78, 120
LP gas liquefied petroleum gas. 53

METI Ministry of Economy, Trade and Industry. 8, 14, 21, 40, 55, 73, 92
MOE Ministry of the Environment. 14, 16, 48

NEDO New Energy and Industrial Technology Development Organization. 14, 21, 56
NEF New Energy Foundation. 14, 15
NucGeo Nuclear and Geothermal. xiv, 109, 111, 113–117
NZE Net Zero Emissions Scenario. xvii, 3, 65, 66, 68, 69, 72–75, 77, 114, 120

O&M operational and maintenance. 63, 71, 73, 74
OCCTO Organization for Cross-regional Coordination of Transmission Operators. xvii, 8, 35, 87, 94
OECD Organisation for Economic Co-operation and Development. 68, 72

PES Planned Energy Scenario. 65

REI Renewable Energy Institute. 3, 79–81, 92, 93, 95, 102, 103
RITE Research Institute of Innovative Technology and Earth. 88
RNG renewable natural gas. 26
RPS Renewable Portfolio Standard. 30–32, 40

STEPS Stated Policies Scenario. xvii, 3, 65, 66, 68, 69, 74, 77, 114, 120
SW Solar and Wind. xiv, xix, 107–109, 111, 113–116, 121

UNIDO United Nations Industrial Development Organization. 16

WACC weighted average cost of capital. 68, 72
WEO World Energy Outlook 2023. xvii, xviii, 64, 68, 72, 78, 115, 120

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1 Introduction

1.1 Motivation

A major transformation in the public discussion of environmental awareness can be seen in the last few years. The global warming became a considerable and significant topic among younger but also older generations. The problem itself is already known for a very long time but was mostly neglected in favor of economic growth. The motivation to decrease the greenhouse gas emissions is clear and yet the achievements to this day are probably not enough due to the lack of political involvement until recent years.

First steps into a more climate neutral policy and therefore reducing an anthropogenic climate change were made in the international treaty of 1997 in the Kyoto-Protocol. The first commitment period would not start until 2008 and only 36 industrial countries had made decisions to reduce their emissions. Developing countries ratified that treaty but had no obligations to reduce their emissions at all. The main goal of that first commitment period (2008-2012) was to reduce the greenhouse gas emissions in these developed countries at least by 5% compared to the reference year of 1990. All participants except Canada - which exited from the Kyoto-Protocol - and USA – which never signed the treaty– exceeded their goals. In short, the Kyoto Protocol would seek its participants to reduce greenhouse gas concentration in the atmosphere to a certain extend (UNFCCC, 1998).

A more worldwide participation and commitment was observable in the climate conference of 2015 in Paris (COP21). In this conference it was finally agreed to limit the global warming to a maximum of 2°C compared to preindustrial levels. Further efforts from the participants to limit the global warming below an 1.5°C increase was also introduced. In Order to reach such a challenging goal, greenhouse gas emissions would eventually have to stop completely by the time between from 2030 to 2050. A special report of 2018 published the actual limited budget of permitted CO_2 emissions until those two different temperature goals are reached. For the 1.5°C scenario the global CO_2 emissions is limited to 420 *Gt* CO_2 as of the end of 2017 and 1170 *Gt* CO_2 for the 2°C scenario, which are reached either in approximately eight years[1] or 25 years in consideration the actual emission ratio does not increase (IEA, 2015; Masson-Delmotte et al., 2021)[2].

In the last decade, the necessity for actions against global warming has spread throughout the world and the climate discussion finally became a global problem which has to be solved in cooperation. For this reason, almost every country showed their efforts in the Paris-Agreement of 2015 by submitting their Intended Nationally Determined Contribution (INDC) (UNFCCC, 2015). This new agreement replaced the Kyoto-protocol but, it soon became evident that these efforts were not sufficient to lead the world neither into a 1.5°C nor 2°C path, and therefore in the climate conference of Glasgow in 2021 the Paris-Agreement was reviewed and newer and more ambitious INDCs should be introduced by each country by 2023. The Glasgow conference also elaborated a more detailed guideline, the so-called "Paris Rulebook", which set the regulations of the emission trading system (UNFCCC, 2021).

In this regard, Japan, as one of the largest economies globally, plays a significant role in the global energy transition. Although Japan's share of global greenhouse gas emissions peaked at 3.38% in 1994 and has been decreasing since then, the total amount of emission continued to rise until 2013, reaching 1.35 billion tonnes. Over the past decade, Japan has successfully reduced its emissions by approximately 24%, bringing the total down to 1.03 billion tonnes in 2023 (Jones et al., 2023). This change can be essentially attributed to the aftermath of the Fukushima nuclear disaster in 2011. Japan, which had been significantly reliant on fossil fuels and nuclear energy, reevaluated its energy policy following the disaster, leading to significant efforts to increase the use of renewable energy. The disaster also highlighted Japan's vulnerability to fossil fuel imports and the associated risks to energy security. Given the unique structure of Japan's electricity system and market, the transition to renewable energy sources is exceptionally challenging. Therefore, this thesis seeks to assess Japan's decarbonization pathways under various scenarios. Additionally, as someone of Japanese descent, I have a personal interest in contributing to the discussion on Japan's energy future.

[1]In the period between 2017-2023 almost 370 *Gt* greenhouse gas emissions in CO2 equivalents have been produced (Jones et al., 2023)

[2]These aims were introduced in different scenarios. The INDC, bridge and 450 scenarios. For further Info see IEA, 2015

1.2 Objective

The primary objective of this thesis is to evaluate how Japan's electricity system can be decarbonized by 2050 under different scenarios. The thesis considers various renewable energy sources and emerging technological advancements that may assist the country's transition toward climate neutrality. It also systematically investigates the potential of available renewable energy resources and projects their future role. Through computational modeling, different scenarios are compared to determine the feasibility of a fully decarbonized electricity system and to identify the challenges that need to be addressed.

1.3 Methodology

This thesis follows a structured approach, divided into three main parts:

- Literature review and energy potential assessment: A comprehensive literature review was conducted to analyze the potential of Japan's renewable energy resources, including hydropower, geothermal energy, bioenergy, solar power, and wind energy. The role of hydrogen in the energy transition was also considered. Existing studies and datasets were critically analyzed and updated, in particular, for bioenergy, an older study was updated with new data to enhance the accuracy of the potential assessment. Nuclear power and hydrogen were included into the research as part of the energy transition, while fossil-fueled thermal power was excluded.
- Cost projection and scenario analysis: The second part of the methodology involves a long-term cost projection extending to 2050, using data from the International Energy Agency (IEA) and the International Renewable Energy Agency (IRENA). Information on the projection of installed capacity and current costs were taken from IEA scenarios - the Stated Polices Scenario (STEPS) and Net Zero Emission Scenario (NZE) - and IRENA's database, and were used to calculate the Levelized Cost of Electricity (LCOE) for different energy sources, thereby providing a quantitative assessment of the economic impact of the decarbonization process.
- Electricity system modeling in MATLAB: The third and final part of the thesis involves the development of a computational model in MATLAB. This model uses hourly electricity generation data from the Renewable Energy Institute (REI) for Japan from 2017 to 2023. It enables the scaling of distinctive capacity targets and projects electricity demand in 2050 based on the REI data. The algorithm was developed to balance electricity supply and demand under different scenarios.

Six distinct scenarios, each characterized by specific technological pathways and different capacity targets for renewable energy were created. Additionally, these scenarios consider the potential role of energy storage solutions, such as batteries and hydrogen, in supporting the overall energy system. Finally, the scenarios were evaluated based on technical, economic, and energy security related criteria.

The main assumptions for this thesis are based on official data from the IEA and IRENA. Additional sources, such as scientific publications, governmental white-papers and online articles, were used to supplement data and key assumptions. More detailed explanations of the methodology and assumptions for the individual parts will follow in subsequent chapters.

1.4 Structure of the Thesis

This thesis is structured into six chapters, each contributing to a comprehensive assessment of Japan's electricity system decarbonization by 2050. Chapter 1 introduces the research topic, outlining the motivation, primary objectives and the methodology of this thesis. As described in the methodology, the thesis is divided into three main parts. The first part, focusing on literature research, is covered in Chapters 2 and 3. Chapter 2 provides a brief overview of essential background information on Japan and its current electricity system, while Chapter 3 analyzes the potential of renewable energy technologies, considering their historical development, current status, future prospects, and associated challenges. The second part of the thesis is addressed in Chapter 4, which projects the levelized costs of electricity for the individual technologies in 2050, primarily based on assumption from IRENA and the IEA. Chapter 5 presents the third part of the thesis, explaining the developed model and the simulated scenarios and the resulting assessment of the scenarios. The last Chapter 6 provides conclusions regarding renewable energy potentials, cost projections, and scenario assessments. Furthermore, it discusses model limitations, key findings, and suggests a decarbonization pathway.

2 General Overview

This chapter will give a short overview of the country specific basic knowledge about climate, topography and population. This allows to recognize possible renewable energy potentials or limitations as well as future trends in energy demand. Additionally, a short introduction to Japan's electricity systems with its characteristics will be discussed.

2.1 Country and Climate

Japan is an archipelago consisting of over 14,000 islands with the five main islands from North to South, namely Hokkaido, Honshu, Shikoku, Kyushu, and Okinawa. To be more precise, Japan's land area was formed by the shifting of the plate tectonics, resulting in a mountain chain, where only the top of these rises from the sea (Schwind, 1981). The terrain is hilly, full of mountainous regions and has around 100 active volcanoes (Stefansson, 2005). About three-quarters of the total area is mountainous, and even the sea is quite steep. The seabed drops rapidly to 7000-9000 *m* in 90 *km* to 150 *km* from the Pacific coast (Statstics Bureau Japan, 2023; Matijević, 2012).

The climatic conditions vary significantly since the fringe of islands spreads from the 20 to 45 degrees north latitude. This complies approximately to Cairo in the south to Venice in the north. In all, Japan has six different climatic zones with two monsoons, which describe seasonal changes in precipitation and atmospheric circulations. One is in the winter and one is in the summer. The impact of the respective monsoons varies depending on the region. The winter monsoon brings humid conditions with heavy precipitation, particularly to the northwestern region, and lasts from November to February. The summer monsoon is divided into three parts. The first part begins in June and is also called "tsuyu". It lasts about four to six weeks and describes the classic rainy season, which is followed by the second part, the hottest and dry days of summer. The last part is at the end of summer in September and is known for its many taifuns. Regions with the greatest impact on the summer monsoon are the southwestern regions. In summary, it can be said that the climatic conditions in Japan have a major influence on the energy demand in Japan (Stefansson, 2005; Statstics Bureau Japan, 2023).

2.2 Population

The population peaked in 2009 at 128 million people and is declining since then. In 2022, it decreased to less than 124 million people. According to the newest United Nations World Population Prospect 2022, this trend will continue further. In different scenarios considering fertility, mortality, and migration, the population in 2050 will range between 96.6 to 114.7 million people, with a medium of 103.7 million people. Another observation is that the population is growing older. While only 12.5% of the population was older than 65 years in 1990, it is now 29.8% in 2021, and in 2050, it will be between 34.1 - 41.6%. The medium age range in 2050 will be 50 - 58 years in Japan (UN, 2024).

The declining and aging population could have a great positive impact on the greenhouse gas emissions for several reasons. The first assumption is that fewer people produce fewer greenhouse gas emissions. The second assumption is that a greater share of the population will be in retirement, which will have an impact on the gross domestic product (GDP) and the energy consumption from the industry will most certainly decrease (O'Neill et al., 2010). The third assumption is that there will be a change of choosing the individual transportation method. The majority of retired people will not move by car but by public transportation, which could reduce the greenhouse emissions (Kii et al., 2021; Zhang et al., 2021).

2.3 Overview of Japan's Electricity System and Regulations

Japan's electricity sector is defined by distinctive features shaped by both historical developments and geographical constraints. The absence of international grid connections, coupled with the division into distinct regional grids with limited cross-regional capacity, poses significant challenges for grid stability. Furthermore, Japan's limited domestic natural resources have a significant impact on its energy security strategy. This section provides an overview of Japan's electricity system, regulatory framework, and market competition, highlighting efforts to enhance efficiency and resilience.

2.3.1 Electricity System

Japan's electricity grid has very unique characteristics. First of all, it has no connections to foreign countries, thus forcing it to balance supply-demand itself (IEA, 2021). The supply voltage is 100 V, which is the lowest in the world (FEPC, 2014). The grid is also divided into a western and eastern zone, which uses different operating frequencies. While the west of Japan is using 60 *Hz*, the eastern part of Japan uses 50 *Hz* (Yoshida et al., 2018; IEA, 2021). This problem originated in the purchase of generators from different makers from different countries in the early days when the electricity system was still a local phenomenon. The supplier for the 50 *Hz* zone was AEG from Germany in 1895 and General Electric from the USA for the 60 *Hz* zone in 1896 (FEPC, 2015). The two grids are coupled by three high voltage direct current substations, which convert the frequency and have a limited transfer capacity of 1.2 *GW* (IEA, 2021). Lastly, the grid is built up and ruled by ten big private companies. These are the former electric power companies (EPCOs). Each of them has its own service area, where they can be seen as a monopoly in each of their designated regions (see Figure 2.1). As these monopolistic entities have no incentive to allow external competition within their designated regions, the interconnection capacity between these areas remains highly constrained. The power grid of Japan is therefore split into these ten smaller grids (Yoshida et al., 2018; IEA, 2021). Unlike in Europe, where power can easily be transported in a very wide range and thus balance out demands and electricity production, this is nearly impossible for Japan, making the grid rather unstable for huge demand changes (METI, 2018). This problem was seen in 2011, when the Tohoku earthquake and tsunami hit and destroyed the nuclear power plant in Fukushima. Eleven reactors with a combined power of 9.7 *GW* were taken offline. The limited interconnection capacity between the regions and grids (50/60 *Hz*) acted like bottlenecks and were insufficient to compensate the huge power loss in the Tohoku area. If not for the bottlenecks, there would have been enough extra capacity in the west (Yoshida et al., 2018). The results were huge blackouts in eastern Japan. This incident made the government rethink their energy security and safety strategy.

electric power companies

2.3.2 The 3E+S principle

After experiencing two major crises over the last 40 years, Japan reassessed its energy security. The first was the oil crisis of the 1970s. Japan depended tremendously on oil imports at that time. The government's response was to strengthen the nuclear fleet, as the needed fuel is comparably low. In their opinion, it is even considered a domestic resource, as fuel can be reprocessed, reducing the necessary imports even further (Yoshida et al., 2018). As nuclear energy was also considered environmentally friendly, this was also Japan's main tactic in mitigating greenhouse gas emissions. Until 2010 the nuclear fleet grew to the third largest fleet in the world (World Nuclear Association, 2016) with 53 reactors and contributed approximately 30% of the total electricity generation in Japan with even further expansion plans to 40% by 2017 and 70% by

2030 (Yoshida et al., 2018). However, the second crisis, the Fukushima earthquake and tsunami in 2011, showed several flaws in Japan's reliance on nuclear power plants. One of the aspects was the already mentioned neglected cross-regional supply capacities. With those two crises, Japan changed their approach for energy security and safety, to follow now the 3E+S principle. These letters stand for: economic growth, energy security, environmental sustainability, and safety. The fundamental objective is to enhance resilience against disasters and abrupt shifts caused by resource scarcity or geopolitical developments by diversifying energy sources and strengthening self-sufficiency. Future actions have to maintain these aspects consistently. In this frame, among other things, it was decided to deregulate the electricity grid (Yoshida et al., 2018; METI, 2018).

2.3.3 Deregulation and Liberalization

The deregulation process was carried out as a three-step process from 2015 - 2020. In the first phase, the Ministry of Economy, Trade and Industry (METI) established the Organization for Cross-regional Coordination of Transmission Operators (OCCTO) in 2015. Before Fukushima, the main approach for energy security was based solely on securing supply chains for fuel inputs. OCCTO's function is to review supply-demand forecasts and coordinate transmission energy between the regions to strengthen the energy grid security. Furthermore, in addition to monitoring, they also plan for necessary grid investments. For instance, there are development plans for the earlier mentioned 1.2 GW east-west (50-60 Hz) connection to increase to 3 GW by 2028 (IEA, 2021). A standardization of the east-west grid was never made due to the roughly estimated high-cost factor. The unification is assumed to cost more than 10 trillion Yen[1] for the electricity utilities (AHK Japan, 2022).

The second phase of deregulation was opening the market by expanding full retail competition to the residential sector in 2016. By 2018, more than 380 companies had joined the liberalized market, where most of these enterprises were interested in operating cheap coal power plants. In October 2020, the number of companies increased to 684. However, the ten major EPCOs still dominate the market (AHK Japan, 2022). The third and last phase involved the unbundling of the transmission and distribution sectors in 2020 (Yoshida et al., 2018, ANRE, 2015).

OCCTO also regulates the distribution of interconnection costs for new market entrants. This makes it easier for new companies to share the grid connection cost, which previously they had to negotiate bilaterally with the designated electric power

[1]approximately 62 billion EUR (1 EUR = 161 Yen, 17.1.2024)

company (EPCO). Especially regions like the Tohoku or Hokkaido area with abundant wind and solar energy but low demand benefit from this, as with the reforms, demand centers like Tokyo and the Kansai area can be supplied from such remote places with the possibility to introduce renewable energy in particular (Yoshida et al., 2018). The fear of unjustified charged high connection cost by one private monopole to avoid competition is therefore eliminated. However, grid constraints are still not completely abolished, since the legal structure for the unbundling of the transmission and distribution allows the EPCOs to retain a holding company structure, where the network operations are managed by a subsidiary company, while the main company participates in the generation and retail market (Yoshida et al., 2018). This allowed the monopolistic energy providers to maintain parts of their power in their respective grid and hinders further introduction especially for smaller-size volatile renewable energy resources. By law, the network operators are obliged to let new producers with a greater supply of 50 kW or more into the grid, unless the grid stability is at stake, which the monopoles justify their constraints with this issue. For smaller producers (less than 50 kW) it is almost impossible to get grid access without having a personal connection with the monopole utility (IEA, 2015, AHK Japan, 2022).

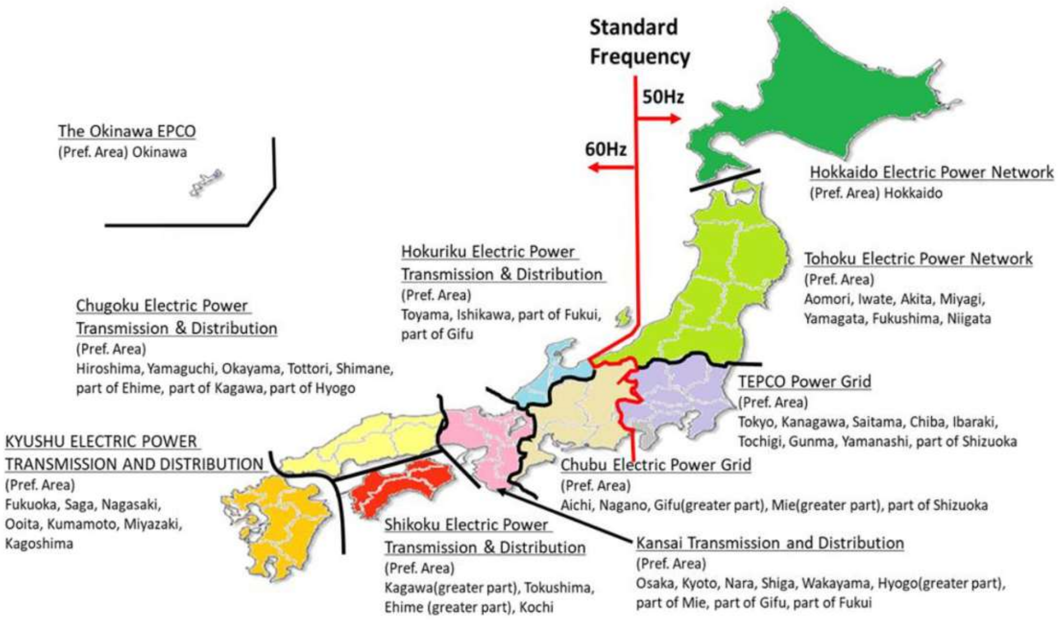

Figure 2.1: Japan's electricity grid with two different frequency zones and ten smaller grids, each operated by one of the electric companies of Japan. (Source: OCCTO, 2022a)

3 Japan's Potentials in Renewable Energy

The possibilities of how to meet electricity needs of each country using carbon-neutral energy sources depend significantly on its topographical and climatic conditions. For this reason, a more comprehensive analysis of the individual renewable energies is essential. This chapter focuses on the historical development, the status quo, the future potential and the difficulties of the various renewable energy technologies in Japan. Furthermore, social aspects such as the acceptance of a technology are also taken into account.

3.1 Hydropower

Hydroelectric power generation has a long history in Japan. Although the first ever built power plant was the coal-fired power station Kayabacho in Tokyo with 25 kW in 1887 (ANRE, 2018), it was followed only one year later by the Miyozawa hydropower plant with 5 kW direct current (DC) in Miyagi Prefecture (Kitamoto, 2024). However, since the start of operation Miyozawa is not confirmed (suiryoku.com, 2024), the first hydroelectric power plant is said to be the Keage power plant in Kyoto starting operation in 1891 four years after the Kayabacho (ANRE, 2018). This plant is still operating today, but with an increased output from initial 160 kW to 4.5 MW in 1979 (KEPCO, 2018).

3.1.1 History of Hydropower in Japan

Evidently hydroelectric power plays a significant role in Japan's power generation history. In fact, it became the dominating power source for electricity until the 1960s (Mitsumori, 2020). In 1935 the share of power generation was 55% (Lecler and Brombal, 2017; Shiraishi and Inoue, 2010) and in 1955 it rose up to 61% with more than 10 GW (Lecler and Brombal, 2017). However, after the second World War until the end of the Cold War, Japan's economy boomed and it soon became, right after the United States, the second largest economy in the world. This economic growth caused a high demand in electricity. At this time, mainly thermal power facilities were built to satisfy the massively increasing demand and oil displaced hydropower in 1963 as the major energy source (Mitsumori, 2020), even though hydropower had doubled its generation between the 50s and the 80s (Lecler and Brombal, 2017). The oil dependency grew to 73% in 1976 (Lecler and Brombal, 2017), and the two-oil crisis in the 1970s forced Japan to rethink its energy policy. The government prioritized nuclear power since 1973 (Mitsumori, 2020; Lecler and Brombal, 2017; World Nuclear Association, 2024b; Yoshida et al., 2018), with the first nuclear power reactor going online in 1966 (Yoshida et al., 2018), and raised its electricity generation share to some 30% until 2011 (World Nuclear Association, 2024b; Yoshida et al., 2018), with plans to increase it even further to 40% by 2017 (World Nuclear Association, 2024b), while the share of hydropower with 34.27 *GW* capacity fell to 17% in 2005 (Lecler and Brombal, 2017) as seen in Figure 3.1. With this strategy Japan addressed the two main issues: First, the energy dependency from foreign countries (Lecler and Brombal, 2017), as Japan sees nuclear power as a domestic energy form, since spent nuclear fuel could be reprocessed and thus enhancing the energy security by reducing the need for imports (Yoshida et al., 2018). Secondly, nuclear power has compared to fossil fuels environmental benefits and therefore it was and still is seen as a solution to the global warming issue (Yoshida et al., 2018; Lecler and Brombal, 2017).

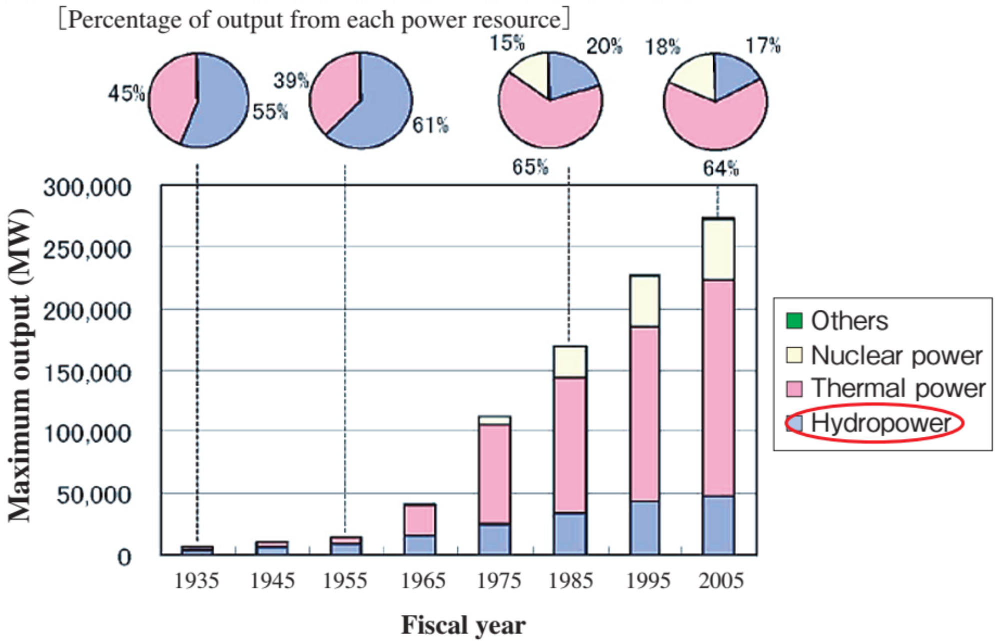

Figure 3.1: Transition of the power output between 1935-2005 by resource (Source: JCOLD, n.d.)

In 2011, after the Fukushima accident, there has been great resistance from the public against nuclear power, forcing the government to shut down all the existing 54 nuclear power plants. This great loss of electricity generation led again to the dependency on oil, peaking to 88% in 2014 (Lecler and Brombal, 2017). The response this time was to focus on renewable energy (Mitsumori, 2020), but also restarting parts of the nuclear power plant fleet, with the first two reactors coming back online in 2015 and a nuclear electricity generation share plan of 20% by 2030 (World Nuclear Association, 2024b).

Hydropower never vanished from the surface but was merely displaced as the main energy source due to the fast-increasing demand. Until the 1980s hydropower capacity grew considerably and it would begin to slow down in the 1990s, since most of the possible sites (1162 sites) for large hydro power plants had been considered as already exploited economically in 2005. Remaining sites are too difficult to reach for construction to make it cost-effective (Lecler and Brombal, 2017).

However, why has there been a shift from hydropower to oil in the first place?

According to Inoue, electricity generation from oil[1] was slightly more expensive in the 1960s than that of hydropower[2] (Shiraishi and Inoue, 2010). This shows that the costs were not the sole reason for the transition. It was the shorter construction time. While it is comparably easy for thermal power plants to be built almost anywhere and in a relatively short time, hydropower has to overcome many obstacles, and thus having a very long lead time until electricity can finally be generated. The most famous case for Japan might be the Yamba-Dam, which would take 68 years from planning to operation. Its original purpose was flood prevention, but the original plan from 1949 was revised several times and after completion in 2020 it also serves as water supply and electricity generation (Nikkei Newspaper, 2020). Obstacles can be very different, but often construction is postponed due to oppositions from the locals and politics. Others are prevention of water pollution or preliminary works, like relocating roads, railroads, and homes. Besides the Yamba-Dam there are many other sites that took several decades to build or are still "under construction". This makes a power generation shift from hydro to other forms, in Japan's case to oil, despite the higher generation cost only logical.

Another reason why oil replaced hydropower as the main source might be the fact, that many dams were built, especially in the post-war period, which had different purposes, like flood control or water supply, and not necessarily for electricity generation. So even though there might have been many dam projects they did not contribute to power generation at all (Lecler and Brombal, 2017).

[1] 10-17 yen/kWh
[2] 8-10 yen/kWh

3.1.2 Hydropower Potential in Japan

As almost all possible sites were considered as exploited in 2005, the government began to reevaluate their hydropower potential in the mid-2000s, and launched surveys carried out by several organizations to estimate additional but also unused potentials at existing sites (Lecler and Brombal, 2017). Those surveys confirmed that new sites for large-scale projects are limited, but there is still potential, especially in smaller scale facilities. Comparison between those surveys are difficult since there is no official classification of hydropower generation by output in Japan. While the Agency for Natural Resources (ANRE), a part of the METI uses the same definition as the IEA, the New Energy and Industrial Technology Development Organization (NEDO) or the New Energy Foundation (NEF) use their own classification for their surveys.

In short, it can be said that there is a large number of unused potentials in smaller scale sites with mostly <1 MW but also some <30 MW. Great potential lies mainly in the untapped water-channels, but there is furthermore potential in unused heads at existing dams, which were built for other purposes than electricity generation. Although in latter one those unused heads are often lower than 5 m, which makes the economical utilization with current technologies questionable (Lecler and Brombal, 2017), there alone is said to be a cumulated potential of 330 MW[3]. 958 of 1389 these sites are micro-scale facilities with less than 100 kW (Shiraishi and Inoue, 2010). New technologies are on their way to make those sites economically viable (Lecler and Brombal, 2017).

As already mentioned, the greater potential was estimated in the approximately 2700 untapped water-channels, mostly less than 30 MW, with a total capacity of 12 GW. These values originate in the fifth hydropower research conducted by METI in 1980 and did not change in newer surveys carried out by NEDO in 2004 and again in 2012 by ANRE (Shiraishi and Inoue, 2010; UNIDO and ICSHP, 2013). Mountain streams and small rivers were excluded, since they are presumed to be economically inefficient, therefore neglecting those potentials and distort the real theoretical potential (UNIDO and ICSHP, 2013). The Ministry of the Environment (MOE)) however, estimated 19,686 untapped sites with an output capacity of 8,982 MW in river channels in 2011 (see Figure 3.2). Most of these sites have less than 5 MW. These significantly different numbers to the previously mentioned surveys shows that many sites have been neglected, with a strong indication that especially smaller than 1 MW sites have not been considered (MOE, 2012).

Those numbers by MOE are reaffirmed, when considering already built small scale facilities. According to ANRE, there were 1369 sites in operation in 2012 with an output

[3]There are two different information about the energy production: ~27.449 TWh(Lecler and Brombal, 2017) and 1.7 GWh (UNIDO and ICSHP, 2013).

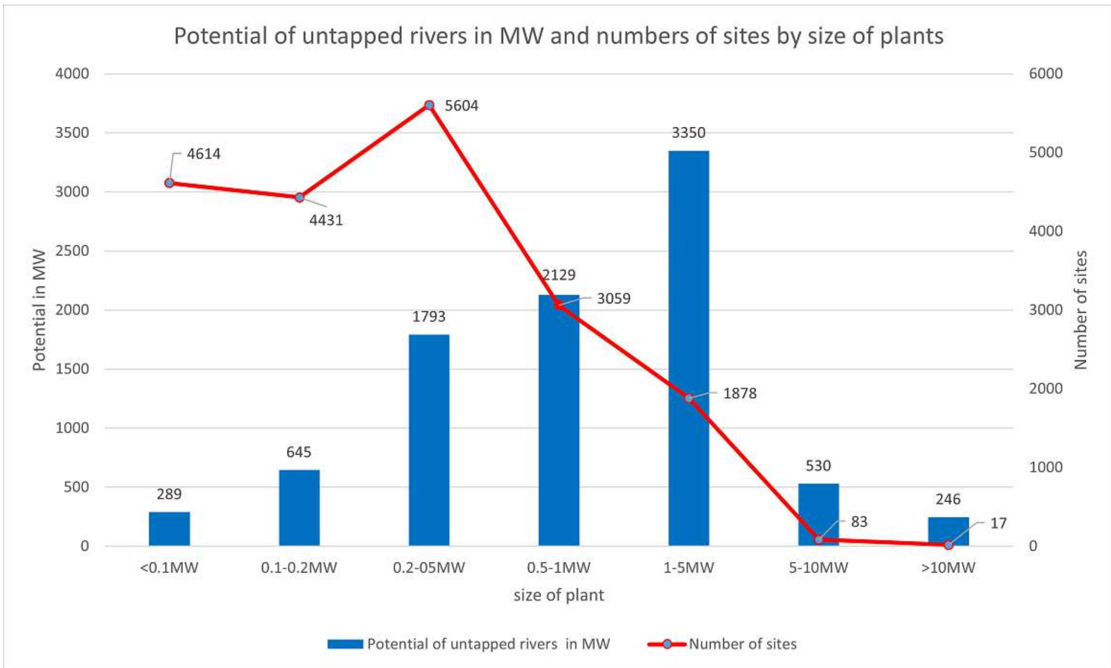

Figure 3.2: Hydropower potential according to the Ministry of Environment Survey in 2011 (Source: MOE, 2012)

less than 10 MW for each site. They together contribute for 3.518 GW or 18.802 TWh[4]. The still undeveloped part has an additional potential of an output of 6.749 GW and an annual electricity production of about 27.449 TWh[5] in small hydropower facilities below 10 MW (UNIDO and ICSHP, 2013). This means that approximately only one third out of 10.267 GW has already been installed. However, according to NEF in 2010 there were 1754 small and medium sized with less than 30 MW in operation. Their output capacity is 9.627 GW or 47.25 TWh (Lecler and Brombal, 2017). Especially if latter is looked more closely, then it shows that the majority of these sites are small facilities with less than <1 MW output. Many sites were built in the period between 2003-2013 (see Figure 3.3). Two facts can be driven out of this. First, smaller sites are indeed considered, developed, and used by local organizations or individuals. Secondly, in some surveys smaller sites and their potentials are completely neglected in the statistics. One reason could be the economical aspect. The distribution infrastructure cost stays the same, whatever the size of the facility is. Smaller sites are therefore unattractive for power companies and bigger sites are preferred. For this reason, it is

[4]This results in a capacity factor of 61%
[5]This results in a capacity factor of 46%

one of the keystones for the government to set the most suitable incentives to promote hydropower. In the final conclusion of the MOE survey, it is pointed out that small facilities could represent 14.57 GW by 2050 if all potential sites $<30\ MW$ are developed (Lecler and Brombal, 2017).

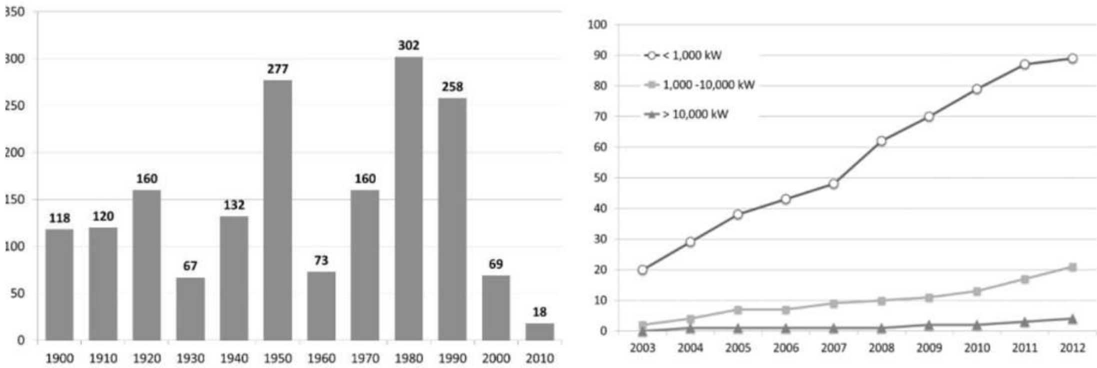

Figure 3.3: Left figure: Number of hydropower site per year of operation start with $<30\ MW$,pump-storage excluded, between 1900s and 2010s, right figure: Number of hydropower site since 2000s by size (Source: Lecler and Brombal, 2017)

3.1.3 Conclusion on Hydropower

The United Nations Industrial Development Organization (UNIDO) sees an overall theoretical potential of about 136,42 TWh[6] for hydropower in Japan (UNIDO and ICSHP, 2013). According to the IRENA database, Japan already produced about 89 TWh in hydropower (inclusive pumped storage) in 2021, which leaves an open potential of approximately 48 TWh (IRENA, 2024b). It is clear that hydropower is well developed in Japan and that there is only limited potential left, but with the new findings the government tries to enhance the penetration of hydropower electricity generation to - in their belief - to the maximum extent. There are many dams in Japan, which main purposes are not for electricity generation but either flood prevention and/or water supply. Some of these dams are already extended by electricity generation facilities, but still not all. The government therefore promotes the installing of such power generation facilities and/or increase the output at existing sites (METI, 2018).

The different classifications makes a concrete and precise conclusion about the actual hydropower potential difficult. It is also questionable if Japan will use their potential of the 400.000 km of untapped river channels (UNIDO and ICSHP, 2013). The final

[6] 19% of the 718 TWh gross theoretical hydropower is supposed to be exploitable

findings of the hydropower potential in Japan is a rough estimation and is given in Table 3.1, where the capacity factor is derived from the values of the installed capacity and the energy production.

	potential range	c-factor	est. e-gen. potential
Untapped river channels	6.7 - 12 GW	46.4 - 61.0%	27.2 - 64.1 TWh
Unused heads in dams	330 MW	-	1.75 GWh

Table 3.1: Estimated unused hydropower potential in Japan

3.2 Geothermal Energy

The government of Japan recognizes geothermal energy as one of its cornerstones in reducing greenhouse gas emissions by 2050. This is shown in the "Outlook on National Energy & Environment Strategy for Technological Innovation towards 2050" (Hirai et al., 2016). The cornerstones in this outlook can be divided into four groups, namely energy saving, energy storage, energy production and finally carbon capture. In these terms geothermal energy will play an essential role in energy production. Although there are many other resources for energy production the cabinet office of Japan only mentions photovoltaic and geothermal in that outlook. Thus, the assumption that the government sees great future potentials in geothermal energy production is more than given. Japan expects with these cornerstones a reduction of several to 10 billion tons of CO2-emission (Hirai et al., 2016).

3.2.1 Potential of Geothermal Energy in Japan

Data from 2009 from the Japan's National Institute of Advanced Industrial Science and Technology (AIST) shows that Japan has one of the largest capacities for geothermal energy production. Right after the United States with an estimated 30 *GW* and Indonesia with around 27.79 *GW* Japan comes third with approximated 23.47 *GW*. It is followed by the Philippines and Mexico which both have 6 *GW* (Koshiba, 2009). Stefansson stated 2005 that these facts were already known in the 1980s. In his research he found that the geothermal energy potential is directly related to the number of active volcanoes (Stefansson, 2005). These results were driven by an "volumetric potential evaluation" method, which is supposed to be practically the only substantial evaluation method (Asanuma et al., 2021). The usable energy depends on the temperature of the source. Sources with Temperatures beneath 130°C can only be used directly as a heat source but it is not suitable for electricity production. Stefansson assumes a conversion loss of 90% (Stefansson, 2005).

3.2.2 Problems of the Development of Geothermal Energy in Japan

Although, it is known for decades that Japan has great potentials of geothermal power, the installed capacity still remains only at 0.5 *GW* (Asanuma et al., 2021). Why is that? Among other things, this was researched by the University of Kyushu between the period of 1970-2020. One part of their research included the historical analysis of supporters and opponents of geothermal energy by looking into old articles in local and national newspapers in previously mentioned period. For their results they took a geothermal project in Oguni Town in the prefecture of Kumamoto located in the southern area of Japan. Their founding of the social acceptance for this region and case can be divided into three periods. The first period 1970-2002 is marked by the complete rejection of the population, except for a couple of stakeholders. Especially the depletion of hot spring were the main concerns[7]. Oppositions of the population were also found in several other projects throughout Japan. In the second period 2002-2011 of the Oguni Town geothermal project there was no article found. The community experienced continuous community divisions. It could be possible that in this period the project was also stalled and that the focus of the community lied elsewhere. After the Fukushima Incident the community gradually changed their view on energy production, which marked the third period 2011-2020. The community acquired a strong community acceptance for the geothermal project in 2015-2016 (Komori, Kioka, and Nakagawa, 2023). The case of the Oguni Town may be only one project, however it represents how the social acceptance made a significant change especially after the Fukushima earthquake. Another essential aspect for a positive social acceptance is to include the community into projects while respecting the culture and traditions of the local citizens, since only one opposing individual can already have a huge impact especially in rural communities in Japan. When it comes to geothermal power plants these persons are usually hot spring inn managers. Considering the fact that Japan has a very strong bath culture, the tourism depends strongly on the hot springs. This is why stakeholders such as hot spring inn managers have great influence in decisions made by the local governments, which expect substantial revenue from tourism related to onsen. Hence, it is very important for developers to communicate continuously, not only about risk preventions, control or the reversibility, but also about the benefits of geothermal power generation to overcome the anxiety for these stakeholders. Underground structures are highly unpredictable and is always site-specific and thus risk evaluation and management are key issues to get positive responses for drilling permits (Kubota et al., 2013).

Although the Fukushima-Dai-Ichi Nuclear Power Plant incident shifted the energy policy away from nuclear-oriented to a more renewable policy, the installed capacity of geothermal power generation has yet remained very low at around 0.5 *GW* as of 2019 and had not changed since 1995 (Komori, Kioka, and Nakagawa, 2023; Asanuma et al., 2021; GRSJ, 2020). In 2010 the geothermal energy production contributed with 3064 *GWh* only 0.2% of the total energy production in Japan. The Great East Japan Earthquake in 2011 showed that geothermal power plants were restored quickly and therefore seismic risk can be considered to be relatively low (Kubota et al., 2013). So why is that there is yet no installed capacity? Considering the time scale, the 2011 earthquake passed only “recently”. The neglected development and research in this field for decades until 2011 due to the focus on a nuclear-based society is now showing and therefore the lead time of 15 to 20 years for geothermal power plants from

[7] winter 1994

planning to starting the plant is enormous (GRSJ, 2020). As a consequence, there is a lack of development facilities and young capable personnel. Although seismic risks appeared to be relatively low than thought, geothermal energy still is connected to high risk. Next to the development risks, such as drilling failures due to the heavy stress on the drilling equipment caused by high temperatures, the financial risks are also high. 50% of the total costs is for identifying and characterizing reservoirs. An accurate reservoir evaluation is generally only possible after an actual drilling is performed, which is why large investments are necessary as resources are often in mountainous regions with no access to roads or electricity. Pipelines and Plants make 40% of the total costs (Barbier, 2002). It should be mentioned that 81.9% of the total geothermal potential is estimated to be located in national parks, which is why the Ministry of Environment loosened the restriction regarding the development for geothermal power plants (Kubota et al., 2013). Clearly the development costs for infrastructure take most of the initial investments, which makes geothermal energy compared to others very expensive and the high degree of uncertainty arising from numerous risk factors further reduces its economic viability. Given these circumstances the government decided to offer subsidies for drilling for geothermal energy introducing the new Feed in Tariff (FiT) System in 2012[8]. The new plan was to guarantee debt incurred to fund drilling for a period of 15years with 27.3yen/kWh (>15 MW) and 42 yen/kWh (<15 MW). With these measures the government aims to threefold the installed capacity (Kubota et al., 2013). This corresponds to the 1.0-1.1% power generation mix aim for fiscal year[9] 2030 of the anticipated total electricity generation of 934-1065 TWh for 2030 (ANRE, 2021c). If a capacity factor of 70% is assumed, then the needed capacity would be 1.52-1.91 GW.

3.2.3 Future Technological Developments in Geothermal Energy

At the present commercial geothermal power plants are using mostly the hot dry rock method. After drilling up to 3.5 km deep, water is injected with high pressure and cracks form in hot dry rocks, resulting in very thin channels through which the water or other working fluids can flow and is warmed up to 350°C. Via a second drilling hole the hot water is then pumped up. The working zone of these power plants lies within the so-called brittle zone of the earth's crust. However, the main issue is that the fracking process cannot be aimed into the wanted direction but is on the other hand arbitrarily. The consequence are many unwanted cracks where the water leaks, losing

[8]The former support until 2012 under the renewable portfolio standard, which required electric utilities to generate an obligatory percentage of electricity from renewable sources, was only valid for binary cycle, but not for single and double flash power plants.

[9]Japanese fiscal year (FY) starts April 1st and ends on March 31st of the next calendar year.

at least 50% of the working fluid into the ground (Asanuma et al., 2021; Muraoka et al., 2014). It is needless to say that the total efficiency is reduced tremendously.

In 2010 "The Japan Beyond-Brittle-Project" was initiated and feasibility studies has been started, to overcome that problem (Muraoka et al., 2014). The main idea is to drill deeper, to pass the brittle zone and to reach at least the brittle-ductile transition zone or even go beyond to the ductile zone. In later zone the rock is less likely to fracture but to deform ductilely. While the upper brittle-ductile zone can be used to upgrade existing power plants and thus increase productivity and provide sustainability, the lower ductile zone would make better isolated reservoirs with far lesser water losses. Another benefit is, that the ductile zone is safer since earthquakes with damaging magnitudes are supposed to not occur in reservoirs in ductile rock masses (Asanuma et al., 2021).

Another reason for deeper drilling is the temperature rise, thus making geothermal energy extraction more efficient than current shallow drilling methods. Low temperature power plants are normally used directly as heat source. Indirect use, namely the electricity generation, is technically possible but not economical. This feature is reserved for high temperature power plants because the efficiency is limited to the temperature difference defined by the Carnot-cycle. Although the global average geothermal gradient is around +3°C per 100 m, it can locally deviate significantly. In Japan this value can surpass ten times the average value in these geothermal areas. Based on the geothermal gradient, this type of investigation is called geothermal exploration and is also used to explore hot springs or ground water (Kyushu University, 2016). Japan with over 100 active volcanoes is rich of such geothermal areas[10]. As a consequence of the rapid high temperature rise, it reduces the necessary drilling depth, which makes it technologically easier and more economical. Actual experimental drilling under the Beyond Brittle Project has been carried out since 2018 mainly by the New Energy & Industrial Technology Development Organization (NEDO) and further by the Ministry of Economy, Trade and Industry (METI). Analysis have discovered that the brittle-ductile zone in the Tohoku Region in Northeast Japan is shallower than those in other subduction zones and less than several kilometers (Reinsch et al., 2017; Okamoto et al., 2019). Another investigation beneath a volcano showed, that there is a rock body in the brittle-ductile zone with the possibility of a temperature of more than 400°C and several percent of brine (Ogawa et al., 2014). The origin is assumed to be sea water and magma. These kind of rock bodies in the brittle-ductile transition zone should contain liquid in supercritical conditions, and subsequently huge amount of thermal energy (see figure 3.4). Such supercritical geothermal resources are capable of generating more than several tens of Gigawatt of electricity for three decades (Asanuma et al., 2021, Okamoto et al., 2019). However, the technological challenges to deep drilling

[10]The country has 188 volcanoes (Muneer, Jadraque Gago, and Etxebarria Berrizbeitia, 2022)

are yet to overcome. Current drilling technologies may already be able to reach the brittle-ductile zone, but it still needs efficient cooling technologies and pressure management (Asanuma et al., 2021). Further problems are the acidic geothermal fluids, which affects the drilling materials by corrosion. It is clear, that the lack of research and development in geothermal energy in favor to the nuclear power is delaying a new type of geothermal power plants, and therefore the operation of a pilot plant under the "The Japan Beyond-Brittle Project" has only a target year of around 2040 (GRSJ, 2020).

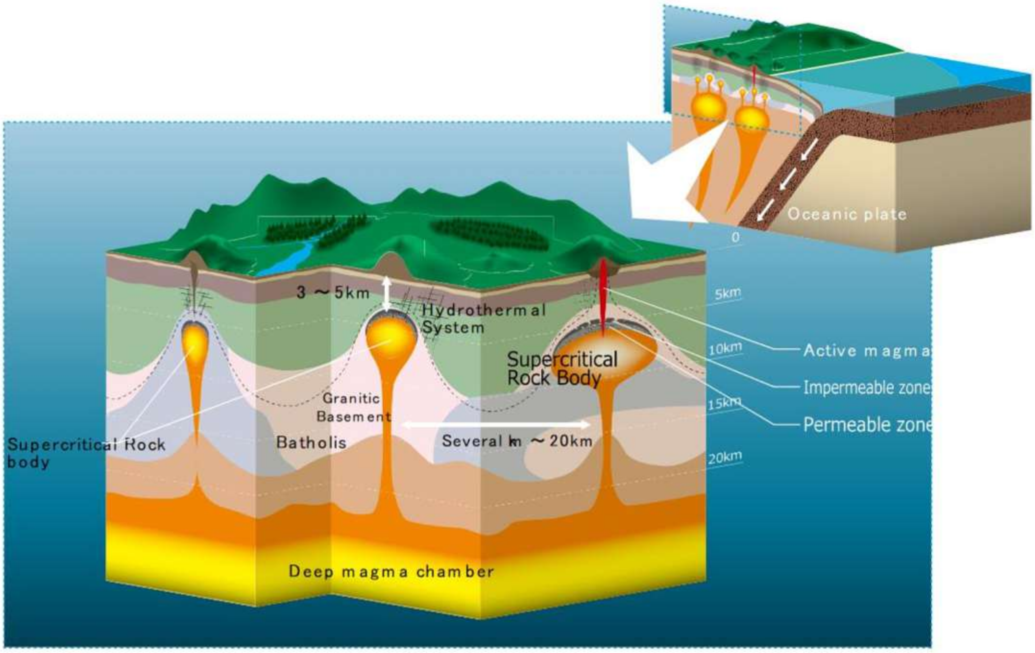

Figure 3.4: Conceptual model of the super critical geothermal system in northeast Japan (Source: Asanuma et al., 2021) - Supercritical Rocky Bodies are supposed to be in shallower depths in volcanic areas making it easier for access.

3.2.4 Conclusion on Geothermal Energy

Contrary to other renewable energy resources, namely solar and wind, geothermal is not affected by weather conditions. The integration of geothermal energy as an addition to the other resources would make the whole energy system more secure, since diversification of energy supply per se makes the system evidently less dependent on only one specific resource.

The benefits of deep reservoirs and geothermal energy in general should be clear, although the development and economical challenges have to be considered. Geothermal energy makes a safer base load energy compared to nuclear energy, since environmental worst-case scenarios like Chernobyl or Fukushima, affecting millions of people worldwide for decades, cannot occur. Additionally, future problems of new nuclear waste would also be eliminated. Although Japan sees nuclear power as a national self-sufficient energy form, because only little fuel is necessary, it actually is not, but geothermal on the other side is (Yoshida et al., 2018). Economically they are both very expensive technologies but due to completely different reasons. Development risks and the uncertain return of investments makes it difficult to find private investors for geothermal energy. Therefore, it is necessary for the government to make the right incentives regarding this energy resource. If national subsidies are flowing into the right technologies, geothermal energy production can be competitive. Together with hydro energy, it could replace nuclear power plants in long term. This will likely not happen in the near future. On one side, nuclear energy is still necessary for the low greenhouse gas emissions energy transition (ANRE, 2021c). On the other side and more fundamentally the use of nuclear power is also a subject of national security. Simply by using nuclear power it is possible to make nuclear weapons (Yoshida et al., 2018). This effects the strategical point of view for geothermal power plants, making it very hard to become one of the main resources. Unless there is no additional support or higher subsidies, the future of geothermal energy is uncertain. The potential of geothermal energy is summarized in Table 3.2. The capacity factor of geothermal energy in Japan ranged from 54.3% to 74.3% between 2000-2021 (IRENA, 2024b). The estimated electricity generation potential corresponds then to 111.6 TWh to 325.4 TWh.

potential range	theo. potential	c-factor	est. e-gen. potential
23.47 - 50 GW	50 GW	54.3 - 74.3%	111.6 - 325.4 TWh

Table 3.2: Geothermal energy potential in Japan. In 2022, only 437 MW of this huge potential was installed (IRENA, 2024b).

3.3 Bioenergy

Bioenergy has a long history in humankind and generally it is an energy form that derives from organic materials. The first use of bioenergy was certainly the "invention" of fire in the prehistoric paleolithic[11], when wood was used for heating or cooking purposes. From today's perspective, Bioenergy is an extensive topic. The original use of bioenergy was expanded by electricity or biofuel production. Additionally, the varieties of different organic materials increased tremendously and is called biomass. Although the origin of fossil fuels is also from organic materials, there is a clear distinction between biomass and fossil fuel. Bioenergy uses resources that can be replenished on a human timescale, and therefore it is listed as an renewable energy source. It includes, for instance, plants, human and animal waste, agricultural residues, crops, algae or even charcoal. Latter one is produced from wood through pyrolysis. Wood can regrow and hence charcoal is considered as biomass. The same applies to the plant-based coal (biochar). On the contrary, brown coal and bituminous (black) coal are fossil fuel resources as they are created in high pressure under the ground over million of years. Other fossil fuels are oil and natural gas (IEA, 2023b).

All organic materials contain carbon and therefore, fossil fuels can be regarded as carbon sinks or CO2 storage. However, the extraction and combustion of fossil fuel result in the release of a substantial amount of greenhouse gas emissions into the atmosphere. While biomass also generates emissions during combustion, it is typically considered CO2-neutral. This is because only the amount of CO2 that was originally absorbed by the organic material—such as through plant photosynthesis during growth—is subsequently released back into the atmosphere. If biomass production is effectively managed, the CO2 concentration in the atmosphere can potentially be reduced. This can be achieved by ensuring that the carbon sequestration during plant growth exceeds the emissions produced during biomass harvesting, processing, and combustion, resulting in a net reduction of atmospheric CO2.

3.3.1 Production of various Biomass End-Products such as Charcoal or Methane

Charcoal production through pyrolysis has been practiced since the bronze age, but the process has undergone significant advancements and refinements over time. Modern applications distinguish between pyrolysis and gasification, both of which involve

[11] also called the old stone age

heating organic material to high temperatures under controlled conditions. In pyrolysis, the process occurs in the complete absence of oxygen, whereas gasification is conducted with a limited and strictly regulated oxygen supply to prevent complete combustion. The choice of process depends on the desired end products. Pyrolysis is primarily employed for the production of solid and liquid materials such as biochar, charcoal or bio oil. In contrast, gasification is utilized to produce synthesis gas, a gaseous mixture predominantly composed of hydrogen, carbon monoxide, and smaller fractions of methane. Synthetic gas is typically further processed in subsequent stages to produce more valuable or usable products, such as methane (via methanation), liquid fuels (through Fischer-Tropsch synthesis), or various chemicals (Zahoransky and Allelein, 2015).

Another method to produce methane is by biological degradation. This process, known as anaerobic fermentation, occurs naturally within the digestive systems of ruminants like cattle, goats or horses. Especially the livestock of cattle produce tremendous amounts of methane emission. Since methane has an global warming potential (GWP) that is 81.2 times greater than that of CO2 over 20 years (Smith et al., 2021), cattle livestock has an significant impact on the greenhouse gas emissions. Compared to 1961, the global cattle population has increased by 67% from 942 to 1576 million by 2023. Other significant ruminants are goats (1127 million), sheeps (1324 million) and buffaloes (209 million) living animals in 2023. Their numbers increased by 223%, 33% and 137% since 1961, respectively (FAO, 2024). This becomes an increasing issue and researches for solutions like feeding manipulation to mitigate enteric methane emissions are being conducted (Tseten et al., 2022).

3.3.2 Reducing the Environmental Impact of Livestock Manure

Although methane emissions from flatulence and eructation are unavoidable, emissions from livestock manure can be mitigated through the capture of gases in anaerobic digestion plants (biogas plants). These digesters harness the same anaerobic fermentation process that occurs in the digestive systems of ruminants. Bacteria responsible in this process are still active in the manure after defecation and the liquid manure keeps releasing methane. By collecting the manure and directing it into anaerobic digesters, the gas generated during fermentation can be captured and utilized as an renewable energy source. The produced gas by this method is called biogas and typically consists of 60-65% methane, 35-40% CO2 and other gases. In addition to liquid manure, agricultural residues, food waste, and wastewater (including sewage sludge) can also be utilized as feedstock for this process. The principle of this process is straightforward and is commonly implemented in developing countries. The biogas can also be upgraded to natural gas quality, referred to as biomethane or renewable natural gas, which can subsequently be injected into the gas distribution network or utilized as a vehicle fuel (Tauseef et al., 2013; Grubert, 2020).

In Japan, the only significant ruminant livestock is cattle. The numbers of cattle peaked at 5.02 million in 1993 and decreased since then by nearly 20% to 4.04 million in 2023 (FAO, 2024). Despite the downward trend in cattle population contributes to reducing greenhouse gas emissions, the utilization of biogas plants in Japan remains limited. In Hokkaido, which is home to approximately half of Japan's cattle population, only 40 centralized biogas plants are operational. In 2013, manure from just about 1% of all cattle was treated in biogas plants due to the high total costs compared to the low price of renewable electricity. The largest expenditure is attributed to transportation costs of manure and digested slurry between the agricultural communities and the power plants (Yabe, 2013). However, due to the "Act on the Proper Management and Promotion of Use of Livestock Manure (Act No. 112 of 1999)" farmers are required to ensure proper manure treatment to prevent pollution to the environment (Ministry of Justice, 2011).

3.3.3 Unintended Negative Consequences of Bioenergy

While bioenergy is considered a renewable energy resource, both the technology and the use of biomass should be approached with caution. Bioenergy is susceptible to green-washing and may lead to negative consequences that could outweigh its perceived benefits. Regarding the previously discussed renewable natural gas (RNG) derived from waste, there is a potential risk that poorly designed incentive structures could promote the production of biomethane from intentionally generated waste, rather than from authentic waste sources. Nevertheless, renewable natural gas remains a more sustainable option compared to fossil natural gas (FNG), as its emission impact is significantly lower, making it a viable solution for non-electricity applications (Grubert, 2020).

Another deriving issue by the expanding global biomass demand could be the deforestation. Regarding that issue two major factors could lead to an overall deforestation. One is that wood harvesting exceeds plant growth rate, especially if reforestation efforts are absent or insufficient. The second factor is that an tremendous amount of forest areas could be cleared in order to cultivate biomass, reducing the globally available forest areas (Raven, 2021). This could also lead to the exploitation of inexpensive biomass imports from economically less developed countries, and subsequently greenwashing the own decarbonization efforts. For instance, South Korea and Japan imported 68,000 and 52,700 tonnes of wood pellets from Indonesia in 2023, respectively (Milko, 2024). However, this accounts for only about 1.2% of the 4.4 million metric tonnes of wood pellet imports into Japan. The primary import sources for wood pellets are Vietnam (54%), Canada (31%) and the United States of America (7%) (Sasatani, 2023).

In the climate debate, many scientist argue that the oversimplified perspective of achieving carbon neutrality by burning trees instead of fossil fuel is not a viable solution for decarbonization. This approach may only increase global warming over the course of decades to centuries. The impact of carbon emissions from wood burning is estimated to be two to three times greater than that of using fossil fuels combustion. While carbon is released immediately upon combustion, the regrowth of forest takes decades, producing a so called "carbon debt", that lasts for several decades to a century. Notably, sustainable forest management practices cannot alter these outcomes. Although in the long term, when the debt is repaid and the benefits of bioenergy are realized, the use of bioenergy leads to higher atmospheric CO2 levels before break-even. This intensifies climate change and may cause potentially irreversible impacts that arise before the long-run benefits are achieved. Consequently, the urgent climate goals for 2050 require other solutions to prevent worsening climate change (Raven, 2021; Sterman, Siegel, and Rooney-Varga, 2018).

In summary, bioenergy has the potential to mitigate greenhouse gas emissions, albeit with the challenge of potentially increasing other environmental impacts such as toxicity, soil acidification and water eutrophication (Balcioglu, Jeswani, and Azapagic, 2023). Furthermore, bioenergy offers diverse applications across various sectors. While its primary use has traditionally been in heating, its role in electricity generation is increasingly gaining significance.

3.3.4 Bioenergy in Japan

In 2021, bioenergy remained Japan's dominant renewable energy source, accounting for 60% of renewable energy consumption (excluding electricity) (IRENA, 2024a). The remaining 40% was consumed as electricity. In the renewable electricity generation, which had a share of about 20% in the total electricity generation, bioenergy ranked third in 2021 and contributed 16% or 34 TWh right after solar power (41%, 86 TWh) and hydropower (37%, 79 TWh). Wind and geothermal energy together represented only 5% or 12 TWh. The electricity generation by bioenergy increased significantly with the FiT introduction in 2012. The installed capacity rose from 893 MW to 5805 MW (an increase by 650%) between 2012-2023 (IRENA, 2024b). In the total electricity generation, the target for bioenergy in 2030 is 5% or 46.7 TWh of the anticipated 934 TWh (ANRE, 2023a).

3.3.5 Bioenergy Potential in Japan

In a previous study conducted in 2005, the bioenergy potential from livestock residues in Japan was estimated at 167 PJ for the year 2000 (Fujino et al., 2005). These residues, originating from cattle, swine, laying hens, and broilers, accounted for 22% of industrial waste. The residue from cattle and swine are used as input for biogas production through methane fermentation, which is subsequently utilized in cogeneration systems[12]. In contrast, poultry residues are dried using floor heating systems and directly burned in the cogeneration system, consisting of a boiler and steam turbine generator. Of the steam produced, 35% is used for electricity generation[13]. Considering the conversion and efficiency losses, the total livestock residues were estimated to generate 4.1 TWh of electricity and 46 PJ of heat. Given that these values are based on data from 2000, the most recent values for livestock in Japan from 2022 have been used from the ministry of agriculture, forestry and fishery (MAFF, 2024), and the current bioenergy potential from livestock has been re-evaluated using the same methodology. Currently, the livestock residue has a potential of 156 PJ and can contribute to a estimated 3.8 TWh of electricity and 44.8 PJ of heat. It should be noted that future livestock could further diminish due to the population decline, which finally decreases the demand for livestock.

A recent and more comprehensive study assessed the overall bioenergy potential of various feedstocks and their projected changes in Japan throughout the 21st century (ANRE, 2023a). This study considered factors such as population change, land use and biophysical conditions and used an integrated assessment framework model. Additionally, the costs of the individual feedstocks were estimated as well. The study projects a total technical bioenergy potential to range between 3.43 to 3.78 EJ[14] per year over the course of the century. The assessed feedstocks and their potentials for the years 2050 and 2100 are summarized in Appendix Table A1. Most of the feedstocks consist of either residues or byproducts, which are unavoidable waste streams. However, the use of surplus wood and bioenergy crops remains a controversial, particularly concerning their potential to enforce the negative environmental impacts of bioenergy production. Surplus wood is defined as the forest growth that is not allocated for round-wood production. This implies that utilizing this feedstock allows the total forest area to remain constant, if other factors are excluded. The feedstock from bioenergy crops can be further divided into two groups: cropland originating from light forest & grassland, and cropland from abandoned agricultural lands. Both groups could contribute to deforestation. While the first group directly involves deforestation, the second group might indirectly originate from it. Globally, the rising population

[12]power generation efficiency η_{el} = 25%, thermal efficiency η_{th} = 45% (Fujino et al., 2005)
[13]Boiler efficiency: 85%, steam turbine generator efficiency: 15% (Fujino et al., 2005)
[14]primary energy

and the limited availability of cropland could lead to clearing forests for new agricultural fields. However, the current situation in Japan is contrary to the global trend. The population decline reduces food consumption, waste and livestock. Subsequently all feedstock deriving from these sources will diminish over the time. Especially, agricultural cropland is increasingly abandoned and becomes available for bioenergy crop cultivation. The study's model projects an increase of 23,600 km^2 in available farmland for bioenergy crops until 2050 compared to 2005. Although this additional land could be utilized for solar or wind energy, diverting farmland — whether cultivated or abandoned — is strictly prohibited to maintain food self-sufficiency (Obane, Nagai, and Asano, 2020; ANRE, 2023a). In this thesis the potential of bioenergy crops for light forest & grassland as well as surplus wood will be deliberately excluded.

3.3.6 Conclusion on Bioenergy in Japan

The present global trend toward increased bioenergy reflects the shortsightedness of political decisions driven by an oversimplified evaluation of its benefits. Especially, the reliance on natural gas derived from waste (such as biomethane from anaerobic digestion) could impede the transition to more environmentally friendly systems and subsequently delay climate mitigation (Grubert, 2020). To ensure that the negative effects of bioenergy do not outweigh its positive contributions, stringent international laws and regulations are urgently required, particularly to prevent deforestation and mitigate other emissions. This thesis therefore exclusively considers bioenergy potential from unavoidable waste streams and residues, thereby ensuring that the analyzed pathways do not contribute to land-use change or deforestation. To finish this chapter, the potential of bioenergy in Japan is summarized in Table 3.3. If this potential is used in cogeneration with a power generation efficiency η_{el} of 25% and a thermal efficiency η_{th} of 45% is assumed, then the it could contribute to 197 TWh of electricity and 1276 PJ of heat.

feedstock	PJ	power gen. in TWh	heat in PJ
Bio crops (abandoned cropland)	1140	79.2	513
Agricultural residues	680	47.2	306
Municipal waste	470	32.6	211.5
Black liquor	260	18.1	117
Livestock residues	156	10.8	70.2
Forestry residues	130	9.0	58.5
Total	2836	196.9	1276.2

Table 3.3: Bioenergy potential in Japan in cogeneration (η_{el} = 25% and η_{th} = 45%)

3.4 Solar Photovoltaic Energy

Solar energy in Japan goes back to the 70s, where the government called for the "Sunshine Project" in response to the oil crisis in 1973. The support was decided to 500 billion yen between 1973-2000 (Watanabe, 2021). This project marked only the beginning to many other programs like the "sunlight" in 1974, "moonlight" in 1978 or the "new sunshine" in 1993 to support renewable sources in general as an alternative to oil but focused mainly on solar energy (Lecler and Brombal, 2017).

3.4.1 History of Solar Photovoltaic Energy in Japan

Until 1992 programs were dedicated to research and development programs. The first program toward utility and consumers was then introduced, where the EPCOs could - but were not obliged to - purchase surplus electricity from photovoltaic installations at the exact same rate as the retail electricity price. It was called the net billing program. After a grid connection guideline for solar photovoltaic was implemented in 1993, a subsidy scheme for residential installations of photovoltaic was introduced in 1994 and existed until 2005. In these eleven years more than 250,000 installations and a capacity of over 930 MW were funded. As a result of this the average installation cost dropped from 1.920 million yen to about a third to 661 thousand yen in this period. With the end of this scheme in 2005 the annual installation rate declined (see Figure 3.5), although the government introduced additionally the Renewable Portfolio Standard (RPS) in 2003, where utility companies were obliged to generate a specific percentage of the electricity from renewable sources. It was originally planned to introduce a FiT. However, due to lobbying of the EPCOs, the RPS system with a relatively low target was implemented instead (Watanabe, 2021; Muhammad-Sukki et al., 2014). This RPS target was set to 12.2 TWh for FY2010 and later revised to 13.43 TWh for FY2014. These relatively low goals were exceeded by the EPCOs without a significant economic burden to them (Ito, 2015). However, as it became clear that the governmental second target of achieving 1.35% of the national electricity from renewable resources by 2010 would probably not be met, the government not only reinstalled the subsidy scheme, but also introduced a FiT solely for solar photovoltaic in 2009 and successfully increased the installed capacity to 4.9 GW by 2011. More than 90% of the installations came from residential buildings (Muhammad-Sukki et al., 2014). Nevertheless, the actual electricity supply from solar energy (renewable resources in general) remained significantly low. In 2010 the renewable energy share still contributed only 1.2% to the total electricity supply, because the focus of the government was to rely on nuclear energy as a substitution for fossil-fuel. Subsequently, a regulatory structure to prioritize renewable energy was missing (Lecler and Brombal, 2017; Watanabe, 2021; Muhammad-Sukki et al., 2014).

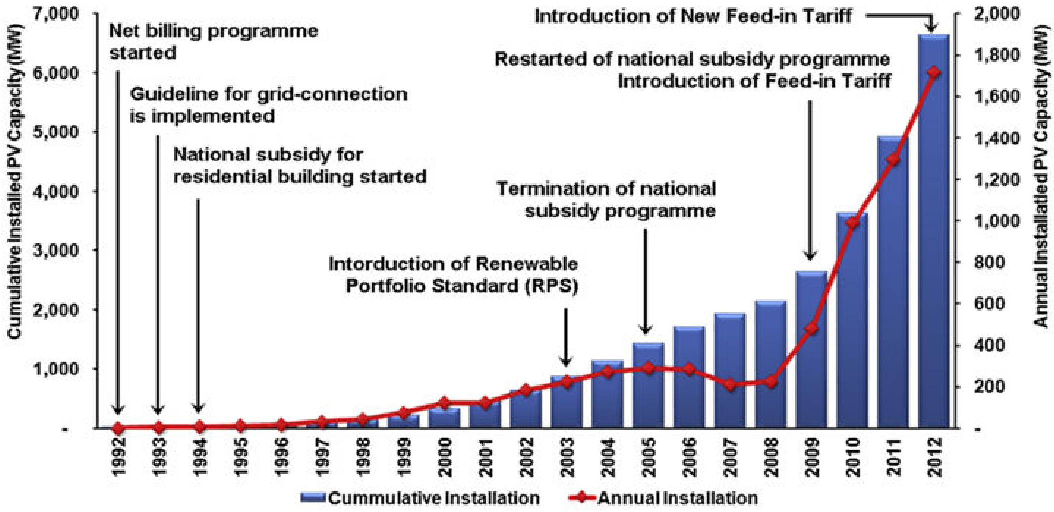

Figure 3.5: The progress of solar photovolatic installations in Japan between 1992-2012 (Source: Muhammad-Sukki et al., 2014)

While the total generation share might not have increased significantly, Japan's constant support for solar energy made the country a world-leader not only in the development but also in production and the installed photovoltaic as well. It was only overtaken in the mid-2000s when the government ended the subsidy scheme between 2005-2009 to search for better solutions (with higher volumes). Germany became leader in installed capacity and generation, while China surpassed Japan in production and exports (Lecler and Brombal, 2017; Watanabe, 2021; Muhammad-Sukki et al., 2014).

3.4.2 The Consequences of the Fukushima Nuclear Accident on Solar Energy

It was only after the Fukushima incident that the main strategy for renewable energy underwent a dramatic reform. The scale of the renewable energy share goal in the energy mix increased significantly to a target of 20-35% by 2030. The RPS, which was originally only introduced because of the influence of the EPCOs, was abolished, and instead a new full-scale FiT scheme was introduced in July 2012, which enhanced the former partial FiT for solar in 2009. The new and still active scheme includes the other renewable energies wind, geothermal, hydro and biomass. In contrast to the former

FiT, where only excessive solar generation was fed into the grid (meaning its purpose was mainly for self-sufficiency), the new one mainly addressed the non-residential, the commercial and industrial sector, when it comes to the solar tariffs. In general, the solar tariffs were set comparably high to that of other nations. For example, the tariff in Germany, Italy and UK was only half as much as in Japan and in China it was only a third to that of Japan. Although almost 85% of the total installed capacity for solar power came from residential buildings before the introduction of the FiT in 2012 this changed quickly after (Muneer, Jadraque Gago, and Etxebarria Berrizbeitia, 2022), as the government refocused on utility scale solar power plants. After just six months an additional 1.7 *GW* of solar photovoltaic were installed, an increase of 33% to the previous year. The non-residential share of the total cumulative installed 6.6 *GW* for solar photovoltaic quickly grew from 15% to 30% in this short period (see Figure 3.6). Some of these projects even started operation by the end of the year (Muhammad-Sukki et al., 2014; IRENA, 2021).

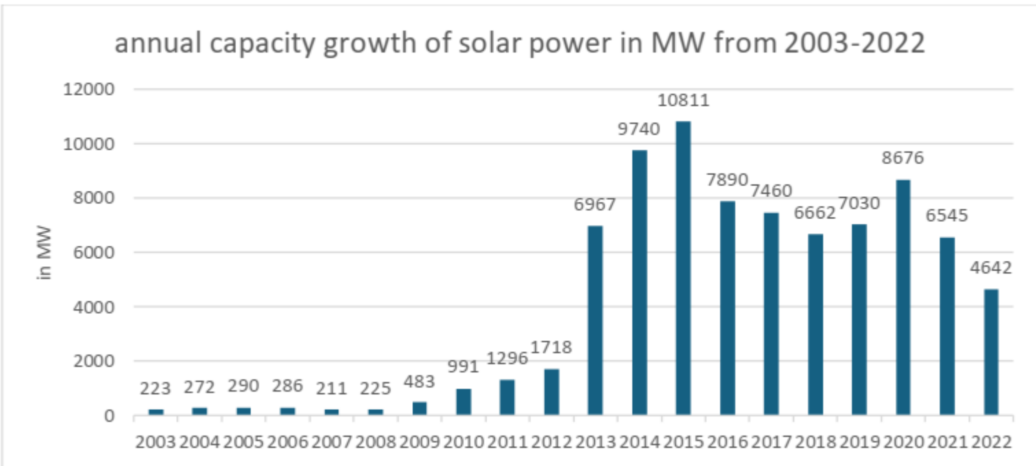

Figure 3.6: The effects on the installation rate of solar photovoltaic energy after the new FiT was introduced in 2012 (based on: IRENA, 2024b)

The more ambitious efforts for renewable energy (especially for solar energy) by the government showed its effect. While the overall annual growth rate for renewable energy in capacity under the RPS system was approximately five percent between 2003 to 2008, it grew to nine percent in 2009-2012 after the introduction of the partial FiT (for PV solely). These growth rates in renewable energy were accomplished before the new renewable energy share targets of 20-35% in electricity generation by 2030 were set. After that, the expansion of renewable energy exploded to 32% in the first year[15]. The mean annual growth for the overall renewable energy in capacity between 2012-2021 is 16% (Yoshida et al., 2018; ANRE, 2023a).

3.4.3 The Flaws of the Feed in Tariff

However, several years after the introduction of the new FiT in 2012 it became clear that most of the renewable energy installations came mainly from solar energy. This was due to the imbalanced high solar tariffs among the renewable energy and to the long environmental impact assessments processes for certain other than solar technologies. To encourage further the other renewable energy technologies the FiT was revised in 2017 (Wu et al., 2020). While annually dropping the FiT for solar photovoltaic, the long lead times for other renewable energies like wind power, bioenergy, geothermal and small-scale hydropower are now covered by a multi-year FiT to provide higher certainty for developers. Additionally, a FiT for offshore wind energy was introduced as well. There were several other reasons for the revision, like the flaws of the design of the FiT. Many projects were registered under the FiT, but producers were not obliged to have positive negotiation for interconnection with the grid utilities (the EPCOs) for registration. It was possible that projects faced rejection for grid connection. As a consequence, many projects were never realized, and subsequently these registered projects created fictive values in installation capacity and therefore would falsify the real installed capacity in statistics. Thus, a more reliable statement can be made by looking at the generated energy. For instance, in 2016, renewable energy (excluding pumped hydropower) contributed 227 TWh, while coal and natural gas generated 295 TWh and 402 TWh, respectively (Yoshida et al., 2018). Since the revision of the FiT in 2017, new projects would now require to have positive negotiations with the grid utilities first before actually getting registered. An additional problem was, that there was also no time limit set for the construction phase. The nature of a FiT is to encourage investment by providing a rate of return. It is reviewed and decreased on a yearly basis, depending on the falling costs. However, since the amount of the guaranteed tariff is determined by date of registrations, many projects were delayed in hope of falling costs, while benefiting from a secured higher, older tariff and therefore maximizing the profit. In order to stop such delays, a time limit has been adopted (Malala, 2022). Projects must now start operation after a certain amount of time after they have been registered. Otherwise, they face suspension and losing all rights to incentives. This also applies to all the older projects, that have been registered before the revision. Those projects now have been granted a grace period (Yoshida et al., 2018).

[15]It was mainly due to the earlier mentioned growth of 33% solely in solar photovoltaic

These two major design flaws, namely the registration before negotiation with the grid utility and the missing time frame, would cause that more than half of the approved projects in the year 2012 (23%), 2013 (49%) and 2014 (59%) were not implemented by the end of 2018. The remaining not suspended projects would now only be granted a newer, reduced FiT support of 21 yen/kWh or less, instead of the initial tariff (IRENA, 2021).

3.4.4 Curtailments and the Introduction of the Priority Dispatch Rule

By the end of fiscal year (FY) 2017 the installed capacity for solar photovoltaic increased to 44.5 GW. A resulting issue from these rapidly growing solar projects under the FiT was the missing demand within some utility service areas. One of the regions, where the supply of the projects exceeded the load, was in the southern island Kyushu. Thus, Kyushu Electric began refusing further interconnections to the grid in 2015 within its service area. The government began as a response to calculate the theoretical possible capacities for renewable energy in the individual regions in order to maximize the share of renewable energy in the power generation. It should be noted that two nuclear reactors began operation in 2015 in Kyushu and another two in 2018. By September 2018 all four of Kyushu's nuclear reactors with a cumulative power of nearly 4 GW re-operated fully again. In October 2018 Kyushu Electric began curtailing solar photovoltaic[16] on a frequently basis after that. The response by the government[17] was the implementation of curtailment rules. This priority dispatch rule (see Figure 3.7) requires the electric producers, first to reduce the output of thermal power plants and filling up the pumped hydroelectric energy storage in the affected area. Secondly, if this is not sufficient, the interconnection has to be used to supply the adjacent region and thirdly bioenergy power plants have to be curtailed. Only then curtailment of solar photovoltaic and wind is to be applied. At last, base-load power plants with low CO2 emissions like nuclear, geothermal and hydro power plants would be curtailed, as they are slow in adjusting and build the foundation of the energy supply (Ichimura, 2020; World Nuclear Association, 2024b; Yoshida et al., 2018).

3.4.5 The Oligopoly Problem

The current policy of prioritizing grid stability over the expansion of low carbon technologies by the government gives basically the EPCOs the power of judgment to grid connection. Together with the policy to restart the nuclear fleet many other regions will

[16] and also wind power

[17] More precisely, it was introduced by the Organization for Cross-regional Coordination of Transmission Operators (OCCTO)

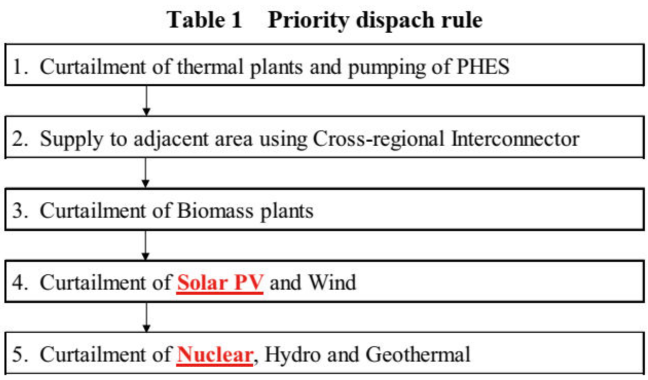

Figure 3.7: Dispatch Rule by OCCTO (Source: Ichimura, 2020)

be confronted with the same problem as in Kyushu. Volatile technologies like solar and wind energy will face curtailments or even worse with rejection to power grid connection by the EPCOs. As a consequence, this could lead increasingly to a stagnation of the introduction of renewable energy. Currently (January 2024) twelve nuclear reactors with a total power over 11 GW are back online. All of these active reactors are located in the south and western half of Japan (World Nuclear Association, 2024b). While it could be a wise decision to restart nuclear reactors directly connected to high demand centers like in the Tokyo Metropolitan area, remote locations with abundant renewable resources like Hokkaido in the north would easily be satisfied by the nuclear power supply, leaving no room for expansion of renewable energy. The situation is stricter in Hokkaido than in Kyushu, as the demand and population density is far smaller. Unless there are inter-regional connection lines to transport excessive power to the south, harsh connection constraints and curtailments would be inevitably. However, there are already plans to connect Hokkaido directly with the greater area of Tokyo (OCCTO, 2022b). Indeed, after the beginning of the restart of nuclear reactors in 2015 the annual increase of solar energy dropped significantly, but fortunately did not stagnate yet (see Figure 3.6). This might have been prevented due to the major structural changes in the electricity grid, namely the deregulation since 2015, the tremendously increased efforts toward the decarbonization of the electricity grid, as well as the dispatch rule. Nevertheless, the Feed in Tariff has been a great success for solar photovoltaic energy, as by 2019 Japan was not only placed second in the world for installed solar capacity, but primarily placed third in solar energy generation. Between 2010-2019, Japan managed to rise its solar generation from 0.3% to 6% in the total electricity generation mix (IRENA, 2021).

3.4.6 Surcharges, the Auction Scheme and the Feed in Premium System

Future cornerstones to prevent a full stagnation of the growing share of renewable energy in the power mix especially for solar and wind will be the expansion and managing of inter-regional transmission lines, as well as the allocation of upgrading costs. Last but not least to reduce the rising burden of the FiT on household electricity costs. Latter one is presently an increasing problem, since the FiT system guarantees a producer of renewable energy a fixed margin for selling electricity into the market, regardless of time, date and ignoring actual demand or supply. The customer is in this particular case the individual grid operator, the concerning EPCO. However, this financial burden is directly forwarded to the end consumer by applying collectively a surcharge in the electricity bill. While the great success of the solar expansion is considerably contributed to the attractive FiT rates, this surcharge grew between 2012-2020 from an average 57 yen to 774 yen per month, an increase by 1360% (Yoshida et al., 2018; Malala, 2022)[18].

To lower the burden a different approach was tried with the revision in 2017 by adopting an auction scheme for renewable energy. Additionally, to yearly lowering the feed in tariffs, the eligibility criteria for the FiT were adjusted as well. Concretely speaking, in the case for the solar energy, project sizes were limited to less than 2 *MW* in 2017 and 2018 to be eligible under the FiT. This limit was even lowered to 500 *kW* and 250 *kW* in 2019 and 2020, respectively. Projects that exceed the criteria have to enter an auction process. The first auction for solar energy was held in November 2017. The idea of the auction is simple. Participants underbid each other in order to gain access to funds provided by the FiT. The lowest bid wins the auction and gets the approval to build their power plant. Until October 2020 five auction for solar energy had been conducted and managed successfully to cut prices by over 35%. However, from the announced volumes of 1,663 *MW* only about a third of 574 *MW* have been awarded. Many bidders dropped out, because of losing interest due to constraints regarding grid connections or land availability connected with high risks or penalties through commitment bonds and tight deadlines. While participation restriction requirements were set low, Japan's auction system has with two commitment bonds very strict compliance rules. Participants have to pay a bid bond of 500 yen/*kW* to ensure contract signing and a ten times higher completion bond of 5000 yen/*kW* to ensure project implementation. Auction winners of the first round had only two weeks to submit the completion bonds, three months to obtain governmental certification after being awarded and an additional month to settle for a grid connection agreement. This caused five awarded projects to drop out before even paying the commitment bond in fear that this deadline could not be kept, and the deposited bond would be confiscated. The result was that only 41

[18]In contrast to a subvention by the government, which is indirectly already paid through taxes, the FiT is putting an additional burden/tax to the customer.

MW out of 141 *MW* initially awarded was being contracted in the first auction. The government relaxed the confiscations rules in the next rounds in response to the developer's feedback. The commitment bond could now be carried into the next auction if governmental certification is not procured within the deadline and the developers deposit is also not confiscated if external factors failed them to deliver. In order to attract smaller and local players, local public projects funded by the local government as well as projects promoting a revitalization of rural areas were exempted by the financial burden of the commitment bonds in the fourth and fifth round (IRENA, 2021; Yoshida et al., 2018).

3.4.7 The Introduction of the Feed in Premium System

The auction may have an impact in slowing down the increase of the burden to the household's electricity cost, but it does not stop or prevent it. Presently, this surcharge is yet mostly a result of the solar energy alone. If offshore wind power will advance in the future, it is clear that this surcharge increase cannot go on indefinitely. However, more importantly is the major design flaw of the FiT as it ignores completely the market, or more precisely the supply and demand, making the energy grid more and more unstable (Yoshida et al., 2018). The isolation from the market also hinders innovation through competition (Malala, 2022). The government therefore announced in 2020 a Feed in Premium (FiP) and started it in FY 2022 to tackle these problems (IRENA, 2021; AHK Japan, 2022).

The FiP system forces renewable energy producers to consider the supply-demand as the revenue is coupled to the price of electricity at the energy exchange market and includes an additional "premium" (see Figure 3.8). This means that high profits can only be achieved when also the prices in the market are high, which is usually when demand is high but supply low. With the FiP, it is expected to reduce the costs for the entire system, enforce the expansion of renewable energy and should give producers, a motivation to feed their electricity into the grid when market prices are high in order to maximize their profits (Malala, 2022). This could be achieved by preserving energy in batteries or other forms of energy, which will make the electricity grid more stable (ANRE, 2021b).

3.4.8 Potential of Solar Photovoltaic Energy

The potential of solar power can be divided into two groups. One is the potential on open land and the second is the potential on buildings. Both of them have different limitations or restrictions. In case of building mounted solar system the potential of all

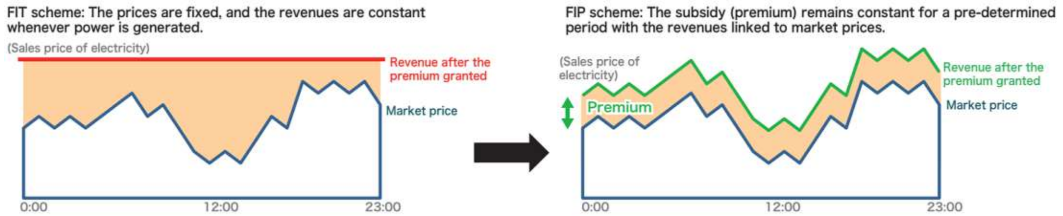

Figure 3.8: Comparison of Feed in Tariff and Feed in Premium (Source: ANRE, 2021a)

roof-mounted and wall-mounted solar systems is around 292 *GW* (Obane, Nagai, and Asano, 2020). The potential of buildings can be further split up into the solar systems built on public or corporate buildings and residential buildings. If in the residential sector apartment buildings are neglected and only detached houses are equipped with solar panels this could contribute between 94–118 *GW*[19] alone (Shimoda et al., 2021). Since the subject of the solar photovoltaic potential on buildings require additional research and would go beyond the scope of this thesis, it will therefore only discuss the potentials of solar photovoltaic on open land in more detail. This however will be discussed in the next chapter 3.5 with the wind technology as both technologies are in direct competition when it comes to land-use. A short summary about the solar potentials will be given in Table 3.4. The stated estimated electricity generation potential is derived from the installed capacity and the capacity factor range for solar energy in Japan between the period 2000-2021 (IRENA, 2024b).

3.4.9 Conclusion on Solar Photovoltaic Energy in Japan

Historically, solar photovoltaic (PV) energy has received the most attention among renewable energy sources in Japan. This is primarily due to its simple installation and strong government support. However, as policies shifted support toward other technologies, along with the introduction of environmental impact assessments for solar energy projects, the growth has been decelerated. Despite this, solar PV has remained to expand at a relatively high rate compared to other renewable energy sources.

A key factor influencing future expansion is the restriction on grid integration imposed by electric power companies (EPCOs). It remains uncertain how these limitations will impact growth. Consequently, battery storage is becoming increasingly

[19] depending of the installed capacity per household. Assumptions are 4-5 *kW*/household, respectively.

necessary. While this could enhance self-sufficiency, it also affects the economic viability of solar PV systems with integrated storage. Nevertheless, Japan continues to have substantial potential for further solar PV expansion. As shown in Table 3.4, the total potential for solar photovoltaic energy in Japan exceeds 500 *GW*.

	pot. range	theo. pot	c-factor	est. e-gen. pot.
Solar (land)[20]	64 - 230 *GW*	230 *GW*	10.8 - 13.8%	60.5 - 278 *TWh*
Solar (all buildings)	0 - 292 *GW*	292 *GW*	10.8 - 13.8%	276 - 334 *TWh*
Solar (detached houses)	94 - 118 *GW*	118 *GW*	10.8 - 13.8%	89 - 135 *TWh*

Table 3.4: Solar photovoltaic energy potential in Japan

[20] The solar potential on land will be discussed in more detail in the next Chapter 3.5

3.5 Wind Energy

After the oil crisis, wind was not among the technologies that was supported as other technologies like solar, geothermal, coal and hydrogen through the sunshine program. Nevertheless, marginal wind energy support began already in 1978 and the installed capacity reached 17 *MW* by 1997. The first substantial growth came one year later in 1998, when capital subsidies were introduced. The capacity grew rapidly to 339 *MW* until 2002. When in 2003 additionally the RPS came into act, the capacity growth achieved a stable rate of around 250 *MW* annually until 2010. However, the capital subsidies ended in 2010 and the growth rate dropped immediately to a third in 2012. By 2012 the cumulative installed capacity reached 2614 *MW* (Mizuno, 2014).

3.5.1 The Obstacles to the Introduction of Wind Energy in Japan

A shift in the government's focus on wind energy can be seen in the roadmaps of the METI between 2007 - 2009. Wind energy was acknowledged as one promising future renewable technology. Governmental support especially for research, development and demonstration increased remarkably (Mizuno, 2014)[21]. However, the change from the RPS to FiT in 2012 did not have great effects on the installation rate. Until 2022 the cumulative installed capacity was 4372 *MW*, that corresponds to an annual increase of about 165 *MW* between 2012-2022. Most of the installed capacity is built onshore, while offshore is except for a few pilot projects still not existing (IRENA, 2024b). Considering that wind turbine sizes got bigger, higher installation rates should have been even easier to achieve than in the previous decade. Although the government enforced the targets for wind energy, they also implemented more than 50 laws, regulations, restrictions, guidelines and operational rules, which hindered the expansion of wind energy tremendously. One of the major reasons could be the complex environmental impact assessment (EIA) process for wind energy, which was introduced in October 2012 (Mizuno, 2014). This process prolonged the lead time of three to four years by another two or three years. In total it could take up to six years until a project is approved by the government (Mizuno, 2014). For offshore wind farms there were even more barriers until 2019, that made development preposterous. "*In 2019, a new law took effect, allowing permits which authorize offshore farms to run for up to 30 years. Before this law, project permits could only be given out for up to five years, which hindered the investment in offshore wind in Japan.*" (Bardenhagen and Nakata, 2020). Before 2019, permit extensions were required every three to five years (IRENA, 2021).

[21]These included researches for 1)solutions for the harsh Japanese weather and climate conditions, like lightening and typhoons, 2)large-scale offshore wind system development, as well as 3) grid stabilization technologies, like storage and power control system development.

As expected companies would not invest in a full-scale offshore wind farm, when the life expectancy of wind turbine exceeds these five years permits (Sheldrick, 2020). Investments are only plausible for research and development projects in case, law and situation would change in the future, which is validated by the projects of the last two decades. The first fixed-bottom[22] offshore wind project started already in 2003, and yet until 2021 there was less than 100 *MW* cumulative installed capacity in Japan, of which all of them are only pilot projects to gain know how (Bardenhagen and Nakata, 2020; GWEC, 2021; JWPA, 2022).

Even after passing all mentioned criteria, there is still the negotiation with the designated EPCOs about grid connection. These monopolistic companies were great barriers[23]. In the past they often either rejected or imposed unjustified grid cost connection or curtailments up to 8% of the producers income (Mizuno, 2014).

3.5.2 Influence of the Revision of the National Strategic Energy Plan on Wind Energy

In 2020 the government enforced its greenhouse gas emissions reduction from 80% to 100%. This revised plan for carbon neutrality changed the approach to wind energy. In former strategic plans for 2050 wind energy was mentioned, but generation was predicted to be from either solar or geothermal energy (Hirai et al., 2016, METI, 2021b). The higher greenhouse gas reduction targets forced Japan to rethink and rely more on its great potentials of offshore wind energy. The government aimed a target of 10 *GW* by 2030 and 30 - 45 *GW* by 2040 (METI, 2020). The Japanese Wind Power Association (JWPA) has even significantly higher targets to achieve a total of 140 *GW* in installed wind power capacity by 2050. Their targets are 40 *GW* for fixed-bottom offshore, 60 *GW* for floating offshore and additionally 40 *GW* for onshore wind power (JWPA, 2023). In order to reach their targets, the Japanese government planned to introduce promotion zones to accelerate the expansion of wind but also for solar energy based on the amended "Act on Promotion of Global Warming Countermeasures" and especially for offshore projects based on the "Act on Promoting the Utilization of Sea Areas for the Development of Marine renewable Energy Power Generation Facilities" (ANRE, 2021c). In short, several designated promotion zones with a cumulative generation capacity of 1 *GW* have been introduced with the beginning of 2020 on a yearly basis, where developers can win access to built farms in those zones by bidding in tenders. The government wants to reach the 10 *GW* offshore wind target by 2030 by

[22]Wind turbines that are seabed-mounted. The other technology the floating wind turbines, float like a buoy and is anchored to the sea-bed only by ropes.

[23]they still are today even after deregulation, although the deregulation and few laws and governmental support made the situation better

these tenders. The further introductions targets by 2040 is expected to be reached by reducing the costs of floating wind turbines through technology development and mass production (METI, 2020).

Even with some big-scale projects in the development, the 10 *GW* offshore wind energy target by 2030 is from the present perspective extraordinarily enthusiastic. However, according to the JWPA the 10 *GW* target of the government is only required legally for project approval and does not have to be attained through operation. The government expects 5.7 *GW* to be in operation by 2030 (JWPA, 2022).

3.5.3 Offshore Wind Energy in Japan

Despite the determination for increasing the offshore wind energy in Japan, the cumulative installed capacity for wind energy of 5213 *MW* at end of 2023 is nearly depended by onshore wind. Only 2.9% (154 *MW*) comes from offshore wind energy. Most of these 154 *MW* comes from fixed-bottom offshore wind energy. Only two wind turbines with a cumulative capacity of 5 *MW* of the offshore wind power is contributed by the new technology of floating offshore wind turbines (JWPA, 2024). Compared to Europe (including the United Kingdom) with 30 *GW* or China with 30.5 *GW* for installed offshore wind capacity at the end of 2022, Japans offshore wind capacity is close to zero. Except for a few pilot projects there were no offshore wind parks in Japan until 2022. Yet a study shows massive potentials for offshore wind energy in Japan. The theoretical capacity potential within the exclusive economic zone (EEZ) is 2720 *GW*, which could easily produce as much energy as to cover the national electricity demand by tenfold (Bardenhagen and Nakata, 2020). There are a few reason, why Europe has so much offshore wind capacity, while Japan has none[24]. In addition to the barriers by the many governmental restrictions and laws as well as the negotiation barriers with the EPCOs, this technology is quite young. It originated in Europe in 1992, where the high population density and good geographic conditions like shallow sea water depth promoted the expansion. The compared high greenhouse gas emission reduction targets in Europe from early stage helped additionally (Bardenhagen and Nakata, 2020). Especially the more determined decarbonization targets has a comparable effect in Japan since the introduction of the "Green Growth Strategy" plan in 2020. Offshore Wind is now supported more adequately by the government (METI, 2021b). As proper research and development was missing in the last decades, results are still pending to the future. Japan has now to face many challenges as the climatic conditions is quite different to that of Europe. First of all, the sea around Japan is

[24]It should be noted that the majority (around 80%) of the offshore wind in Europe is installed by the United Kingdom, Germany and Denmark.

very steep and turbulent. Economically suitable water depth for the traditional fixed-bottom offshore wind power plants is limited to around 50-60 *m*. If the seabed gets deeper, the more expensive it gets and, in this situation, other methods like the new emerging floating offshore wind power plants have to be used. In this case, depth up to 200-300 *m* are considered economical. In short, the geographic situation in Japan makes offshore wind power more expensive, due to the greater potential within the area in deeper sea-bed, where only floating wind turbines are suitable. Additionally, transmission cost will also become an increasing burden, when farms will be built further away from the coast to take advantage of greater windspeeds. However, due to the global falling costs, the interest for offshore wind is growing worldwide. The current global installation trend for offshore tough is still nearly dependend on fixed-bottom plants, as a the newest big-scale project in the United Kingdom "The Dogger Bank Wind Farm" with 3.6 *GW* output shows. It is located between 125-290 *km* off the east coast of Yorkshire, and will be built on Sandbanks with water depth from 18-63 *m* (Hamilton, 2023). Nonetheless, floating offshore wind turbines is projected to increase globally from current 121 *MW* in 2022 to 18.9 *GW* by 2030 and to 264 *GW* by 2050 (Edwards et al., 2023; GWEC, 2022).

Unlike in Europe, Japan has to take other natural conditions into account, such as earthquakes and the following tsunamis, as well as the typhoons. At the moment, offshore wind power is considered underdeveloped in Japan, as existing wind turbines are not suited for the harsh weather conditions of Japan. Especially when typhoons occur, they are not resistant enough to generate efficiently or anything at all, and therefore typhoon proof (T-class) turbines are currently in development (Chen et al., 2023).

Considering the big scale for research investments and the long lead-times, offshore wind energy is further limited to bigger companies. Smaller companies are economically forced to avoid offshore wind energy in favor for other renewable energy resources, like solar energy, which is more accessible and faster to implement.

The situation for offshore wind energy transformed with the changes in law and governmental support by launching tenders for promoting zones. One already commissioned project by a tender is the Akita Noshiro Port wind farm with 140 *MW* in early 2023 (GWEC, 2023), and several bigger projects are now in the development like the Ishikari Bay Offshore by CI Hokkaido GK with 1 *GW* (200 turbines x 5 *MW*) in Hokkaido, which are planned to be completed by 2029 (GlobalData, 2024). The company Mitsubishi won three tenders, granting them a total volume of 1.7 *GW*. The offshore wind farms Yurihonjo with 819 *MW*, the Noshiro-Mitane 479 *MW* both in Akita and the Choshi 391 *MW* in Chiba are expected for commission by 2028 - 2030 (Global Energy Monitor, 2024). All these projects are fixed-bottom projects, and for the

Mitsubishi Projects 134 General Electric turbines with each having a capacity of 12.6 *MW*.

3.5.4 Floating Offshore Wind Turbine Projects in Japan

The era of floating offshore wind energy is still in developing phase, and technological obstacles yet to overcome. Japan's first floating offshore wind farm was commissioned in Fukushima as a pilot and demonstration project as well as a symbol of reconstruction for the region after the nuclear disaster. The wind farm consisted of three turbines and about 60 billion yen was spent. The first turbine Fukushima Mirai 2 *MW* was installed in November 2013, the second turbine Fukushima Shinpu 7 *MW* in September 2015, and the third Fukushima Hamakaze 5 *MW* in July 2016. However, the second and biggest one, was dismantled again after three years in 2018, due to its low capacity-factor of only 2%. While the capacity factor of the 5 *MW* turbine was also relatively low with 12%, the smallest 2 *MW* turbine managed a capacity-factor of 34%. The two remaining turbines were dismantled in April 2021, as they were considered unprofitable and did not reach the intended yields (Edwards et al., 2023; Radtke, 2018; Kinoshita, Hiratsuka, and Isogai, 2021). Nevertheless, the gained experience from this project will now be used by Tokyo Gas and Shinobuyama Fukushima Power in a new project with two 15 *MW* turbines on a near site. The environmental impact assessment process for this project started in February 2023 (Snieckus, 2023). Fukushima is not the only site, where floating wind turbines were built. In Goto, Nagasaki a small 100 *kW* test turbine had a test run between 2012-2016[25] and went into full operation after the test phase (Toda Corp, 2024). In 2021, the company decided to build a little farm of 8 turbines with 2.1 *MW* (Yap, 2022), which were supposed to go in operation in January 2024, but due to structural defects the project is postponed by two years (Durakovic, 2022). Another project is a two bladed 3 *MW* wind turbine in Kitakyushu, which began the test operation in 2019 (Durakovic, 2019).

Compared to the new fixed bottom wind farm projects, the floating ones are very small scaled. It shows that the technology is not fully developed yet. In addition, the current state of knowledge is limited by insufficient data and numerous unresolved questions, which is why larger investments are associated with very high risk, despite the higher potential.

[25] In 2013, it was replaced with a 2 *MW* turbine (Toda Corp, 2024)

3.5.5 Social Acceptance toward Wind Energy

At the beginning, wind power was perceived as an environmentally friendly energy resource. However, after developers and stakeholders would neglect the important issues of noise pollution or landscape disfigurement, the social acceptance decreased over time. Constructions in national parks or conversation areas was not welcomed by local communities and opposition against onshore wind energy gradually increased. This led ultimately to the mandatory[26] EIA Act in 2012 (Mizuno, 2014). Considering the enthusiastic plans by the government, the social acceptance will be another enormous barrier for the development of wind energy. But there could be measurements to improve the social acceptance. A recent study in Norway has found that the social acceptance for onshore wind power was decreasing the more wind farms were installed. In the last decade between 2012 and 2021 the installed capacity grew from 1 GW to 5 GW. Surveys showed that in 2012 about 76% had a positive opinion, while only 17% were negative and 10% neutral. In 2021 positive opinion declined to 43%, while negative responses increased to 43% and neutral to 13% (Jikiun, Tatham, and Oltedal, 2023). Offshore Wind energy remained popular, maybe because most of the installed capacity is built onshore. As of 2022, the installed capacity for onshore and offshore wind energy in Norway was 5068 MW and 66 MW, respectively (IRENA, 2024b). The study in Norway further shows, that it is possible to still increase the social acceptance. The key issue might be to raise the benefits for the concerning community. Rural communities complain that they have to carry all the weight for climate change. While the whole nation and urban people benefit from a cleaner energy, they alone have to endure the disadvantages of landscape disfigurement, noise pollution, loss of property value or interference with nature. Global benefits against local demerits misfit rural citizens. Future production of green hydrogen alone through wind power seems to be insufficient. However, if this hydrogen is used locally, like making the transport and industry green, then the benefits increase, and social acceptance is raised significantly particularly among younger and more educated inhabitants. Financial benefits also increase the support. With such measurements the conflict of interest and the resulting separation between rural and urban citizen disappear (Jikiun, Tatham, and Oltedal, 2023). In Japan this might have a great impact likewise. By increasing the benefits for locals, wind power as well as other renewable energy resources will have a positive impact and help further to increase the diffusion of space taking renewable technologies. Hence, it is even more necessary to raise public awareness of the possibilities by the hydrogen technology (Gordon, Balta-Ozkan, and Nabavi, 2022). The acceptance of hydrogen itself have to be considered as well. According to a study, hydrogen becomes more popular when a local area benefits from economic growth. This was achieved with a fueling stations for hydrogen, which not only increases energy security but also

[26]The EIA process was from 2003-2012 voluntary and became mandatory in 2012.

creates jobs (Irie and Kawahara, 2019).

3.5.6 Potentials of Wind Energy in Japan

3.5.6.1 Offshore Wind Energy Potential in Japan

Among the renewable energy technologies, wind energy has the greatest potential. Especially in the offshore area. Bardenhagen and Nakata state a theoretical offshore potential of 2720 GW. In their study no restrictions other that the consideration of the exclusive economic zone (EEZ) of Japan were made. Under the assumption of a 1 km distance between turbines, the numbers would result in 256,619 turbines nationwide. The minority of 64,198 turbines lies in shallow water (<50 m, suitable for fixed-bottom) and the majority of 192,421 turbines is in deep water (50 - 200 m, floating turbines) (see Figure 3.9). If a 10.6 MW turbine is installed on each node, the theoretical potential would be 680 GW and 2040 GW, respectively. Even if restrictions due to various reasons have to be considered, wind power alone has a great potential to meet the national electricity demand with a fair share. According to Bardenhagen and Nakata 26,210 turbines would have to be installed to meet the electricity net-balance between supply and demand (Bardenhagen and Nakata, 2020). However, at the present the current promotion zones are limited to territorial waters, and there are still no laws for the utilization of the exclusive economic zone (EEZ) in Japan yet (JWPA and GWEC, 2022).

Figure 3.9: Offshore wind energy potential around Japan by zones of water depth: <= 50 m in light blue; 50 - 200 m in sky blue (Source: Bardenhagen and Nakata, 2020)

3.5.6.2 Onshore Wind Energy Potential in Japan

The wind energy potential on land stays in direct competition to other resources or other land-use purposes. Thus, the wide interests by different parties stay in conflict to each other, and several restrictions are imposed to renewable energy resources. Especially the space-taking technologies, like solar, wind and bioenergy, are the most affected by these wide-ranging restrictions. For instance, the preservation of untouched nature and national parks or the noise-pollution by wind turbines limit the suitable area for renewable energies. Then the question arises as to which technology should be used. If solar and wind technology is compared only by energy density, then solar energy should be used, as the density is higher. However, there are many other factors that have to be considered as well, like land textures or the average wind speeds. A study finds that if land-use restrictions are included the suitable area for onshore wind and solar energy is reduced to a small portion of 0.9% or 3428 km^2 of all contiguous land, while further limitations like economic restrictions or grid access were still not even considered yet. The suitable area could still be used for other purposes as well. In 28% of this area wind speed is too low ($< 5\ m/s$) and therefore only suitable for solar energy. In the rest both technologies are possible. On the contrary, land textures like slope of the land limit the safe use of solar panels, due to risk of landslides in Japan. Only the minority of the competing area is flat, and wind energy could be the better option for non-flat areas. If nonetheless, only solar energy would be installed in all suitable areas instead of wind energy, which would maximize the capacity and 230 GW could be achieved. This could generate 250 TWh per year, worth of 28% of the total national electricity demand in 2018. The area only suitable for solar energy makes 64 GW, while the land suitable for both technologies has either the potential for 166 GW solar energy or 25 GW for onshore wind energy. The huge gap is due to the different installation density for mentioned resources. This study assumed 67 MW/km^2 for solar energy and 10 MW/km^2 for wind energy. If the land was opted for wind energy, the electricity output would decrease to 130 TWh[27] per year or to 15% of the total national electricity demand in 2018 (Obane, Nagai, and Asano, 2020). However, there are still other factors that have to be considered as well.

The diversification of energy sources and resources for a greater energy resilience could be one of those aspects (ANRE, 2021c). The onshore wind potential is neglectable compared to the offshore wind potential. It might be a robust solution to maximize the land-use with solar energy while using wind as a pure offshore energy resource. On the contrary, the greater potential of offshore lies within in the deeper ocean, where the new floating wind technology has to be used, which is still not a commercially available technology. Onshore wind energy could therefore be the transitional technology

[27] This leads to a capacity factor of 27.6%. It marks the upper limit for onshore wind, and will be used in the potential Table 3.5 at the end of the chapter.

until the floating technology is ready for the market. Certainly, there are currently big-scale fixed-bottom offshore wind farms in pre-construction phase but are few in numbers. According to the Ministry of Environment (MOE), Japan has also great onshore wind potentials, if areas from private and national forests are included. The potential would in this case correspond to 286 *GW* (Obane, Nagai, and Asano, 2020). Onshore wind could therefore be supportive in a faster dissemination of wind energy due to its long lead times. The Japanese Wind Power Association (JWPA) predicts an installed wind power capacity of 140 - 170 *GW* (consisting of 40 *GW* for onshore, 40 *GW* for fixed bottom and 60-90 *GW* in floating offshore, until 2050 and thus solidifies greater onshore potential (JWPA, 2023).

Another aspect is the spatial distribution of the wind potential. The greatest portions of Japan's wind potential are located in the north of the country in Hokkaido, followed by the southwest in Kyushu, and on third in the northern part of Tohoku. However, especially in the northern regions the population density and thus the demand of energy in these parts is relatively low. In order to harness the full potential of wind energy it is necessary to transport the energy to areas with higher demands. The transmission grid would have to be greatly enforced to eliminate bottlenecks (Bardenhagen and Nakata, 2020), which would also stabilize the whole electricity system as the uncertain energy production from volatile renewable sources like wind and solar can be mitigated (Delage, Matsuoka, and Nakata, 2021).

Another study shows that Tohoku is one of the best regions to develop offshore wind, because it is closer to the demand centers than Hokkaido or Kyushu. It is next to the Kanto region that includes Tokyo. The simulation of the study shows that 91 *GW* offshore wind energy could be integrated effectively, with focus of the distribution directly into the demand regions. The advantage would be a higher integration of wind generation in the energy mix, without the need for reinforcement of the existing onshore transmission grid. However, the current policy of the government envisages to use the wind potential for hydrogen production by water electrolysis. For this purpose, the best deployment area are Hokkaido and Kyushu. The production of hydrogen directly on site allows to use the full potential of the wind in a most efficient way, while simultaneously mitigating the need for reinforcing the transmission grid (Chen et al., 2023; (Obane, Nagai, and Asano, 2020).

3.5.7 Conclusion on Wind Energy in Japan

Japan's substantial wind energy potential has been neglected until the decarbonization targets were expanded in 2020. The government prioritized solar energy, while several factors hindered the development of wind energy. These included technological challenges, such as the fact that the greatest potential is found in offshore locations, particularly within the still-emerging floating offshore sector, and the vulnerability of turbines to typhoons. Additional obstacles include the limited public acceptance and that the highest onshore wind potential is concentrated in rural areas with relatively low electricity demand. Moreover, grid interconnections to major demand centers remain highly constrained.

The impact of the government's increased efforts to expand wind energy will only become evident in the future. While initial progress has been made through the allocation of offshore wind farm permits, the completion of these projects, their start of operations, and their contribution to electricity supply are still pending.

At the end of this chapter, an estimate of wind energy potential is provided in Table 3.5. Between 2010 and 2021, capacity factors for onshore and offshore wind energy in Japan ranged from 20% to 25.3% and 17.6% to 23.1%, respectively (IRENA, 2024b). The estimated electricity generation for onshore wind is between 3.5 and 691.5 TWh, while the theoretical electricity generation potential for offshore wind could reach 4.1–5.5 PWh.

	pot. range	theo. pot.	c-factor	est. e-gen. pot.
Onshore wind	2 - 40 GW	286 GW	20.0 - 27.6%	3.5 - 691.5 TWh
Offshore wind	-	2720 GW	17.6 - 23.1%	4.2 - 5.5 PWh (theo.)

Table 3.5: Wind energy potential in Japan

3.6 Hydrogen

When Japan introduced their Intended National Determined Contribution (INDC) in 2015 for the Paris agreement, and further their short and long-term energy strategy plan for 2030 and 2050, respectively, they did not include hydrogen as option for decarbonization (UNFCCC, 2015). Japan first mentioned hydrogen in the end of 2017, which was then included in the updated strategy plan in 2018 of Japan (METI, 2017; METI, 2018). Their actual goals were still vaguely defined as "becoming a hydrogen society".They only described in general terms how they intended to achieve this, such as by building infrastructure, etc. The only actual data they stated was to procure about 300,000 tons of hydrogen annually and to reduce the power generation cost for hydrogen to 17 yen/kWh (or 30 yen/Nm^3) around 2030 (METI, 2018). The government stated that the initial phase of hydrogen production will be through inexpensive imported hydrogen produced from fossil fuels. From this point, to build gradually and consistently a cleaner infrastructure and production chain. Since building up a comprehensive hydrogen infrastructure is time-intensive, Japan additionally wants to promote other technologies for decarbonization. Technologies that can use the existing infrastructure and therefore be effective in the immediate future. For instance like using ammonia directly as fuel or methanation of hydrogen with carbon dioxide (METI, 2018). Both options are evidently CO2 emission neutral, because ammonia (NH_3) does not contain carbon, and therefore no carbon would be emitted. In case of methane (CH_4), only the previously bounded CO2 during the methanation process would be released again, which makes it in sum a carbon-neutral technology. It could be inferred that ammonia represents a more viable solution compared to hydrogen. However, ammonia is toxic and produces also significant levels of toxic pollutants (NO_x and NH_3 residuals) when combusted. Those pollutants produce ozone and acid rain (Herbinet, Bartocci, and Grinberg Dana, 2022; Rasmussen, 2021; Sharma and Kumar, 2019). Hence, this can not be a long-term solution for the climate-change. It would merely replace the CO2 emissions with non-CO2 greenhouse gas emissions, where the extend of the environmental - but also anthropogenic - impact could be more problematic. Despite that, ammonia can be useful as an energy carrier for hydrogen. The storage of hydrogen in the form of ammonia can take advantage of the previously mentioned use of existing infrastructures. Additionally ammonia can be stored and transported more easily, while also having a higher energy density than hydrogen (Herbinet, Bartocci, and Grinberg Dana, 2022; Cesaro, Nayak-Luke, and Bãnares-Alcántara, 2021; Augsten, 2022). The energy density for ammonia and hydrogen in the liquefied conditions are 11.38 GJ/m^3 and 8.52 GJ/m^3, respectively (Augsten, 2022; Barelli, Bidini, and Cinti, 2020).

3.6.1 Frontrunner Projects to stimulate Trend

Although initially articulated in broad terms in 2017, Japan was among the first countries to implement a national hydrogen strategy, and therefore setting a clear direction for its energy future. Japan intends to introduce 800,000 fuel cell vehicles (FCVs) by 2030 along with 900 filling stations. 2019 and 2020 there were 3,600 and 3,800 registered FCVs in Japan, respectively, which makes the determined goal of 800,000 FCVs in the transport sector until 2030 appear highly infeasible (Kang, 2020; AHK Japan, 2021). The country used the Olympic games in 2021 to introduce and enforce public awareness for hydrogen as energy source through its "hydrogen society" project. This is to accelerate the growth of its strategic aims for hydrogen (IOC, 2021).

With setting the direction from the government, the private sector also began to increase its efforts toward a hydrogen society. Toyota together with Honda and 86 other companies founded the initiative Japan Hydrogen Association (JH2A) in December of 2020 and as of June in 2024 its members grew to 451 companies/organizations (Japan Hydrogen Association, 2024). Together with the government they started four pilot projects to enforce the growth of the sector, increasing the long-term benefits for all. One of those projects is the already mentioned „hydrogen society" at the Olympic games in 2021 in Tokyo, where the whole Olympic village of 4000 accommodations for the athletes was powered on hydrogen. Additionally, the transportation within the village and to the venues was mainly (90%) carried out by electrical vehicles like FCVs and battery electric vehicles (BEVs) (AHK Japan, 2021; IOC, 2021). A similar futuristically and visionary project, the "Woven City" is a small city for 2000 people, where like the Olympic village, generated energy will be supported by fuel cells. The other remaining two projects are more practical. One is a hydroelectric power plant in Shiranuka Town in Hokkaido with 200 kW, constructed by the Toshiba company. This power plant is used to produce 35 Nm^3 of hydrogen per hour by electrolysis and is locally used through fuel cells in public buildings, farms and FCVs. In Cooperation with Iwatani company, who manages the transportation, they wanted to show that a complete hydrogen supply chain is possible. They chose the Hokkaido region, because it is rich in renewable resources and therefore suitable for a fast implementation of a carbon-free energy chain (AHK Japan, 2021; Toshiba, 2018). The fourth project is the "Fukushima Hydrogen Energy Research Field" (FH2R), where a big solar energy park with 20 MW was installed in 2020 to produce hydrogen. This pilot project is conducted to gain experience for future plants, which will be implemented abroad, where hydrogen could be produced more economically. All these projects have the purpose of increasing the development and introduction of hydrogen into society and marks the initial phase of the hydrogen society (AHK Japan, 2021).

3.6.2 Intensified Strategic Aims for Hydrogen toward 2050

After Japan's prime minister Suga officially declared carbon-neutrality by 2050 in October 2020 (METI, 2021b), a new strategy plan was released in 2021, and the goals for hydrogen were defined more precisely (ANRE, 2021c). Hydrogen as a new resource - along with ammonia - is now included in the power generation mix and it should contribute 1% by fiscal year 2030 (see Figure 3.10). With an anticipated total electricity generation of around 934 TWh this equals to 9.34 TWh (ANRE, 2023a). Their former goal of annually supplying 300,000 tons of hydrogen until 2030, has already surpassed to the current level of approximately two million tons/year, but significantly higher targets to three million tons/year and 20 million tons/year by 2030 and 2050, respectively has been decided (Obayashi, Uranaka, and Takemoto, 2023; METI, 2021a). As for the cost reduction, Japan is with 100 yen/Nm^3 still far from the 30 yen/Nm^3 goal until 2030, but by setting standards and through international expansion, Japan is confident in its ability to achieve this target. Not only in the power sector but also in the transport, industry and building sector goals are set, like the expansion from 167 in 2023 to 900 H2-stations for FCVs or stationary fuel cells "ENE-Farms" in private homes (Japan H2 Mobility, 2023; AHK Japan, 2021).

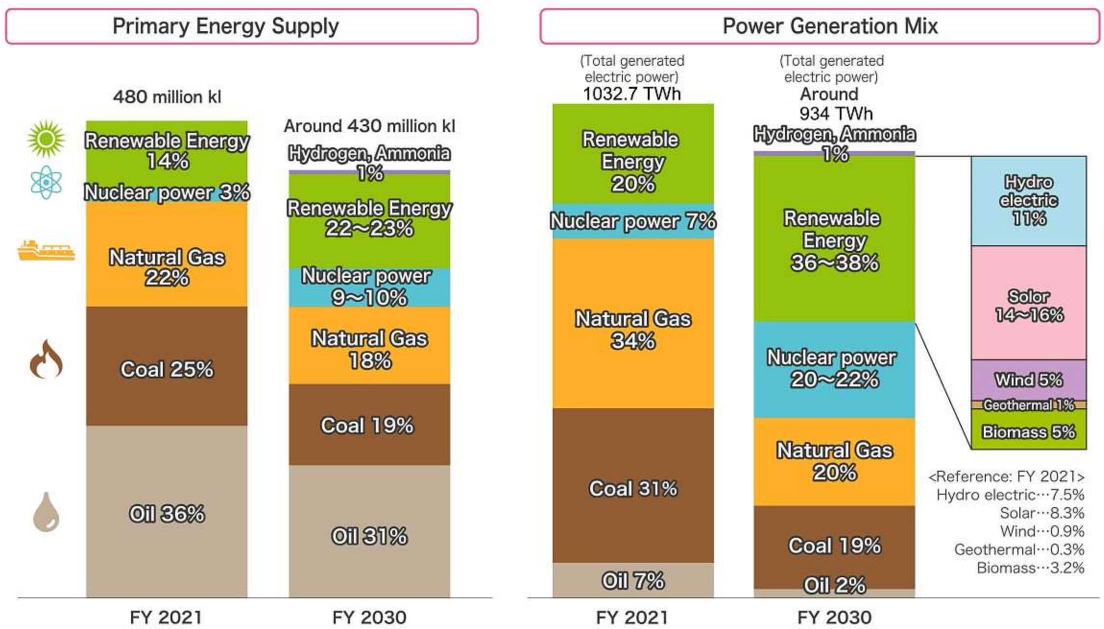

Figure 3.10: Power generation mix of fiscal year 2021 and targets for fiscal year 2030 (Source: ANRE, 2023a)

3.6.2.1 Residential Fuel Cells "ENE-Farms"

The target is the installation of such home fuel cells (see Figure 3.11) in 2.5 to 5.3 million of the 53 million households until 2030. Less than 450,000 units until 2022 were installed yet (ANRE, 2023a). These units can supply 0.3 to 1 kW of electricity, include a 200 liter hot water tank at 65°C, and are supposed to meet 60% of the residential electricity demand (ANRE, 2021c; AHK Japan, 2021; JAPAN LP Gas Association, 2024). Those full cells will be powered by liquefied petroleum gas (LP gas), which is in the end not a carbon neutral solution. However, the main idea of these units is not the total energy self-sufficiency by a clean carbon-neutral resource, but mainly to reduce the heat losses and therefore increasing the total efficiency (see Figure 3.12). This system cuts the residential carbon-footprint in half and if solar panels are added the savings are nearly at 60% (Williams, 2017). These "farms" include an automated learning system, where hot water is supplied, when needed, while electricity is merely a byproduct (ITOCHU ENEX Co.LTD., 2024). If in the long-term the energy resource from LP gas is replaced by green hydrogen, and/or the unit sizes is increased, the carbon footprint of households could be tremendously decreased or even eliminated entirely, which is together with office buildings responsible for 10% of the national CO2 emissions (METI, 2021b). In essence, it is a decentralized co-generation system, which also has the benefits of blackout resistance due to natural catastrophes like earthquake or taifuns. However, considering the costs associated with these systems, which are not subsidized by the government, renders them economically unviable. Compared to an older version, Tokyo Gas and Panasonic Corporation introduced a newer system in 2013, which would be 27% less expensive, but is with 2 million yen[28], still quite expensive (Panasonic Group, 2013). The costs for such ENE-Farm products did not fall at all, but even increased in 2023. The sale price from Toho Gas is nearly unchanged at 2 million yen[29], except that the power output range decreased to 0.2 - 0.7 kW with an smaller 100 liter tank. To make this solution more inviting, it is now possible to rent this co-generation system for 2,860 yen (∼20 EUR) per month and 116.51 yen/m^3 (Toho Gas, 2024).

3.6.2.2 International Supply Chains for Hydrogen

At the present, there are two major hydrogen supply streams from foreign countries. The Hydrogen Energy Supply Chain (HESC)[30] imports hydrogen from Australia and the Advanced Hydrogen Energy Chain Association for Technological Development (AHEAD) from Brunei. In both supply chains hydrogen is not produced by renewable

[28] ∼ 17,000 EUR, 1 EUR = 115-120 yen, change rate of 01.2013 (boerse.de, 2024)
[29] ∼ 12,700 EUR, 1 EUR = 156-160 yen, change rate of 10.2023 (boerse.de, 2024)
[30] consisting of the two parts "HySTRA" and "HEA"

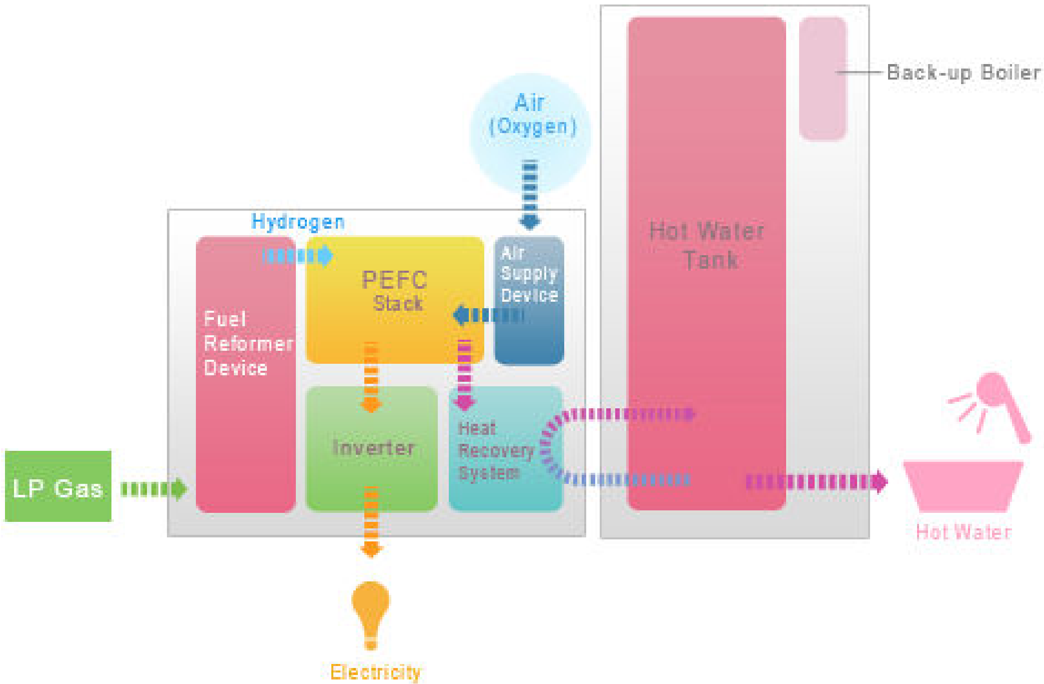

Figure 3.11: The structure of the "ENE-Farm" home fuel cell (Source: JAPAN LP Gas Association, 2024)

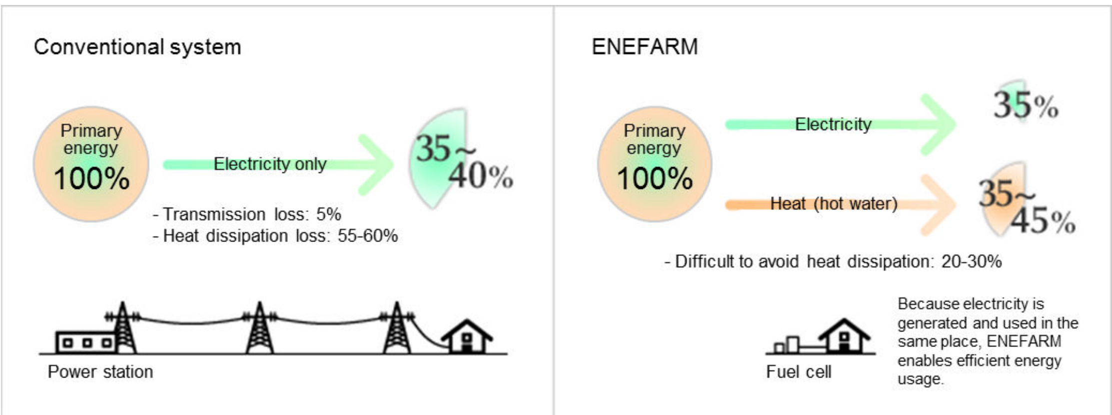

Figure 3.12: Concept of the "ENE-Farm" home fuel cell: Enhancing total energy efficiency by eliminating heat losses (Source: ITOCHU ENEX Co.LTD., 2024)

energy but from fossil fuels. Despite that, there are many lessons that are learned from these streams. Both use different technologies.

In case of HESC, brown coal is converted into hydrogen by gasification in Australia. The resource in the Latrobe Valley near Melbourne for this stable line is worth of 240 years of the total power generation in Japan. The main technological issues for this supply line are achieved by the Kawasaki Corporation. In the first stage about five tons of hydrogen is liquefied daily by cooling down the medium to -253°C to increase the energy density by a factor of 800 and to make the transportation more efficiently. However, safe storage is the key issue. Kawasaki has experience since the 1980s with liquefied natural gas, where the cooled medium (-162°C), is carried with their tankers to Japan. For the safe storage and transportation of liquefied hydrogen, Kawasaki developed the world's first liquefied hydrogen carrier "SUISO FRONTIER" with a capacity of 75 tons (Kawasaki, 2024). It started its operation on January 21 in 2022. With this supply chain Japan aims to import 225,000 tons of hydrogen annually until 2030. At the current initial state, carbon capture measurements when producing the hydrogen in Australia, are not deployed yet, but are aimed until 2030. The Australian government approved further financial resources for this purpose and is determined to become a key exporter for hydrogen (Wirtschaffswoche, 2022; CSIRO, 2022).

In the second supply chain, hydrogen is imported from Brunei. AHEAD uses a much easier technology and already began with the supply in April 2020. This was in fact the world's first international hydrogen transport. In this process, hydrogen is produced from natural gas via steam reforming and subsequently combined with toluene through hydrogenation to form liquid methylcyclohexane (MCH). This compound, marketed under the trade name SPERA Hydrogen (derived from the Latin word "spera," meaning hope), offers improved manageability. The advantage lies in the safe and cost-effective storage and transportation of the substance. Compared to normal hydrogen the density is 500 times higher. Transportation can easily be executed in commercial freight container. After transportation hydrogen is again separated from toluene, which will be reused for the next freight, resulting in a cycled process (Chiyoda Corp., 2024). This technology could be particularly valuable in critical situations or for short-distance applications, such as domestic transportation in densely populated areas, where the development of larger infrastructure, such as pipelines, is either economically unviable or technically infeasible.

3.6.3 Gradual Transition into a Carbon Neutral Hydrogen Technology

Japan aims with such projects and supply chains to achieve the carbon-neutrality in 2050. In the official strategy plan of Japan by the government did not state further long-term targets for hydrogen until 2050. However, there is an additional strategy plan released by the Ministry of Economy, Trade, and Industry (METI) on 25th of

December 2020, which is in conformity with the existing plan. This industrial policy plan is called the "Green Growth Strategy 2050" and states the targets more precisely. The cornerstones include the complete decarbonization of the electricity sector, the expansion of electrification across all sectors, and the maximization of renewable energy dissemination to the greatest extent achievable within realistic constraints. The electricity demand is expected to increase by 30 - 50% to ∼1300 - 1500 TWh. The government presumes that around 50 - 60% of the electricity demand can be covered by renewable energy. 30 - 40% of the electricity generation will still be realized through thermal generation with carbon capture & storage and nuclear power. The remaining 10% is planned to be generated by hydrogen and ammonia. Where electrification is unattainable, hydrogen should be used (METI, 2021b). This also applies to the thermal generation, where new technologies allow hydrogen but also ammonia to be used as fuel. The Kawasaki Company for instance has already developed such a gas turbine in a demonstration project in 2018 in Port Island in Kobe, where any kind of mix between hydrogen and natural gas can be used. This project is a co-generation system with one MW, subsidized and conducted by New Energy and Industrial Technology Development Organization (NEDO). The flexibility of the fuel mix enables a gradual transition to zero-carbon and cost optimization (Kawasaki, 2024; Chiyoda Corp., 2024).

3.7 Summary of the Potentials of Renewable Resources in Japan

Historically, the utilization of renewable energy for electricity generation focused mainly on hydropower from the beginning of the electricity era in the late 19th century. The usage of hydropower incrementally progressed over the decades, and now the sites with output approximately greater than 30 MW are all considered developed. Therefore, additional potential for hydropower in Japan is the most limited among the renewable energy technologies, and the country needs to focus more on the other technologies. After the oil crisis in the 1970s, solar technology received the highest interest and recently in 2021 it emerged as the technology - among the renewable technologies - with the highest electricity generation, which was until then hydropower (IRENA, 2024b).

3.7.1 Full Load Hours and Capacity Factor

At the end of this chapter, one of the most prominent factors of a power plant, the full load hours, will be explained. The full load hours describe for how long an electric generator runs throughout one year, and therefore how much electricity the generator produces. By dividing the full load hours by the hours of a full year of 8760 hours, it becomes a dimensionless factor and is called the capacity factor. This allows to compare the actual produced electricity to the maximum it could produce, if the power plant would be continuously at full operation. For instance, 100% means, that a power plant operated at maximum capacity in every single hour of the year. If a power plant is shut down due to maintenance or other reasons and is operated only 5000 hours at maximum capacity in a year, then the capacity factor of that power plant drops to 57% ($5000\ hours/\ 8760\ hours = 0.57$). Depending on the technology and development of a technology this factor can range from around 10% to almost 100%. For instance, solar power plants have one of the smallest capacity factors. In 2010, the global average weighted capacity factor for solar power plants was 13.8% (IRENA, 2023b). Since solar power plants depend on the light of the sun, they can only produce energy during daytime, which alone limits the capacity factor to an approximate maximum of 50%. The second limitation is the solar irradiance, that is affected by latitude and climate. The higher the sun is above the horizon in the sky, the more solar radiation is available. This automatically results in a typical daily performance curve, with the maximum being reached in the middle of the day. On the contrary, nuclear power could theoretically reach a capacity factor of almost 100%. Nuclear power plants are operated throughout the entire year and are commonly only shut down for maintenance reasons. In 2021, the global average capacity factor for nuclear power was 82.3% (World Nuclear Association, 2024a).

Generally, the capacity factor can be actively influenced by simply increasing or reducing the output within the operation range of the power plant. This manipulation allows to adjust supply accordingly to the desired energy demand. Although from the economic point of view, high capacity factors are targeted, the priority lies in balancing the supply consistently to the demand. Capacity factors less than the theoretical maximum achievable are the result. These values are also the typical values found in literature. However, there are technologies, where energy production cannot be controlled freely, except for lowering the output by cutting off excessive energy. Production is highly dependent on natural factors and is hence unpredictable, or "volatile". These technologies are solar and wind power. Subsequently there is no distinction between the real-life and the theoretical possible capacity factor in literature. Values for the capacity factors for these technologies found in the literature show the technological limits and are also subject to technological development. For instance, while the global average capacity factor for onshore wind power in 2022 was around 37%, the same factor was in Japan only around 25% (IRENA, 2023b). This is due to the fact that the size of wind turbines in Japan is still significantly smaller than the global average and subsequently the wind yield is also lower. An improvement in the capacity factor is thus linked to technological progress. Overall, this results in country-specific factors that are affected by the respective state of development of the technologies in each country.

In summary, the capacity factor is a measurement of the quality of a technology and the individual values for each technology have an great impact on the needed capacity, that has to be installed to produce the same amount of energy. Based on the previous references, and assuming all other factors are disregarded, the required capacity for solar energy could be approximately six times greater than that of nuclear energy (82.3% / 13.8% = 5.96).

3.7.2 Conclusion on Japan's Renewable Energy Potential

From the current perspective, Japan possesses abundant renewable energy resources to achieve the decarbonization of its electricity system. Looking beyond 2050, it may become feasible to fully decarbonize the nation's energy consumption, as renewable energy sources theoretically offer sufficient potential. The theoretical[31] and realistically achievable potentials for Japan's renewable energy are summarized in Table 3.6.

[31] Theoretical potential refers to the capacity calculated without considering anthropogenic factors such as social acceptance, regulatory constraints, and legal restrictions, and is limited only by topographical and current technological capabilities.

Among these, offshore wind energy emerges as the most promising technology, while geothermal energy also presents significant potential — an uncommon trait from a global perspective. Bioenergy, which has thus far played a minor role in electricity generation and has been primarily used for heat production, may gain greater importance in the future. Conversely, solar energy could face increasing challenges moving forward.

	pot. range	theo. pot.	cap. factor	est. e-gen. pot.
Solar (buildings)	292 GW	292 GW	10.8-13.8%	276-334 TWh
Solar (land)	64-230 GW	230 GW	10.8-13.8%	61-278 TWh
Onshore wind	2-40 GW	286 GW	20.0-27.6%	4-692 TWh
Offshore wind		2720 GW	17.6-23.1%	4.2-5.5 PWh
Hydropower	6.7-12 GW	136 TWh	46.4-61.0%	27-64 TWh
Bioenergy	2.836 EJ			197 TWh
Geothermal	23.47-50 GW	50 GW	54.3-74.3%	112-325 TWh

Table 3.6: Theoretical & realistic potential range of renewable energy in Japan by technology

4 Electricity Costs in 2050

In the last decade renewable energy costs for certain technologies decreased tremendously on a global average basis to a point where these technologies have become competitive to non-renewable technologies. However, the comparison by solely the investment costs for the different technologies is not sufficient as the individual characteristics of them have to be considered as well. The comparison is achieved by relating all costs incurred over the lifetime of a power plant to the produced energy in kWh. These costs are called the levelized costs of electricity (LCOE) and are measured in USD/kWh. Recent data show, that the global weighted-average LCOE for solar photovoltaic and onshore wind energy have become even less expensive than the cheapest fossil fuel-fired option by 29% and 51%, respectively. Major reasons for this development are technological improvements and economics of scale. On the contrary, other renewable energy technologies are still more expensive and future cost development is uncertain as it depends on a large number of factors. The calculations in this chapter are mainly based on the data by IRENA and the IEA (IRENA, 2023b; IEA, 2023b).

4.1 General Terms for determining Electricity Costs

In this section, the various terms used to determine the electricity costs are explained in more detail. The general solution method is also presented.

4.1.1 Investment Costs

Investment costs play a major role for investors. Some technologies are significantly more expensive than others, however it does not automatically guarantee higher revenues. There are many other factors that have to be considered as well. Technologies with high investment costs can lead to avoidance in favor to other less expensive technologies. An important factor for an investment is the timing. Newer technologies have significantly higher investment costs. These costs decreases over time and due to development. The technological learning rate LR is in that regard an excellent indicator and shows how fast the costs of a technology decreases, when the installed capacity is doubled. The investment costs can be calculated by Equation 4.1, where the the learning rate is indirectly included into the equation by the dimensionless parameter b. The learning rate can then be calculated by the simple Equation 4.2 and is given in percent.

$$C(t) = C(0)Y(t)^{-b} \tag{4.1}$$

$$LR = 1 - 2^{-b} \tag{4.2}$$

where:

$C(t)$ = Investment costs for a unit at time t,
$C(0)$ = Investment costs for the first unit,
$Y(t)$ = Cumulative installed capacity,
b = Parameter to measure the learning rate,
LR = Learning rate

Future predictions should be treated with caution. Nevertheless, long-term statements would not be possible without taking future cost reductions and efficiency improvements into account in the calculations. Cost reductions become smaller with time as the doubling of the cumulative output requires larger production volumes. When new technologies emerge, investment costs are very high, but revenue low. For investors it is necessary to be aware of the exact investment costs at any given time to maximize their profits by investing at the right time. With a given learning rate and a given cumulative installed capacity at time T, the investment costs at time T can be calculated by Equation 4.3.

$$C(t) = C(T)\left(\frac{Y(t)}{Y(T)}\right)^{-b} \tag{4.3}$$

where:

$C(T)$ = Investment costs for a unit at time T,
$Y(T)$ = cumulative installed capacity at time T

4.1.2 Levelized Costs of Electricity

The levelized cost of electricity (LCOE) in USD/kWh is a function of various parameter and can be calculated by Equation 4.4 in general, where C_C represents the annual capital costs, C_{OF} the annual operational fixed costs and C_{misc} other performance-dependent costs, in the unit USD/kW. These costs are fixed costs that arise in any case, whether the power plant is shut down or not. By dividing these costs by the annual full load hours FLH, the fixed costs are distributed over the annual term. The fuel costs c_{fuel}, the labor-dependent operating costs c_{OC} and the CO2-dependent costs c_{CO_2} are costs in USD/kWh, and only arise upon operation of the power plant.

$$LCOE = \frac{C_C + C_{OF} + C_{misc}}{FLH} + c_{fuel} + c_{OC} + c_{CO_2} \tag{4.4}$$

The annual capital costs C_C in USD are the total investment costs I_0 in USD spread into annual costs (see Equation 4.5) by the capital recovery factor (CRF), which considers the lifetime n of a power plant as well as the interest rate r (see Equation 4.6).

$$C_C = CRF \cdot I_0 \tag{4.5}$$

$$CRF = \frac{(1+r)^n r}{(1+r)^n - 1} \tag{4.6}$$

In case of renewable energy, CO2 costs are non-existent[1] and further more fuel costs are non-existent for solar, wind, geothermal and hydropower. Fuel costs have to be considered only for biomass, hydrogen and nuclear. In literature operational cost C_{OF} and miscellaneous costs C_{misc} are sometimes merged and referred to as operational and maintenance (O&M) costs $c_{O\&M_{fix}}$. Sometimes O&M costs are related to kWh as $c_{O\&M_{var}}$ and include in that case the labor-dependent operating costs c_{OC}. Equation 4.4 for the levelized costs of electricity can then be simplified to Equation 4.7.

$$LCOE = \frac{I_0 \cdot CRF + C_{O\&M_{fix}}}{FLH} + c_{O\&M_{var}} + c_{fuel} \tag{4.7}$$

It should be clear that the LCOE is highly dependent on a large number of assumptions made in the calculation, and therefore should only be seen as an economic indicator. A perspective of the LCOE into the far future is even more difficult. However, the importance of decarbonization makes it inevitable to estimate future costs. Therefore, with consideration of the governmental decarbonization target by 2050 in Japan, the LCOE will be calculated in 2050.

[1]exception is bioenergy, however it its considered as net zero emission technology

4.2 Global Investment Costs for Renewable Energy in 2050

In order to assess the total electricity costs in Japan 2050 it is necessary to calculate the investment costs with Equation 4.3 first. The needed data for the renewable energy is delivered by IRENA (IRENA, 2023b). Due to the Japan specific missing data an indirect route will be made by assessing the situation on a global scale. The available data reaches back to 1984, however only for onshore wind energy. A total set of data for all technologies are available between 2010-2022. The given global weighted average total installed costs are shown in Appendix Table A2. The data for the global installed renewable electricity capacity are taken from the IRENA Online Database shown in Appendix Table A3 (IRENA, 2024b). The parameter b and subsequently the learning rate LR could be calculated by the Equations 4.3 and 4.2 and are shown in Table 4.1. The time-frame for the calculation is quite short and should be therefore considered with caution. To mitigate the influence of statistical outliers when calculating the learning rate according to Equation 4.3, the costs for the chosen base year 2012 were created by averaging the years 2010-2014. The resulting learning rates are higher than in other literature (IEA, 2023b). While the higher LR for solar and wind energy can be justified by the increased efforts and faster technological advances globally, the LR for the last three technologies (hydropower, geothermal and bioenergy) have to be adjusted. In terms of hydropower, the learning rate is set to zero, as this technology is one of the oldest and improvements nearly non-existent. Fluctuations in total installed costs and subsequently the calculated learning rate derive merely due to fluctuation in the economy. The learning rates for geothermal and bioenergy seems with 35% and 26%, respectively, quite high. For this reason, a more conservative approach was taken by halving the learning rates to 17.4% and 13%.

	calculated values		adjusted values	
	-b	LR	new -b	new LR
Solar photo.	-0.61	34.68%	-0.61	34.68%
Offshore wind	-0.19	12.62%	-0.19	12.62%
Onshore wind	-0.44	26.19%	-0.44	26.19%
CSP	-0.78	41.64%	-0.78	41.64%
Hydropower	2.67	-535.58%	0.00	0.00%
Geothermal	-0.62	34.80%	-0.28	17.40%
Bioenergy	-0.43	25.93%	-0.20	13.00%

Table 4.1: Calculated global learning rates and parameter b for renewable energies

In order to calculate the installed costs for 2050 using Equation 4.3, further data on installed capacity in 2050 are needed. The IEA has published data on this in the World Energy Outlook (WEO) (IEA, 2023b). The outlook states the global installed capacities by technology in the years 2030, 2035, 2040, 2050 in three different scenarios[2]. Each of these scenarios have different expected global installed capacities. They are called the STEPS, the Announced Pledged Scenario (APS), and the NZE. However, as they only published data for total wind energy, without splitting further into offshore and onshore wind, which is important for Japan, these data had to be adjusted. According to the IRENA report from 2020, the expected installed capacity for offshore wind will be approximately 275 *GW* and 1200 *GW* by 2030 and 2050, respectively in their own assumed Planned Energy Scenario (PES). For the more determined 1.5°C Scenario these values are increased to 494 *GW* and 2465 *GW*, respectively (IRENA, 2023a). Those two scenarios (PES and 1.5°C) from the IRENA correspond approximately to the STEPS and NZE Scenarios by the IEA. After adjusting the total installed wind capacity from the IRENA in 2022 (898.86 *GW*) to that of the IEA in 2022 (901.51 *GW*), increasing slightly the expected installed capacity by IRENA, wind energy could be split up into the offshore and onshore wind share. Data show that the offshore wind share increases from 13.36% in 2030 to 31.07% in 2050 in the STEPS Scenario. For the NZE this share increases even further to 32.46% in 2050 from the initial 18.07% offshore wind share in 2030. IRENA did not state a third scenario, which could correspond to the APS Scenario by the IEA, nor did they have values for the years 2035 and 2040. Since the APS Scenario represents the middle scenario, the added value of information is negligible when calculating the future cost range in 2050. The STEPS and NZE Scenarios are sufficient for this. To simplify the results, the APS is therefore not discussed any further. The year 2035 can also be omitted as a prediction every ten years is sufficient. The missing values for the detailed onshore and offshore wind data in the year 2040 for the STEPS and NZE Scenarios are approximated by assuming a linear share increase between 2030 and 2050. The results are shown in Table 4.2. All necessary data can now be inserted into Equation 4.3, and the results for the global total installed costs by scenario, year and technology are shown in Figure 4.1 and also in Appendix Table A5. It should be noted that in case of hydropower the mean costs between 2010-2022 were taken and is considered to stay constant. The results show that the most significant cost reduction will be achieved by concentrated solar power (CSP), though this technology will most certainly play no role in Japan.

4.3 Global Weighted Average Levelized Costs of Electricity for Renewable Energy in 2050

The calculation of the levelized costs of electricity by Equation 4.7 is more challenging, since there are four additionally variables affecting the results. While the operation

[2]see Appendix Table A15 for STEPS and NZE Scenario installed capacity assumptions

		STEPS (GW)			NZE (GW)		
Year	2022	2030	2040	2050	2030	2040	2050
Wind	902	2064	3242	3874	2742	5797	7616
Offshore	63	276	720	1204	495	1465	2472
Onshore	839	1788	2522	2671	2246	4333	5144
Offshore share %	6.97%	13.36%	22.21%	31.07%	18.07%	25.27%	32.46%

Table 4.2: Global installed wind capacity assumption based on World Energy Outlook 2023 scenarios until 2050

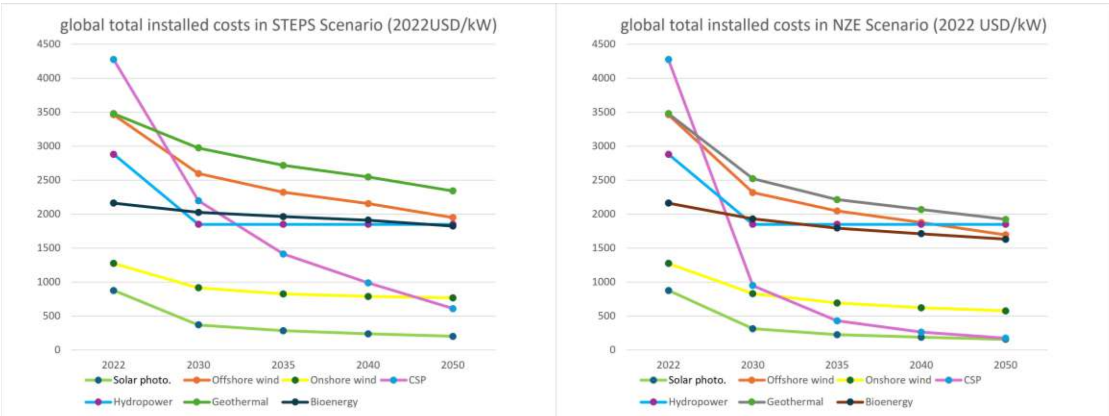

Figure 4.1: Global total installed costs in STEPS and NZE Scenario in (2022 USD / kW)

and maintenance costs, the fuel costs and the capital recovery factor are all affected by the economy, the capacity factor is also dependent on technological aspects.

4.3.1 Global Weighted Capacity Factors

The used global weighted capacity factors to calculate the global weighted average LCOE for renewable energy (see Appendix Table A4) are taken from 2022 by IRENA (IRENA, 2023b). Although the capacity factors could improve slightly in the future, these values are kept constant due to the lack of data and to simplify the calculations. This can be considered as a more conservative approach. Compared to the Japanese capacity factors, the global weighted ones are higher.

4.3.2 Global Operation & Maintenance Costs

Depending on the technology the range for the operation and maintenance costs varies tremendously (see Appendix Table A6) by IRENA (IRENA, 2023b) and are not uniformly stated. Sometimes costs are stated in relation to capacity in USD/kW and sometimes stated in relation to the produced energy in USD/kWh. These two different types of costs are included in Equation 4.7 as either $C_{O\&M_{fix}}$ or $c_{O\&M_{var}}$. It is assumed that $O\&M$ costs will remain constant. The wide range of the costs is mainly due to the different costs in countries. While $O\&M$ costs are very low in emerging and developing countries, costs are usually higher in industrialized countries. Internationally, Japan has the highest costs for all technologies. In most technologies the upper limit costs were therefore chosen for the further calculation, due to the lack of detailed information and in order to reflect the Japanese market more. This will also set the costs more conservatively (see Table 4.3). In case of onshore wind and bioenergy the operation and maintenance costs for onshore wind energy have been halved to 40.5 USD/kW, which resembles the German costs of 41 USD/kW in 2021. In case of bioenergy the average of 4% of the total installed costs of 86.5 USD/kW have been used.

	USD / kW	USD / kWh
Solar photo.	14.1	0
Offshore wind	0	0.03
Onshore wind	40.5	0
CSP	0	0.022
Hydropower	72	0
Geothermal	110	0
Bioenergy	86.5	0

Table 4.3: Global operation and maintenance costs used for calculation (2022 USD / kW and USD / kWh)

4.3.3 Global Fuel Costs for Renewable Energy

Among renewable energy technologies, bioenergy is the only one where fuel costs need to be accounted for. The issue of biofuel costs is highly complex and would require detailed and comprehensive analysis. In particular, given the current situation of energy transition, it is challenging to make accurate predictions for the distant future. In addition, there are a large number of different feedstocks, with significantly varying costs.

According to IRENA, the typical fuel costs contribute between 20-50% to the LCOE (IRENA, 2023b). To assess this, the LCOE for bioenergy, excluding fuel costs, was first calculated, with values ranging from 3.31 to 8.14 $UScent/kWh$ in the respective WEO scenarios. The associated feedstock costs ranged from 1.2 to 5.1 $UScent/kWh$. By taking the mean value over the lower and upper limits, the total fuel cost was found to range between 28.9 and 32.1 USD/MWh. Consequently, a conservative estimate of 30 USD/MWh was adopted for biofuel costs, with the assumption that this value remains constant over time.

4.3.4 Global Capital Recovery Factor

The capital recovery factor (CRF) can be calculated by Equation 4.3. It considers the lifetime n of the power plant and the interest rate r. Both data are based by IRENA (see Appendix Table A7) (IRENA, 2023b). For the interest rate, IRENA used the weighted average cost of capital (WACC). In the period of 2010-2019 the assumed WACC for OECD[3] countries and China was 7.5%, which is due to economic policies and stable regulatory lower than in the rest of the world with 10%, and it was even reduced to the latest stated 5% in 2020, to reflect more recent market conditions. Hence, the interest rate of 5% was used for the calculations.

4.3.5 Results for the Global Weighted Average Levelized Costs of Electricity for Renewable Energy in 2050

Inputting these variables into Equation 4.7 delivers the results shown in Figure 4.2 and in Appendix Table A8. On a global scale, bioenergy is the only technology, where the LCOE will face an increase in 2030 and decreases then gradually. This is probably due to the expected short lifetime of 20 years for bioenergy power plants compared to the other technologies (IRENA, 2023b). In the NZE Scenario it becomes the most expensive technology among the considered renewable energy technologies. On the contrary solar photovoltaic will lead as the most economical technology in both scenarios. The cost reduction for offshore wind energy in the STEPS Scenario is slightly higher than that of bioenergy. However, until 2050 it will not yet surpass bioenergy and remain the most expensive technology. The highest cost reduction will be achieved by CSP and will the third cheapest technology.

[3] Organisation for Economic Co-operation and Development (OECD)

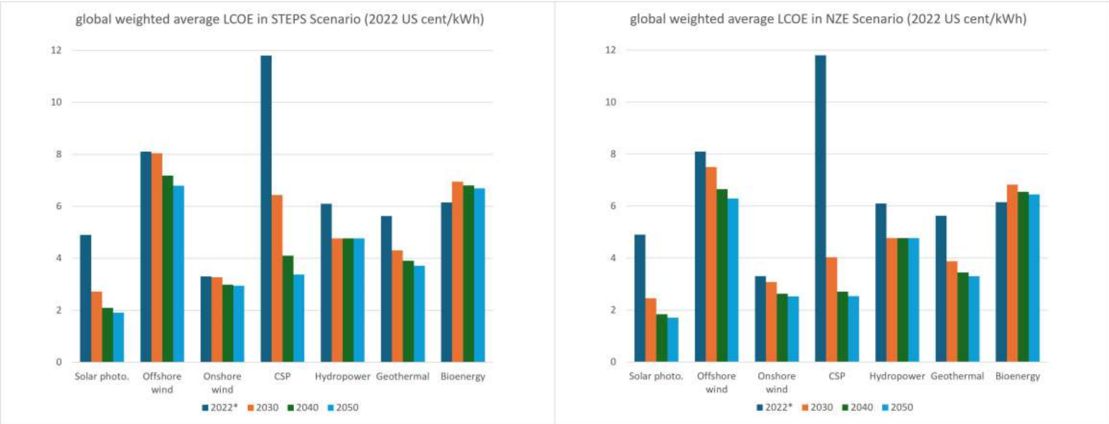

Figure 4.2: Global weighted average levelized costs of electricity for renewable energy by STEPS and NZE Scenario (2022 US cent / kWh) *(Source: IRENA, 2023b)

4.4 Levelized Costs of Electricity for Renewable Energy in Japan in 2050

Since only incomplete data the Japan-specific levelized costs of electricity for renewable energy are available in the literature, the Japanese costs were determined using the results of the previously calculated global ones. It is assumed that the Japanese costs are higher by a certain constant factor for each technology, and thus will decrease in future in dependence to the global costs. The derivation of these factors and the subsequent calculation of the Japanese costs were determined using the solution approach of Equation 4.8. The constant factor is determined by the global and Japan's levelized costs of electricity in 2022. By inserting Equation 4.7 into Equation 4.8 this leads after some reformulations to the final Equation 4.9. To solve the problem it is again necessary to determine the five variables as in the global case. However, this time these are based on the Japan-specific assumptions.

$$LCOE_{J(t)} = \overbrace{\frac{LCOE_{J(2022)}}{LCOE_{G(2022)}}}^{factor} \cdot LCOE_{G(t)} \tag{4.8}$$

where:

$LCOE_{J(t)}$ = levelized costs of electricity in Japan at time t,
$LCOE_{J(2022)}$ = levelized costs of electricity in Japan in 2022,
$LCOE_{G(2022)}$ = global levelized costs of electricity in 2022,
$LCOE_{G(t)}$ = global levelized costs of electricity at time t

$$LCOE_{J(t)} = \frac{FLH_G}{FLH_J} \cdot \frac{IV_{J2022} \cdot CRF_J + C_{O\&M_{J-fix}} + (c_{O\&M_{J-var}} + c_{J-fuel}) \cdot FLH_J}{IV_{G2022} \cdot CRF_G + C_{O\&M_{G-fix}} + (c_{O\&M_{G-var}} + c_{G-fuel}) \cdot FLH_G} \cdot LCOE_{G(t)} \tag{4.9}$$

4.4.1 Total Investment Costs in Japan in 2022

One of the major reasons to calculate the LCOE for Japan in 2050 through the global LCOE are the missing data for future total investment costs for Japan. By assuming a fixed relationship with a constant factor between the Japanese and global LCOE as shown in Equation 4.8-4.9, the needed data for the total investment costs in Japan is reduced to the year of 2022. Fortunately, these data are provided by the world energy outlook 2023 by the IEA (IEA, 2023b)[4]. Japan-specific data for concentrated solar power (CSP) were not available, since it is not used in Japan, and it will probably not be used in the future and has been therefore omitted. The total investment costs for Japan in 2022 are shown in Appendix Table A9. IRENA has also stated total investment costs for Japan in 2022. However, the data is only limited to solar and offshore wind energy (IRENA, 2023b). Comparing those two sources show nearly identical results.

4.4.2 Capacity Factors in Japan

The only technological variables are the capacity factors. The Japan-specific values are determined by using several sources. The categorization of technologies differs across sources, complicating direct comparisons and potentially affecting the consistency of the analysis. Japan specific values are only minimally represented, and show little improvements projected into the future. Hence, the factors will be kept constant. The capacity factors for Japan in the year 2050 (and also for 2022) are decided by taking various sources into account and are given in Table 4.4, which will subsequently be used for the further modeling and cost analysis (ANRE, 2021d; IEA, 2023b; IRENA, 2023b; IRENA, 2024b; OCCTO, 2022a).

[4]For solar, hydropower and bioenergy the mean value of the subtypes were created and used in the calculations.

Solar photovoltaic	13%
Offshore wind	30%
Onshore wind	25%
Hydropower	40%
Pumped storage	5%
Geothermal	70%
Bioenergy	55%
Nuclear	90%
Thermal	50%

Table 4.4: Japanese capacity factor predictions for 2050

4.4.3 Operation & Maintenance Costs in Japan

The operation and maintenance (O&M) costs for the Japan specific LCOE are similar to the ones used in the global case. This is because IRENA provided data with an inaccurate wide range of costs for each technology, without going further into detail about global weighted average costs (IRENA, 2023b). In the global case therefore (see chapter 4.3.2), the assumed costs were based on the costs assumed in Japan to reflect more the Japanese market and take a more conservative cost approach. Thus, the O&M costs for the Japanese LCOE remained the same for several technologies as in the global case (see Table 4.3). Exceptions are onshore wind energy and bioenergy, where the distinction between Japan and the global case was possible. For onshore wind energy, IRENA stated specific Japanese O&M costs of 81 USD/kW, while for bioenergy instead of 4% the upper limit of 6% of the total installed costs were taken. Although the O&M range for offshore wind energy (see Appendix-Table A6) excludes Japan, the same value as for the global case had been used nevertheless due to lack of data.

4.4.4 Fuel Costs fo Renewable Energy in Japan

As already mentioned in the global case, this subject is extraordinary complex. Since in general, feedstock costs in Japan are higher, it is assumed that the major share of the biofuel supply will be achieved by inexpensive imports. The overall average biofuel costs will hence reflect more the global costs and thus are kept the same as in the global case at constant 30 USD/MWh.

4.4.5 Capital Recovery Factor in Japan

IRENA makes country-specific weighted average capital costs assumptions only for solar, onshore and offshore wind energy in the year 2021 and 2022 (IRENA, 2023b). The mean WACC for OECD and China for these technologies are at 3.83%, 3.7% and 4.1%, whereas in Japan these values are assumed at 2.3%, 4.74% and 4.74%, respectively. While the solar WACC in Japan is lower, the wind WACC is higher. This reflects the technology preferences by the Japanese government. Due to missing data for other technologies, the weighted average capital costs for all technologies are kept as in the global case at 5%.

4.4.6 Results for the Levelized Costs of Electricity for Renewable Energy in Japan in 2050

Now that all the required variables have been determined, the LCOE for Japan in 2050 can be calculated by Equation 4.9. The results are shown in Figure 4.3 and in Appendix Table A10. At this point it should be noted that this model is not a prediction, but should deliver merely an insight into the future, and how the costs could develop. The results appear promising, despite the attempt to take a more conservative approach.

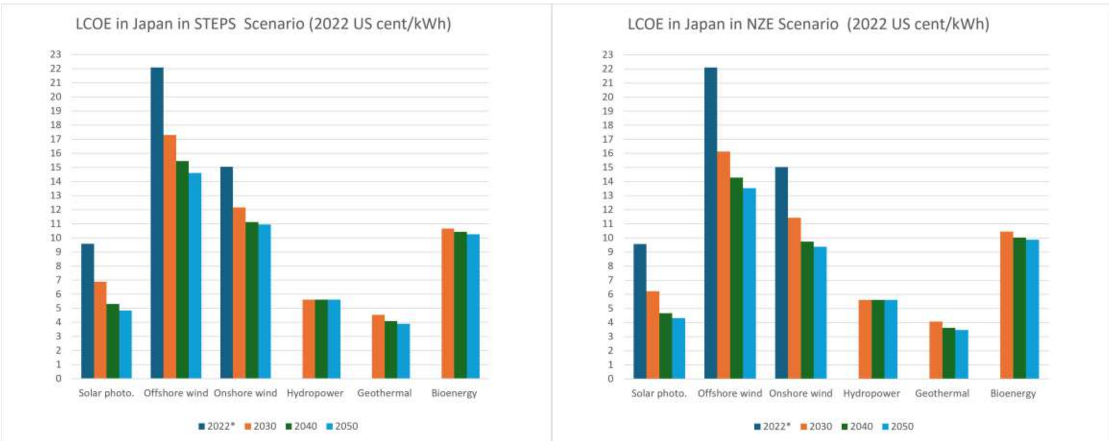

Figure 4.3: Levelized costs of electricity for renewable energy in Japan by WEO scenario (2022 US cent / *kWh*) *(Source:IRENA, 2023b)

Although the Japanese government is currently trying to promote especially offshore wind energy, this technology will yet remain with 13.5 US cent / *kWh* the most expensive in 2050 even in the NZE Scenario. However, it could be even more expensive, since offshore wind energy in Japan did not reach commercial scale yet. As mentioned before, this was the reason to use global O&M costs. No cost assumptions for this technology can be made in Japan yet. In addition, the provided O&M cost data is dominantly based on fixed-bottom offshore wind turbine data, as floating offshore wind turbines with a global installed capacity of 258 MW as of 2023, is still in developing phase and neglectable to that of the total installed offshore wind capacity of 63 GW as of 2022 (IRENA, 2023a). However, it is anticipated that the greater share in Japan will be achieved by floating instead of fixed bottom offshore wind energy until 2050 due to the steep shores. Hence that would not only increase the O&M costs but the total investment costs as well. The other influencing variables will also differ and therefore in future, when floating turbines will be deployed on a commercial scale, this technology has to be viewed separately from the fixed bottom technology.

On the contrary, although the expansion of geothermal technology with 129 GW in 2050 in installed capacity globally will be the lowest according to the NZE Scenario by the World Energy Outlook 2023 by the IEA (IEA, 2023b), this does not necessarily correlate with the global weighted LCOE in the model. At the Japanese level, the LCOE for geothermal energy will be with 3.5 US cent / kWh the most economic technology.

The many variables in addition with limited data and the long period of more than 25 years into the future makes it difficult to make realistic outcomes. In this model many variables are kept as constants. On top of that deriving Japanese costs from global average weighted costs and putting a constant factor into the calculation, where the influence of large inexpensive developing countries like China and India could distort the results, raises significant questions regarding the realism and scientific robustness of this model. However, this model merely shows how costs could develop in Japan until 2050.

4.5 Levelized Costs of Electricity for Non-Renewable Energy and other Technologies in Japan in 2050

Since, according to the Ministry of Economy, Trade and Industry (METI) a decarbonization solely on renewable energies will be unrealistic, it is necessary to determine the LCOE for other than the classic renewable energy technologies as well. It is predicted that 30-40% of the electricity demand will still be provided by nuclear and thermal energy and another 10% by hydrogen in 2050 (METI, 2021b).

The data for calculating the LCOE by Equation 4.7 for non-renewable energies and other technologies in this chapter are based on the World Energy Outlook 2023 and the Global Energy and Climate Model 2023 both by the IEA (IEA, 2023a; IEA, 2023b). In particular, Japan specific capital costs C_C and operation and maintenance costs $C_{O\&M}$

of nuclear, fuel cell, thermal technology were stated for the STEPS and NZE Scenarios until 2050 (see Appendix Table A11). The global capital costs C_C for battery and electrolyzer were stated for all scenarios by the IEA (see Appendix Table A12). The operation and maintenance (O&M) costs $C_{O\&M}$ for electrolyzers were assumed to be 3% of the capital costs (IEA, 2024a). Due to a lack of available data, the same assumption was applied to batteries. For the discount rate, the same value as in the previous chapter of 5% was used to stay uniformly. Further assumptions for each considered technology is explained below.

4.5.1 Nuclear & Thermal Power in Japan

Japan will again tremendously rely on the nuclear fleet (METI, 2021b). By doing so, the anticipated target of 30-40% supply of electricity demand, could be met by about 40 GW of installed nuclear capacity alone. The need for additional thermal power plants would be eliminated.[5] This would help significantly in the decarbonization process, and therefore in this thesis the classic thermal power plants capacity (with/without carbon capture and storage methods) can be set to zero. The current 178 GW of installed capacity at the end of 2023 for classic thermal power plants (IRENA, 2024b), however will not be dismantled but a great share will be modified to thermal power plants that will use hydrogen as fuel.

The lifetime of nuclear power plants in Japan is currently elongated to 60 operating years by the government (World Nuclear Association, 2024b). Nuclear power will remain the stable base-load supply and with exception for maintenance operating all year. The capacity factor is set to 90% or 7884 hours. Although, the fuel costs of nuclear power is comparably low and ranges globally between 0.5 - 1 cent/kWh, in Japan the fuel costs were 1.39 cent/kWh, according to an report by the IEA and Nuclear Energy Agency in 2020 (Lorenczik and Keppler, 2020). In this thesis the costs are hence set to 1.39 cent/kWh.

4.5.2 Hydrogen in Thermal Power Plants & Electrolyzer & Fuel Cells in Japan

As already mentioned the hydrogen thermal power plants derive from the classic thermal power plants and the cost assumption is therefore adapted from a mean of the various thermal power plants with carbon capture and storage technologies (see Appendix Table A11). The lifetime of these hydrogen thermal power plants is also set

[5]For further details see next chapter 5.4

to the same life expectation of gas-fired power plants of 30 years (Lorenczik and Keppler, 2020). The overall capacity factor of thermal power plants in Japan was according to the IRENA database around 50 %[6] between 2000-2021 (IRENA, 2024b). The value was therefore used for the hydrogen thermal plants as well.

Electrolyzers in Japan

The hydrogen supply will be provided by inexpensive imports and by domestic production through electrolyzers. On the technical side, the energy content (lower heat value) of 1 $kg\ H_2$ is 33.33 kWh (Bertuccioli et al., 2014), while the theoretical minimum energy to split water into hydrogen and oxygen is about 39.4 kWh per kilogram of hydrogen (Bertuccioli et al., 2014; K. Mazloomi and Gomes, 2012). Modern electrolyzers require between 50-65 kWh to produce one kilogram of hydrogen (S. K. Mazloomi and Sulaiman, 2012; K. Mazloomi and Gomes, 2012; Staffell et al., 2019), which correspond to an efficiency of about 60 - 80%. In 2050 efficiency could improve even more, but in this thesis 30% conversion losses are used, and the needed energy for the production of one kilogram of hydrogen is set at 56 kWh. In the Global Energy and Climate Model the global capital costs of electrolyzers will range between 330-470 USD/kw in the NZE Scenario to 530-740 USD/kW in the APS Scenario in 2050 (IEA, 2023a). These are the global ranges, and to reflect more the costs in Japan, the upper-limits were further considered. By assuming a lifetime of 15 years and a capacity factor of around 15%[7] the LCOE for electrolysers will range between 4.5-7.1 US cents/kWh, which produces costs of 2.52-3.92 USD per one kilogram of hydrogen. This is slightly higher than the 2.4 USD/kgH_2 assumption for Japan by the IRENA (Armaroli et al., 2022). The Japanese government anticipates similar hydrogen costs of 20 yen /$Nm3$ by 2050, which is around 2.34 USD/kgH_2[8] (ANRE, 2023b).

Fuel Cells in Japan

Fuel Cells will be the second technology to use hydrogen as a fuel to produce electricity in the electricity system.[9] Together with batteries and the pumped hydro storage technology, they will function as one of the storage technologies in the electricity systems. Fuel cells have the crucial advantage over the batteries and pumped hydro storage

[6] 48.27%

[7] The capacity factor was extracted from the model in the next chapter. This corresponds to a daily usage of 3.6 hours.

[8] 1 USD = 94.94 yen (IEA, 2023b)

[9] There are several fuel cell types, which use different fuels. In this thesis it will be reduced to fuel cells, which only use hydrogen as fuel and is not discussed any further.

technology that they do not deplete if hydrogen supply is stable. Hence they are very flexible in usage. However, as this will be probably the most expensive technology among the storage types, it will be used as a reserve technology in the electricity system. On the technical side, the electrical efficiency ranges between 35 - 60% depending on the fuel cell type (Mekhilef, Saidur, and Safari, 2012). With projection to the future, the efficiency is set to the higher value of 60% in this thesis. Usable energy is thus around 20 kWh per kilogram of hydrogen. The lifetime was assumed at 15 years[10]. The full load hours are assumed to be 5,000 hours, reflecting the expected role of fuel cells in the electricity system as intermediate load providers and grid stabilizers.

In this thesis the hydrogen costs assumption by IRENA of 2.4 USD/kgH_2 will be used(Armaroli et al., 2022). Depending on the respective technology and their efficiency, the hydrogen fuel costs per kWh (calculated by Equation 4.10) varies between 12 US cent/kWh for fuel cells to 14 US cent/kWh for hydrogen thermal power plants.

$$c_{hydrogenfuel} = \frac{2.4\,USD}{\eta \cdot kgH_2} \tag{4.10}$$

Batteries

In order to avoid the waste of the over-supply of green energy the electricity system will require to expand storage technologies. Since the potentials of the pumped storage hydro power is already limited, two other storage technologies will develop. Instead of curtailments, the energy will be stored for the long-term purpose in the form of hydrogen by electrolysis. Domestic hydrogen production however will most likely play a minor role in the hydrogen supply target of the 20 million tons per year anticipated by the government (METI, 2021b). The assumption is that a greater share will be imported by inexpensive international supply chains. Due to the high losses caused by lower efficiencies and the need for expensive electrolysers and fuel cells, alternative storage methods will also be used[11]. Currently, chemical storage methods such as lithium-ion batteries will be used, especially for short-term needs. These batteries have a much higher efficiency than fuel cells and hence are at the present more economical. Their main purpose could be the shift of the excessive solar energy during the day into the evening demand peak hours, and it could be largely introduced for instance as home batteries. The IEA emphasizes that the successful integration of

[10]based on the Fuel Cell Servers leasing durations of 10-15 years by the Company Bloom Energy (Staffell et al., 2019)

[11]However, the importance of hydrogen in the electricity system should be considered as well, as it will also be used as green substitution fuel for fossil fuels like gas in thermal power plants.

solar energy into the electricity grid will increasingly rely on the availability of robust and cost-effective battery storage technologies. This reliance becomes particularly critical when the share of solar energy surpasses 20% of the total energy mix. Unlike solar energy, wind energy integration will require storage technologies with longer duration capabilities, potentially spanning over weeks or even entire seasons. In this context, hydrogen production through electrolysis emerges as a promising solution (IEA, 2024b).

The battery efficiency depends on the used technology and charging-discharging rate. Among various storage battery technologies, lithium-ion batteries are experiencing the fastest growth in terms of adoption (IEA, 2023b). Despite lithium-ion batteries generally offering higher overall efficiencies (Farhad and Nazari, 2019), a conservative total efficiency $\eta_{Battery}$ value of 90% is used.

The ratio of the chargeable energy content of a storage battery to its capacity, often referred to as "duration" or "discharge time," varies significantly depending on the battery's intended use and technology. For instance, residential consumer batteries typically have a capacity of 5 kW and a storage size of 13.5 kWh, corresponding to a discharge time of 2.7 hours ($13.5kWh/5kW = 2.7hours$). Large-scale battery storage systems tend to have longer durations, like the four hour battery farm of the electricity supplier Southern California Edison with 20 MW and 80 MWh. According to literature, discharge times for battery systems can range from 0.39 to 10 hours depending on the batteries purpose. Batteries with short discharge times are used for frequency regulation, while the ones with longer durations are used for load shifting (IRENA, 2019a; IRENA, 2019b). For this thesis, a discharge time of three hours is assumed, implying that the energy storage size is three times the installed capacity.

The IEA predicts global capital costs C_C between 130 USD/kWh in the NZE Scenario to 140 USD/kWh in the STEPS Scenario in 2050 (IEA, 2023a). As there is no further detailed information about the cost assumption in Japan, the global costs were accepted. If battery degradation and the depth of discharge is neglected, a lifetime assumption of 10 years (Lorenczik and Keppler, 2020) and one full cycle per day is assumed, the Levelized Cost of Storage (LCOS) of batteries[12] can be calculated by Equation 4.11 and corresponds to approximately 6.3 and 6.8 US cent/kWh in the respective scenarios.

$$LCOS_{Battery} = \frac{C_C \cdot CRF + C_{O\&M}}{\eta_{Battery} \cdot N_{cycles}} \tag{4.11}$$

where:

N_{cycles} = Number of Cycles per year (assumed at 365)

[12] The LCOS is the LCOE, where charging costs are excluded (Lorenczik and Keppler, 2020).

4.5.3 Results for the Levelized Costs of Electricity for Non-Renewable Energy and other Technologies in Japan in 2050

The results of the LCOE for other than the widely used renewable energy technologies is shown in Figure 4.4 and is also summarized in Appendix Table A13, while the assumptions about lifetime and full load hours of the individual technologies is also given in Appendix Table A14. The World Energy Outlook does not state any further details about pumped hydro storage costs. Therefore the LCOE of the classic hydro power was adopted as LCOS. Figure 4.4 shows that all hydrogen technologies will have high costs. Even though the expectation that fuel cells will remain the most expensive technology, due to the high hydrogen fuel costs and consumption, the use of hydrogen in modified thermal power plants shows higher costs. The underlying reason could be that the costs of these kind of power plants derive from the fossil fuel based thermal power plants, where development and subsequently cost decreases is in stagnation. Additionally, if carbon capture and storage is included, then the costs become significantly high. Although hydrogen does not produce carbon, the costs could be very similar to that of fossil fuel based thermal power plants with carbon capture technology and were hence adopted. If the costs by carbon capture and storage were neglected, and therefore the hydrogen thermal power plants is assumed to be as cheap as classic thermal power plants, the costs would be decreased by 5-6 US cent/kWh to an LCOE of approximately 18 US cent/kWh.

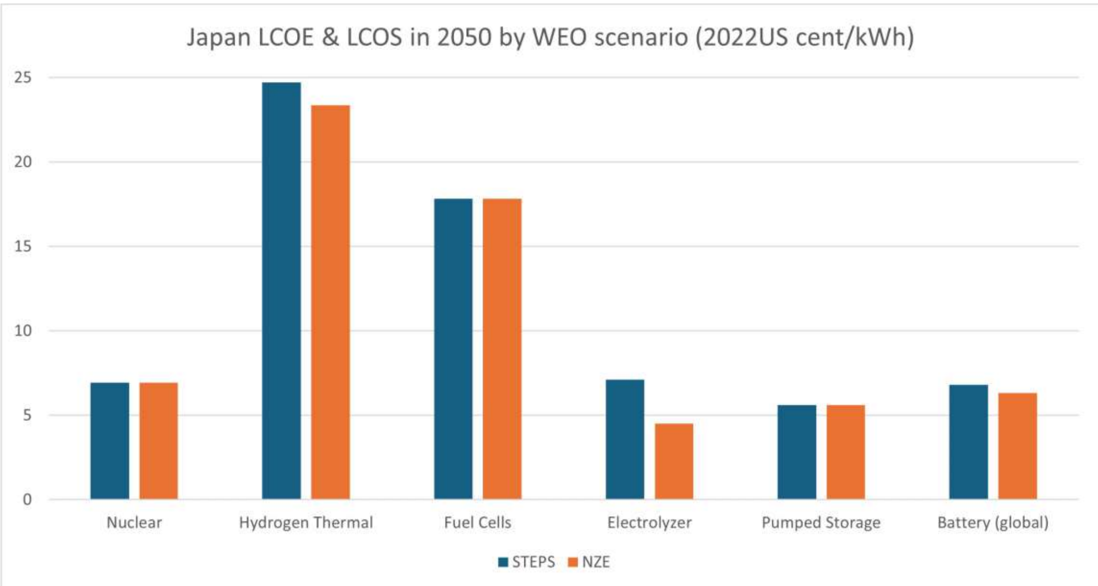

Figure 4.4: Levelized costs of electricity and storage in Japan in 2050 by WEO scenario

5 Electricity Supply and Demand

In this Chapter the electricity supply and demand of Japan at the present as well as the situation in the future in 2050 will be discussed. The foundation will be historical data between 2017-2023 from the Renewable Energy Institute (REI) of Japan (Renewable Energy Institute, 2024). The acquired data was imported and evaluated with the mathematical programming software MATLAB. Based on the recent strategy plans of Japan, a model for 2050 was created, while taking Japan's estimated realizable potentials for renewable energies and the economic side as well into account (see Chapter 3).

5.1 Implementing and Adjusting the Data into Matlab

The available data by REI reaches back to the beginning of the fiscal year in 2016 in April and includes hourly data until up to date. The most recent data is updated up to two months before the current month. However, there is missing data in the year 2022 from January to March, which is probably due to the change from calendar year to fiscal year, which starts in April in Japan. To make data comparable, only calender years with a full hourly data set is taken. Namely, the years 2017-2021 and 2023. Additionally, the data for February 29 of the leap year in 2020 is filtered as well. For easier future references in this chapter, instead of writing "2017-2021 and 2023" it will be addressed as "2017-2023" well knowing that data for year 2022 is missing. The hourly data in GW represents the mean power in GW in the specific hour, but also the energy in GWh as well, as this mean power is related to exactly one hour. This makes further calculations reasonably uncomplicated. As already mentioned, the available data is based on hourly values for all Japan of:

- Date
- Time (hour of the day)
- Nuclear power supply in GW
- Thermal power supply in GW
- Hydropower power supply in GW
- Geothermal power supply in GW
- Biomass power supply in GW

- Solar power supply in GW
- Wind power supply in GW
- Pumped storage (pumping up) in GW
- Pumped storage (generation) in GW
- Import in GW
- Export in GW
- Solar power curtailment in GW
- Wind power curtailment in GW
- Demand in GW
- Japan Electric Power eXchange day-ahead market price in yen/kWh

Although there would have been even more detailed regional data for each of the ten areas, this was not further considered and only the data for the entire country was taken into account. It was also neglected, on which day of the week each year starts.

Normalizing Supply for Comparison

As demand increases with time and therefore also the needed supply, the installed capacity increases as a consequence as well. To make the data of the different years for the supply comparable, it is hence related to the installed capacity for each technology. The information for this is taken mainly from the IRENA online database (IRENA, 2024b). However, the available data for the installed capacity at the IRENA database is limited to one value for each year and technology. For example, in 2017 and 2018 the installed capacity for Solar photovoltaic is 49500 MW and 56162 MW, respectively. The stated value by IRENA is the installed capacity at the end of the year, but simultaneously also represents the installed capacity at the beginning of the next year as well. The installed capacity values for each hour throughout the year were assumed to increase or decrease in a constant way from start to the end. Therefore, for this transition, a linear approximation as in equation 5.1 was made. This creates hourly data for the installed capacity for each technology. Visualized, this assumption looks like a ramp, whereas in reality it should look more like many stairs with different step heights. However, due to the lack of additional data the linear approximation has been used, and minor falsifications of the results accepted.

$$y = k \cdot x + d \tag{5.1}$$

The Research Energy Institute (REI) only published summarized data for the technologies. For instance, unlike IRENA, where there is a different set of data for onshore and offshore wind power, REI only has cumulative data for wind energy altogether. Therefore, the IRENA data had to be adjusted to fit the REI data, by summarizing different technologies together and loosing important information.

With the data for installed capacity for each technology and year on an hourly basis, the given data of the supply could be normalized by relating it to the capacity and this creates values between 0 and 1, in short from 0 to 100%. This makes data for the different years not only comparable, but it can be further analyzed to make standard profiles and other assumptions.

Exception for Nuclear Power

The data by IRENA reflects the "installed and connected" data. However, this situation is special for the nuclear power fleet in Japan. After Fukushima the entire nuclear power fleet was shut down and after evaluation some of these power plants were even entirely taken from the grid. From the remaining fleet only a third of them are operating again[1], while two thirds of the fleet is still shut down. IRENA's data represent the remaining fleet ("connected to the grid") but not the actual operating reactors, which is why a subsequently calculated capacity factor with this data would distort the technical potential of a nuclear power plant. Further calculations would become irrelevant. Therefore, an exemption was made by using other data for the installed capacity of nuclear power. The additional data was taken from the world nuclear association, where the month of the restart for each individual power plant is stated (World Nuclear Association, 2024b). In Japan's case until the end of the year 2023 twelve reactors have gone in operation again. It is assumed that the capacity is installed at the beginning of the stated month. Unlike the other technologies, a more realistic stair-shaped implementation for the installed capacity could be made. Later results showed that the supply by nuclear power exceed at some points the 100% mark. This could have several reasons. Tests with other installing methods, like a linear increase of installed capacity (ramp-shaped) in the month previous to the stated restart month or even an instant (step-shaped) restart one month earlier still showed exceeding values. The most likely reason for these impossible values could be therefore, that there are reactors other than the stated reactors contributing to the grid supply. These could be power plants, which have not officially restarted yet, but may be in testing phase and hence already active. At this stage, further considerations were not made and the first model with the sudden increase of installed capacity at the beginning of the stated month implemented into the model.

[1] as of July 2024

5.2 Visualizing the Data

Importing the data into MATLAB enabled a visualized analysis for the demand and supply situation between the years of 2017-2023. Furthermore, this allowed to evaluate the cultural, industrial and climate influences as well as the behavior of the population in reference to the energy demand and supply.

5.2.1 Electricity Demand between 2017-2023

On the demand side the actual electricity demand in the period between 2017-2023 ranged from 58.7 to 164.8 *GW*. Figure 5.1 shows the daily mean demand in between the years 2017-2023. Throughout each year the demand dropped in three occasions. The first drop is at new year, where most businesses close between the first three days of the year although these are not official holidays. The second drop is in the so-called "golden week", where many holidays follow each other. It starts with the Showa day on April 29 and ends with the children's day on May 5. Workers usually have to take only two extra days depending on the year to get a full week of vacation, which is widely used by workers. The third drop is due to the Obon-Festival, which lasts three days, and usually is between August 13-16. These three drops show the importance and the effect of the demand by the industry.

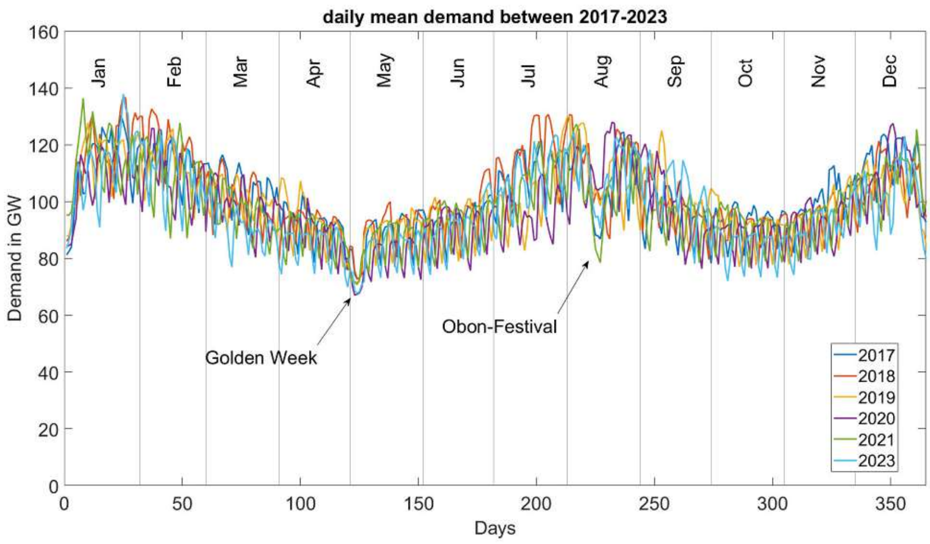

Figure 5.1: Demand in Japan with daily average values between 2017-2023 in *GW*

A more seasonal profile of the demand can be seen in Figure 5.2. It shows a comparably higher electricity demand in the hot summer and cold winter month, while the lowest demand is in May, followed by April and October, where the weather conditions are optimal. Additionally at the beginning of May is the earlier mentioned Golden Week holidays. The lowest demand of the individual years between 2017-2023 falls into this week and mostly on the last day on May 5 (the children's day) with the absolute lowest peak in 2023 with 58.7 *GW* at 01:00 *am*. On the contrary, the highest demand peaks of each year was always in the summer month between July 27 – August 24, with the absolute highest demand peak in 2020 on August 20 with 164.8 *GW* at 02:00 *pm*. This could be due to the use of electric air conditioning for cooling, which is standard in Japan. However, if Figure 5.1 and 5.2 are examined more closely, it can be seen that in general the electricity demand is higher during the winter period rather than in the summer period. This is because central heating is largely unknown in Japan and air conditioning units are gradually being used for heating as well, which are replacing the use of mobile oil heaters without a proper exhausting system. Building insulation, especially in non-modern single-family homes, has not been common practice until now (Pohl, 1996). Therefore, the electricity demand increases drastically in the winter months. According to the Japan statistical yearbook 2023, the coldest month were January, followed by February and December (Statstics Bureau Japan, 2023).

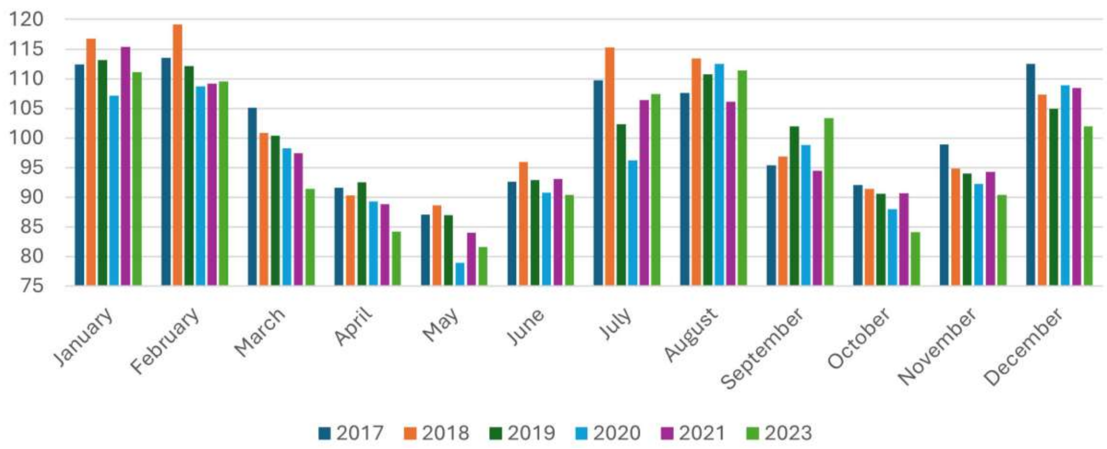

Figure 5.2: Monthly average demand in Japan between 2017-2023 in *GW*

The major difference between the electricity demand during winter and summer can be seen in Figure 5.3, where the daily profiles of the month of January and July of the years 2017 and 2023 are representatively shown. While in July there is only one load peak in the middle of the day and comparably low demand during the night, in January, additionally to two daily peak loads in the morning and evening, the electricity demand stays higher during the night than in July. In general, in all daily profiles there is a sudden drop during noon on working days. This could correspond to the lunch break and disciplined energy savings behaviors.[2]

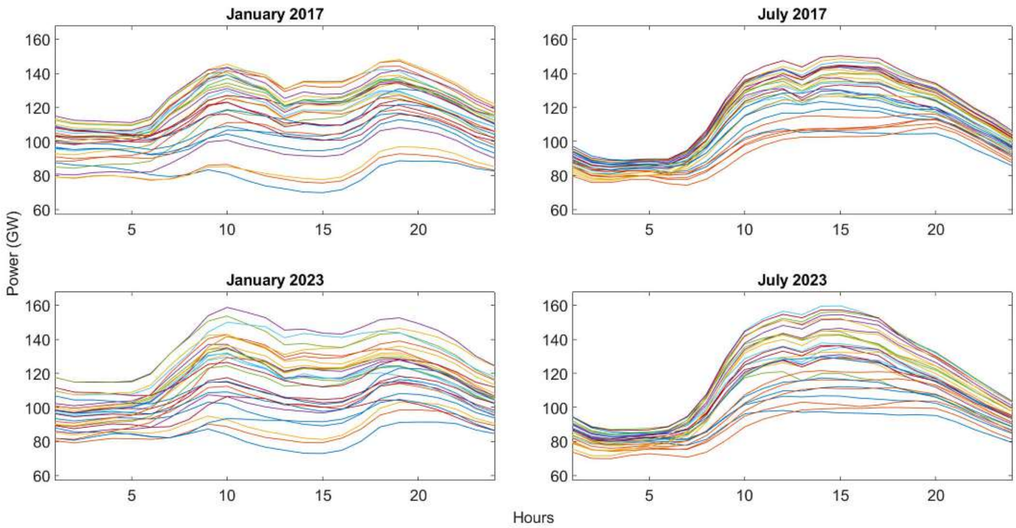

Figure 5.3: Daily profiles of electricity demand in January and July of the years 2017 and 2023 in *GW*

During the period between 2017-2023 the total electricity demand peaked in 2018 at 897.93 *TWh* and shows a slight decrease by 4.26% to 851.24 *TWh* in 2023 compared to 2017 as can be seen in Table 5.1. However, it is difficult to ascertain further trends as many factors like recent geopolitical and economical events among other things had a considerably impact in the observed period and will continue into the future.

2017	2018	2019	2020	2021	2023
889.08	897.93	877.39	853.37	867.27	851.24

Table 5.1: Total electricity demand between 2017-2023 in *TWh*

5.2.2 Electricity Supply in 2017-2023

On the electrical supply side, the most influential components are the weather conditions as well as political decisions. Industrial and cultural influences play a minor role.

[2]„working days noon drop" würde man in einer weiteren Figure sehen, die ich aber nicht eingefügt habe. Ich wollte es kurz halten. Falls gewünscht, kann ich das aber einfügen.)

Exemplary, all 365 daily profiles of the electricity supply related to the installed capacity of each technology in 2023 are shown in Figure 5.4. The profiles are corresponding to the usage level in percent (between 0-1 or 0-100%)[3] or more precisely to the capacity factor. Nuclear, geothermal and biomass power have the most constant profiles, while the usage of thermal power and hydropower rise in the morning and evening hours to meet peak demands. Solar and wind energy show very diverse profiles and hence the lack of reliability of both technologies. As solar power is fixed to the sunlight it contributes only during daylight and the height of the mountainous profiles depends on the two major factors: the weather and the season as the declination of the sun changes throughout the year. Wind power shows the most uncertain behavior, but the average usage level exceeds these of solar power. The pumped storage hydropower is used as the systems battery, charged throughout the day, and mainly used in the evening peak hours.

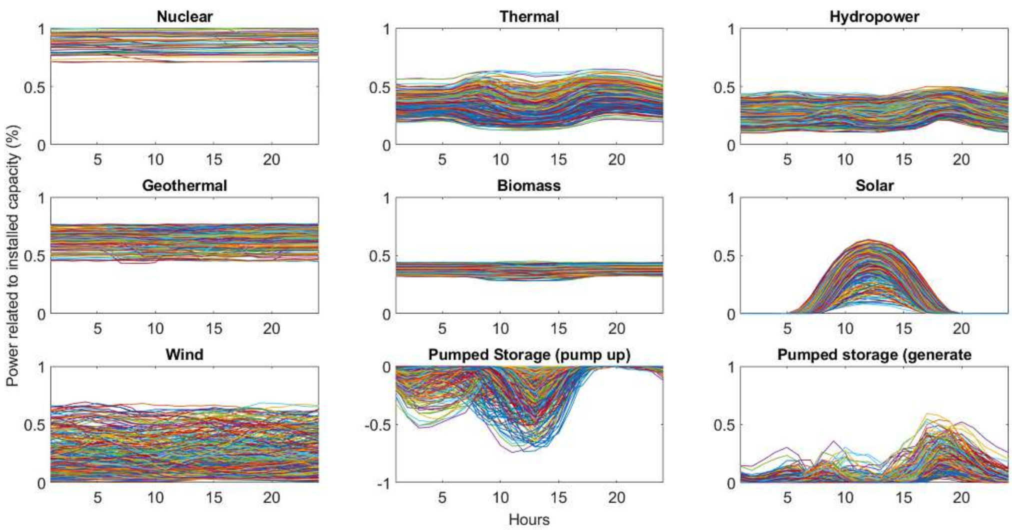

Figure 5.4: Daily profiles of electricity supply related to installed capacity in 2023 by technology

Figure 5.5 shows the average daily profiles of electricity supply technologies, obtained by averaging hourly values over all days within each year from 2017 to 2023. While the utilization of thermal power declined, almost any other technology increased. The only exception is solar power, which stayed constant. Three things can be driven out of

[3] As already mentioned in the case of nuclear power the values exceed in some cases the 100% mark, probably due to additional operating nuclear power plants other than the officially restarted ones, and therefore falsifying the assumed installed capacity at certain points of time. However, this error is neglected and accepted in the model, later used in this chapter.

this figure. First, there is an evidently shift to more environment friendly technologies. The second and third point are connected to the capacity factor and the usage rate. The increases in the figure can mean that either the technology has advanced and therefore increased its technological reachable capacity factor or that the usage rate has just risen, which means that the technology has not been used to its maximum nominal capacity. Usually, power plants are not operated in their upper limit. This allows them to adjust the supply according to the necessary demand in both direction: increasing or decreasing supply. However, the exceptions are wind and solar power, which outputs is severely depended on the weather conditions and unpredictable. Therefore, in case of wind power the increase will most likely show the technological advances. The capacity factor for solar power remained constant, which is due to the matureness of the technology but also due to the usage already to its technological limits.

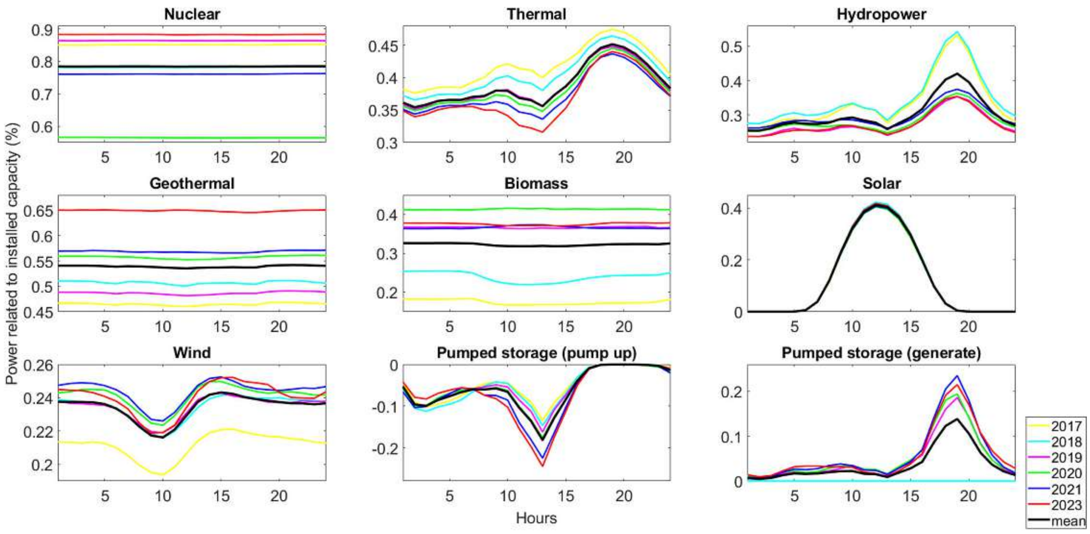

Figure 5.5: Daily average profiles of electricity supply from different technologies, calculated per year, during the period 2017–2023.

In addition to the weather conditions both technologies show strong seasonal profiles as shown in Figure 5.6. While wind power has its most potential in the winter months, it drops during the summer to less than halve of the value. Solar power on the contrary reveals almost the opposite. However, the difference between the season profile for solar power is not as eminent as for wind power and clearly demonstrates that local conditions in Japan for solar power are beneficial.

The uncertain supply of solar and wind power makes them, from the perspective

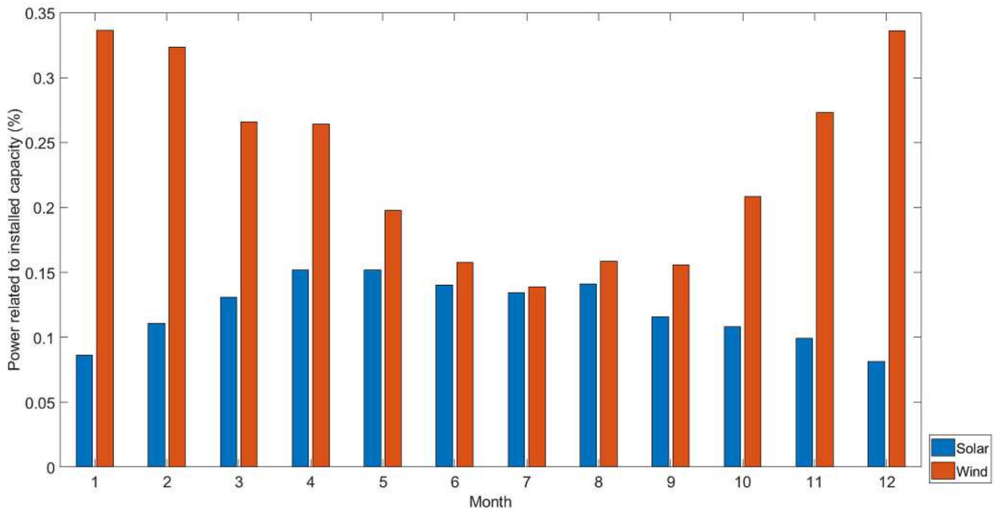

Figure 5.6: Monthly mean profiles of solar and wind power related to installed capacity between 2017-2023

of regulating the supply to the demand, unviable. In this perspective the restart of the more reliable nuclear power plants had effected the supply on both renewable technologies. With growing installed capacity of solar and wind power to the restart of nuclear power plants curtailments increased from 0 GWh in 2017 to 1920.6 GWh (1867.3 GWh for Solar and 53.3 GWh for Wind) in 2023 as shown in Figure 5.7. Most curtailments occurred during springtime when demand was the lowest. This period would offer the best opportunity to save excessive energy if long-term (annual storage) battery technologies would be available. Curtailment rules already have been implemented by OCCTO to favor low emission technologies and thus to force EPCOs to minimize solar and wind curtailments (OCCTO, 2022a). Although solar power is at the present dominant and therefore curtailments from wind power is almost neglectable compared to these of solar power, both technologies in combination could be more evenly contributing to the electricity supply throughout the year, if the shift to (more wind power) renewable energy continues.

5.3 Electricity Demand in 2050 in Japan

According to the green growth strategy electricity demand will increase by 30-50% in 2050 due to electrification. The origin of this information is based on the prognosis

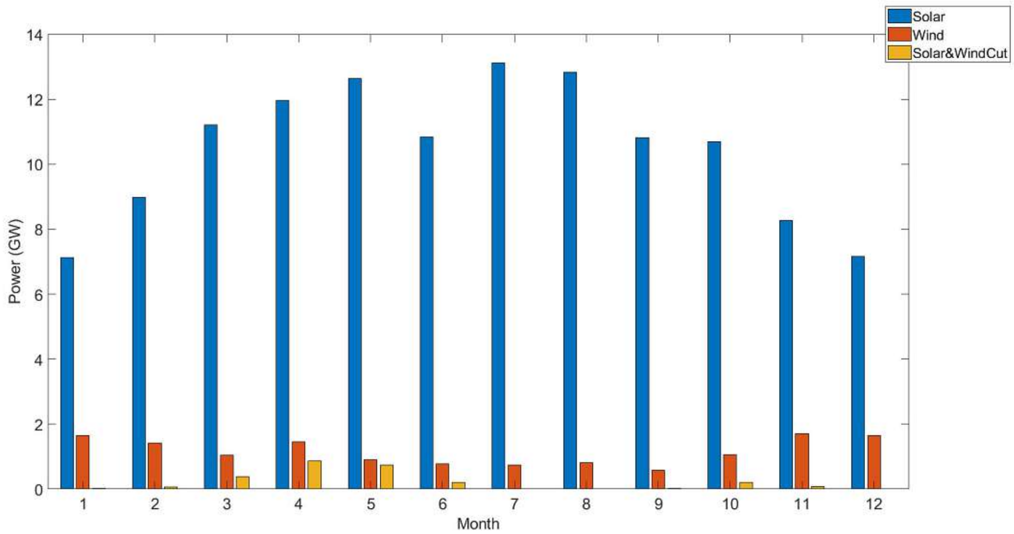

Figure 5.7: Monthly profiles of solar and wind power and their curtailments in 2023

made by the Research Institute of Innovative Technology and Earth (RITE). However, RITE did not state any further information about the assumed conditions in 2050. It is difficult to make any verifications as many influential factors have to be considered. For example, given the current situation in Japan, aging and depopulation are two serious issues. The United Nations predicts a depopulation by a medium of 20.3 million to 103.7 million with a medium age of 55 years for Japan in 2050. Around 34.1-41.6% will be older than 65 years (UN, 2024) and therefore in retirement (OECD, 2023). A Japanese study showed a depopulation decrease between 8-17%, and that this will have a great impact on the industry (Li et al., 2024), like already seen not only in holidays like the Golden Week and Obon-Festival, but also the lunch break, which decrease the electricity demand tremendously. With the aging population and a greater share in retirement, this could be lowering the demand greatly. The different scenarios of the study projected the total energy demand range between a 25% increase from the level of 2015 to a decline of 18% from the level of 2020 (Li et al., 2024). Another study predicts that load profiles will change in magnitude and shape, as high electricity activities will decrease about 8% in favor to more low electricity-density activities, like sleeping (naps), since unemployed persons sleep on average 67 minutes longer a day. On the contrary, travel distances are supposed to decrease and that could promote electric vehicles (EVs), as shorter distance eradicate the current EV problems of range, resulting in an increase of the entire electricity demand (Zhang et al., 2021). It is clear that depopulation and aging alone could nullify the rise of electricity demand due to electrification. However, the ongoing trend of increasing household numbers due to the transition from nuclear-family households to single households (Statstics Bureau Japan, 2023) or possible future technological advances for energy savings and other criteria have not been considered yet. Since these are only examples of the complexity of future electricity demand predictions, in this thesis, it will focus on the statement of the green growth strategy with the highest electricity demand increase of 50%. As for the lower range end, the current electricity demand of 2023 will be taken. The demand for 2050 will therefore predicted to be in the range between 851 to 1,276 TWh.

5.4 Japan's Vision of the Power Plant Fleet Composition in 2050

Based on discussions among experts from the energy sector, the government stated their prediction for the composition of the energy mix in the green growth strategy. As the decarbonization on renewable energy technologies solely will be unrealistic they predict that the electricity demand will still be satisfied by 30-40% by nuclear and thermal energy with carbon capture methods. Another 10% of the power generation will be by hydrogen and ammonia. The remaining 50-60% will be covered by renewable energy resources. In the remaining non-electricity energy demand hydrogen, methanation, synthesis fuel, biomass and fossil fuels will be used with carbon capture technologies as possible. However, there is no more detailed composition for the actual power plant fleet mix (METI, 2021b). The only official targets are made for offshore wind energy and hydrogen. For offshore wind energy only targets for 2030 and 2040 are set to 10 GW and 30-45 GW, respectively (METI, 2020). There are plans by the Japanese wind power association to even enlarge the offshore wind power fleet to 90 GW and additional 40 GW onshore wind power by 2050. Although these numbers are not official targets by the government, it shows the ambitions by the private industry and the potential, and it could mark actual realizable targets within the period. As for hydrogen the supply amount target is set to 3 million tons per year by 2030 and 20 million tons per year by 2050 (ANRE, 2021c). With the deployed international supply chain, the assumption is that this target will be reached primarily by imports.

Currently, the only available detailed future targets are these for 2030, as already mentioned in chapter 3.6 in Figure 3.10. The figure shows the current priority set by the government and should therefore serve as the basis for the long-term assumption for 2050, while respecting the limitations of the individual potentials by each energy technology. If a linear growing trend of the renewable share in the total power mix from the base year 2021 is assumed, coupled with the two different renewable share targets of 50% and 60% by 2050, this leads to the individual percentual share targets for each technology, which are summarized in Table 5.2. In conjunction with the demand range prediction of 851 to 1,276 *TWh* in 2050, this leads to four different capacity goals. However, this would first lead to capacity goals that exceeds the limits of the potential in hydropower and secondly the specific wind power target would not be met. Therefore, additional assumption had to be made to adjust the individual targets. The results are presented in Table 5.3. Currently, the nuclear power fleet could reach up to 31 *GW* if fully restarted. Additional 15.7 *GW* were in planning in the last decade but deferred due to the Fukushima incident. Recent decision for the continuing of nuclear power in general will most likely lead to the construction of those planned power plants and certainly some more. By 2050 several older reactors on the contrary will be shut down and in total it could lead to a fleet of approximately 35-40 *GW*. To favor nuclear power over thermal energy the upper assumption of 40 *GW* was implemented. The potential of pumped storage is considered depleted and the target is set to the most recent value of 2023, while hydropower has a little potential left and is set to 30 *GW*. The decreased share of those two technologies will be seized by wind energy ranging from 24.2 *GW* to 77.65 *GW*.

	power generation mix*		2050	
	2021	2030	RE min	RE max
Nuclear	7%	20%	40%	30%
Thermal	72%	41%		
H2/NH3	0%	1%	10%	10%
Hydropower	7.50%	11%	14%	17%
Geothermal	0.30%	1%	1%	2%
Bioenergy	3.20%	5%	7%	8%
Solar	8.30%	16%	21%	25%
Wind	0.90%	5%	7%	8%
RE-share	20.20%	38.00%	50%	60%
Total (*TWh*)	1032.7	934		

Table 5.2: Electricity generation share composition assumption for 2050; *(based on Source: ANRE, 2023a)

Hydrogen will be the substitution technology for thermal energy It will most likely be used in modified thermal power plants, and thus the same capacity factor of 0.50 was adopted for the hydrogen technology. This leads with a 10% generation share target to a capacity up to 29.15 *GW*.

RE-share	**minimum share (50%)**				**maximum share (60%)**			
Demand	d_min	d_max	d_min	d_max	d_min	d_max	d_min	d_max
	2050 (TWh)		2050 (GW)		2050 (TWh)		2050 (GW)	
Nuclear	245	245	40	40	245	245	40	40
Thermal	95	265	22	61	10	138	2	31
H2/NH3	85	128	19	29	85	128	19	29
Hydropower	105	105	30	30	105	105	30	30
Pumped hydro	10	10	22	22	10	10	22	22
Geothermal	9	13	1	2	17	26	3	4
Biomass	60	89	12	19	68	102	14	21
Solar	179	268	157	235	213	319	187	280
Wind	64	153	24	58	98	204	37	78
RE total	426	638			511	766		
Total	851	1277			851	1277		

Table 5.3: Capacity and generation share in 2050 for different RE-share and demand predictions

5.5 Creating the Model: Implementing a Power Plant Fleet into MATLAB for 2050

Supply and Demand naturally never matches, as the demand always changes according to how people and the industry needs it. Therefore, adjusting the supply to the demand is inevitable. There are mechanisms to manipulate the demand by encouraging a change in behavior of the industry or end-user. This mechanism is called demand side management and a simple method to do so is by influencing the market price. On the supply side on the contrary, supply is adjusted accordingly to the demand and usually it follows the economical principal of the merit order. This means that the basic supply order of the power plant fleet is oriented by the levelized cost of electricity (LCOE) of each power plant. Subsequently this means that the total market price is derived by the highest LCOE of the last power plant that is operating to meet the demand. If the demand is lower, the most expensive power plant stops operating and is therefore dismissed from the supply system. This continues until supply meets the demand. A new cheaper market price will adjust itself to the highest LCOE of the last contributing power plant in the system. Political and economical instruments can be used to influence this merit order. For instance, by introducing a CO2-price to make a technology based on its environmental impact more expensive or by supporting certain technologies by subventions and Feed in Tariffs to make them less expensive. These are only examples of the many mechanisms that could be used to influence supply and demand.

The core objective of this thesis is the decarbonization of Japan's electricity system by 2050 in consideration of Japan's renewable energy potentials as well as the economic perspective. However, as two major renewable resources (solar and wind energy) are considerably volatile, a simple capacity substitution from conventional coal power plants to solar or wind farms is not easily possible, as the production in these farms cannot be securely predicted at any particular moment. Hence, merely by guessing the needed capacity for 2050 by Table 5.3 is insufficient. Additionally, the needed storage technologies have not been considered yet either. For this reason, a model was created in the mathematical Software MATLAB, to simulate the demand and supply situation in 2050. The results were presented in different scenarios with different capacity goals for the considered technologies.

5.5.1 Prepartions for the Model

As mentioned at the beginning of this chapter, the demand and supply profiles in 2050 are based on the historical data between 2017-2023 from the Renewable Energy Institute of Japan (REI). These data were used to create scalable standard profiles in the first step.

On the demand side, the second and final step was to scale up the profile by implementing the demand predictions for 2050 as described in chapter 5.3. The prediction stated an increase of 30% to 50% as of today[4]. In summary, the real demand of the latest year of 2023 by REI was used as the basis standard profile. To make sure a full decarbonization will be reached in 2050, the prediction with the highest demand for 2050 was implemented into the model. The demand profile of 2023 was hence scaled up by a 1.5 factor. The needed total annual energy corresponds to 1276.86 TWh.

The objective of the supply side is to create an environmental and economic power plant fleet. This primary means a shift from the conventional thermal power plants to more renewable energies. However, as already mentioned the unpredictability of mainly solar and wind energy makes a straightforward substitution unachievable. Hence, standard profiles for solar and wind were created in a similar procedure to that of the demand. The flexibility of the other technologies allowed them to be implemented directly into the model without the need of creating such profiles in advance. Their purpose is to adjust the supply to meet the necessary demand. The only important value for these technologies are the amount of the respective installed capacities.

For the simulation data in 2050 for the solar and wind energy profiles, the real hourly power values of the REI data in each year were used. These values were first related to the installed capacity, and then a mean value for each hour of the year was made for the

[4]This was actually stated in 2021 by METI in the Green Growth Strategy (METI, 2021b).

period between 2017-2023. The results are two 8760 x 1 vectors, which represents the standard profiles for both technologies, respectively. Since these two standard profiles were related to the installed capacity, they can be scaled up by any amount of desired capacity. This allows to implement the necessary capacity targets from Table 5.3 and generate different scenarios.

The last preparation, before creating the algorithm for the model, the capacity factors for all technologies had to be adjusted. The capacity factors resulting from the data of the REI were different than those already used in the model in Chapter 4, where the levelized cost of electricity for 2050 had been calculated. While first ones show real capacity factors from the past years (2017-2023), the ones used in Chapter 4 include the capacity factor predictions for the future. The supply of solar and wind energy can be scaled up by adjusting the anticipated capacity factor. This is made possible by the use of predefined generation patterns, which simplify implementation. However, this approach is not readily applicable to other technologies, whose profiles emerge dynamically from the model. The resulting capacity factor, which reflects both the utilization rate and technological progress, is directly determined within the model framework. Notably, the model inherently favors base-load technologies such as nuclear and geothermal energy, allowing them to operate at near-optimal utilization levels. The integration of technological advancements for the remaining technologies into the model is highly uncertain and subjective, particularly in the absence of a detailed analysis and comprehensive modifications to the simplified model. Consequently, it has been omitted.

The only limiting factor within the model is the operational range, which is derived from REI data and also serves as a proxy for efficiency. To define this range, the maximum and minimum values from REI data were determined for each technology and then normalized to the installed capacity, resulting in values ranging from 0% to 100%. For instance, according to REI data, the solar energy supply on July 22, 2023, at 12:00 PM was 46.3 GW. When related to the installed capacity of 89 GW (as reported by the IRENA database), this corresponds to an operational efficiency of approximately 52%. Using the same approach, the minimum and maximum values of all technologies (excluding solar and wind energy) were identified over the observation period 2017–2023 and subsequently defined as their potential operational ranges, which will be discussed in more detail in chapter 5.5.2.1.

If, instead of using these minimum and maximum values, the average of all observed values were applied, this would correspond to the current capacity factor. For solar and wind energy, this method was used to adjust the generation profile accordingly, effectively modeling a hypothetically increased energy supply that reflects advancements in these technologies. However, applying the same approach to other technologies would lead to physically implausible distortions. For instance, with an installed nuclear capacity of 40 GW, this method would imply a supply of 45 GW per hour, resulting in a capacity factor exceeding 112%, which is physically impossible. Therefore, the consideration of technological advancements for these technologies has been omitted.

5.5.2 The Algorithm

As already mentioned, the technologies, other than solar and wind energy, will be used to balance the supply to meet the necessary demand in each hour. Usually, these technologies have the ability to change the power output. However, there are technologies that are faster than others and these are called load-following power plants. Those are primary used to balance the supply to the demand in short-terms. On the contrary, slower technologies like nuclear and geothermal are the base-load power plants, where a stable almost constant supply is desired. Their output is only changed if the fluctuation in the demand is atypical sever. Preferably, a high as well as a constant usage is aimed, due to economic reasons. Recent global trends although show that former slow base-load technologies become increasingly adaptable to change. This change is linked to the increasing share of volatile technologies and the subsequent necessity for load-following ability. Even the slowest technology, the nuclear power, can nowadays be used to follow the load (IAEA, 2018). Nevertheless, Japan will most likely keep the conservative usage for these base-load technologies. The evidence is shown in the priority dispatch rule by OCCTO (Ichimura, 2020)[5], where rather instead of changing the output for nuclear, hydro or geothermal power, curtailments of the volatile technologies are considered.

5.5.2.1 Load Following Ability and Operation Range of Power Plants

Each technology has its own speed to follow the load. The model uses only hourly values. Thus, the speed can be neglected, or seen as "infinitely fast" in the model, since even the slowest technology, nuclear, can adjust its output by up to 1.5-3%[6] per minute of the rated capacity (Lokhov, 2012). This corresponds to a changing rate of at least 90% and up to 180% per hour. Additional to the speed of change, the operation (working) range between maximum load to minimum load, has to be considered as well. For nuclear power the minimum load is approximately 50% (IAEA, 2018). This means a maximum operation range of 50% is tolerated in order for the power plant to operate normally. Otherwise, a shut-down of the power plant would be necessary,

[5] see Figure 3.7 in Chapter 3.4

[6] Changing rates lower than 1.5% are considered slow power plants. These are used for example in France (Lokhov, 2012)

which would require long start-up phases for a restart. By retaining the load ranges in the model, the changing rates and long-start up times for power plants could be therefore neglected at all.

The operation ranges, used in the model, were based by the REI data. The extracted values show totally different minimum load values than anticipated in real world power plant data. For instance, the minimum load for nuclear from the REI-data is 12%, which is significantly lower for the already mentioned minimum load of 50% of the rated capacity. The reason is simple, as this value originates in a combination of several power plants of one technology altogether. If a part of the nuclear power plant fleet is shut down, the value for this technology can be lower than that of 50%. The maximum value of 112% in nuclear, is set to 100% as this error derived probably due to additional (not officially restarted) power plants contributing energy to the grid. The finally implemented values in the model are shown in Table 5.4.

	max. load	min. load
Nuclear	100%	12%
Thermal	65%	12%
Hydropower	95%	10%
Geothermal	79%	29%
Bioenergy	67%	10%
H2 thermal	65%	0%

Table 5.4: Operation range of different technologies in percent of the rated capacity used in the model. "H2 thermal" refers to hydrogen-based thermal power plants.

In case of thermal energy, the assumption is, that Japan's government will most likely keep a mix of coal, CCGT[7] and gas turbines power plants for resource diversification and security reasons. As the latter ones can be shut down completely, it is possible that the overall value for this technology section (consisting of an entire power plant fleet) could be reduced to 12% instead of the 40-50% minimum load range for one coal power plant (Mayer, Kreifels, and Burger, 2013). It is expected that a part of the current thermal power plant fleet will also be modified to use hydrogen as fuel instead of the traditional fossil fuels like gas or oil. The substitution of fossil fuels in gas turbine or combined cycle gas turbine power plants are currently in research. For instance, the Japanese company JERA targets as a transitional solution a co-firing with ammonia by 20% in the 2030s and a full substitution in the 2040s (Patel, 2020). Although ammonia and hydrogen are not the same, it will be simplified in this thesis by addressing these plants further as hydrogen thermal power plants and are categorized as the $H2_{therm}$ technology. The use of hydrogen and ammonia in modified gas power plants is expected to have similar characteristics to conventional gas power plants. Therefore, the

[7]combined cycle gas turbine (CCGT)

same constraint as conventional thermal power plants derived from the data was used. The lower limit is set to zero as gas turbines allows to be shut down completely due to its fast reaction times. The efficiency of hydrogen in thermal power plants is set to 50%, derived from an assumption of a mix of the efficiency of CCGT 60% and gas with 32-38% (Gawlik, 2016).

5.5.2.2 The Priority of the Technologies

The order of technologies that are used first to meet the demand are in accordance with the dispatch rule and economic assumptions in 2050. The operation limit as well as the installed capacities of each technology serve as constraints for the model. Additionally, the priority order reflects differences in operational expenditures, efficiency, and ramping constraints of the assessed technologies. As shown in Table 5.5, there are two different priority orders depending on supply in relation to demand. In every hour of the year[8] the algorithm checks first, which case the algorithm has to follow. If supply is bigger than the current demand, it is lowered by case 1 and if supply is lower than the demand, it is elevated by case 2 as shown in Figure 5.8. It should be noted that, to enhance the clarity, the end of the loop (i=8760) was deliberately omitted from the figure. Additionally, the case where supply equals demand, causing the algorithm to proceed to the next loop iteration (i = i + 1) without changes in power output, is also not depicted.

No.	Case 1: supply > demand	Case 2: supply < demand
1	Battery load	Nuclear
2	Pumped storage (pump up)	Geothermal
3	Thermal	Hydropower
4	H2 thermal	Battery use
5	Biomass	Pump storage (generation)
6	Electrolysers	Biomass
7	Hydropower	H2 thermal
8	Geothermal	Fuel cells
9	Nuclear	Thermal

Table 5.5: Priority order of adjusting supply to demand in 2050 by technology and case. "H2 thermal" refers to hydrogen-based thermal power plants

If supply is higher than the demand, case 1 will be used. Strictly following the priority order number of case 1, the algorithm checks, if the chemical system batteries are fully loaded or not, and if required the batteries will be loaded (No.1). If the remaining

[8] one hour = one iteration i

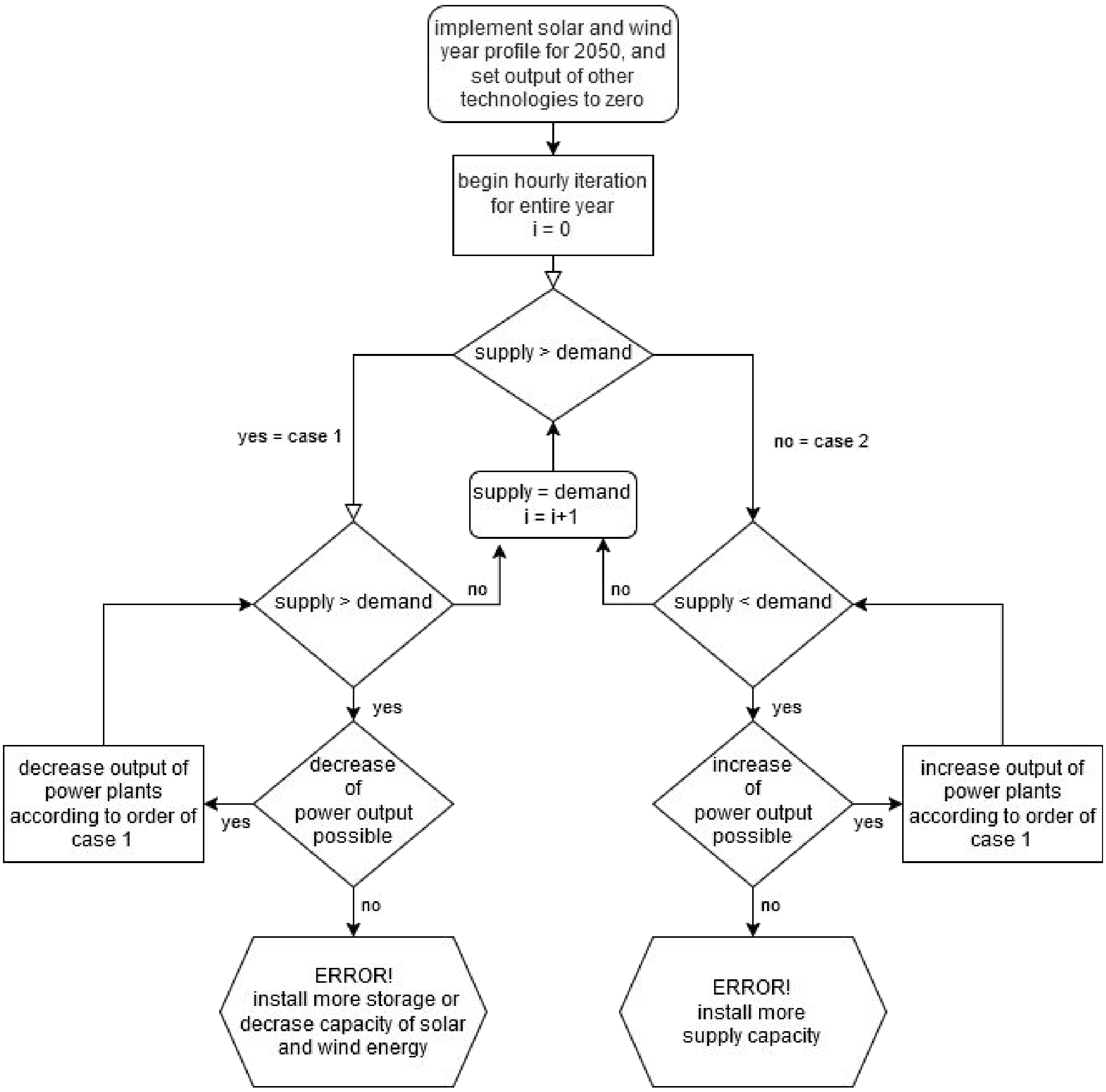

Figure 5.8: Conceptual flowchart of the algorithm

supply (supply subtracted now by the loading energy needed for the batteries) is still higher than the demand, it will then go to the next number of the order. The algorithm checks now the status of the pumped hydropower storage power plants and the need for refilling the storage (No.2). Right after these two types of system storage are filled, the next technology in line are already thermal power plants (No. 3). It is the first non-storage technology to be lowered in output in the order to support decarbonization and decrease CO2 emissions. However, to prevent the necessity of long restart times of power plants, after shutting them down completely, the output will only be lowered within the limitation of the normal operation mode and hence maintaining at least the minimum load for the technology, and subsequently jump to the next step/technology in the algorithm order. In this case, to number 4, which are the hydrogen thermal power plants. The order continues in this schemata. However, before finally lowering the output in base-load power plants (No.7-9) and to keep them in full operation as far as possible, hydrogen is produced by electrolysis beforehand (No. 6). By doing so, it is guaranteed, that domestic hydrogen uses solely excessive power from low-emission technologies. Only after using the full potentials of the installed capacity of the electrolysers base-load power plants would be needed to lower the output, as a last resort. If the supply is nevertheless too high, more storage would be needed to stabilize the electricity grid. The alternative of shutting power plants temporarily down or the curtailments of solar and wind power was not implemented as an option.

In the case of insufficient supply (case 2 of Table 5.5), the output of power plants will be increased and the systems batteries will be used. The order is not exactly the reversed order of the first case one but takes economic and ecological aspects into account. Beginning to increase the output of nuclear power plants as far as its maximum load, the supply will be adjusted until the demand is met. After full operation of the low carbon base-load power plants (No. 1-3) and before increasing the outputs of expensive power plants (No. 6-8) the system storage (No. 4-5) will be used first. Lastly, conventional thermal power plants (high carbon emitting) (No. 9) will be used as last option.

While the solar and wind standard profile are directly implemented to the supply, the starting condition for the other technologies is set to zero[9], allowing them to freely adjust themselves to the necessary amount, ignoring the start-up time at the beginning. The algorithm iterates then through every of the 8760 hours of one year. Therefore, after the first iteration (hour) the supply status of the previous hour is saved, which furthermore means that the condition (output status) of the power plants is saved, and used for the supply of the next hour, where the algorithm starts to check supply and demand again and adjusting the supply to the demand of the current hour.

5.5.2.3 Indicators

To evaluate the quality of the electricity generation mix in the model, three indicators were used in MATLAB. After iterating the entire year, the difference between demand and supply is measured in each hour of the year and recorded in the "*netval*" vector

[9] This means all power plants begin from a shut down state.

with 8760 individual values (see equation 5.2). The indicators include the sum, maximum and minimum of this vector, and are not absolutely necessary but provide a good insight to improve and stabilize the quality of the system.

$$netval(h) = demand(h) - supply(h) \tag{5.2}$$

1. Indicator 1 = sum of *netval*: The differences of demand and supply is summed up to one value and it must be negative for a secured supply. The exceeding supply can be stored in batteries or have to be curtailed. If the value is positive, supply is insufficient, inevitably leading to temporary shutdowns of selected demand segments. The value therefore shows how much energy is missing or exceeding in total. Greater absolute values mean more flexibility and stability, but also waste of energy, if not stored properly. From an economic perspective, values near *zero* are to be aimed. Values near *zero* on the contrary, show that supply is almost optimized to the demand in terms of installed capacity. However, values near zero do not necessarily imply optimized utilization. The other two indicators give an better insight in this matter.
2. Indicator 2 = maximum of *netval*:
   In the *netval* vector the biggest value among the 8760 values is searched and returned. If the value is positive, that means that there is a time in the year, when supply is insufficient. Since it returns the maximum it gives an insight on how much supply capacity is approximately still missing in the system.
3. Indicator 3 = minimum of *netval*:
   In the *netval* vector the smallest value among the 8760 values is searched and returned. It should be negative. That means that the supply exceeds the demand. The over supply can be saved into storage technologies and gives the insight of the needed storage capacity. A positive *netval* means that supply is insufficient throughout the year and never meets the demand and more supply capacity is needed at all costs.

If the system is optimized all the indicators should return *zero*. There is no insufficiency and no waste of energy. Exceeding energy is completely conserved in storage technologies. In this case, the supply would follow perfectly the demand profile.

Experimentally, the model has been tested with the predictions for the demand in 2050 and the initially anticipated need of installed capacities for the individual technologies with the 60% electricity generation share by renewable energies as described at the beginning of the chapter 5.5 and summarized in Table 5.9. It will be further adressed as scenario 0. The result of this test is given in Table 5.6, where the three indicators of the *netval* vector are stated. It shows, that in total, supply may satisfy the demand and surpass it by 4.5 *TWh* (sum value). However, at some point there is 70.6 *GWh* missing (max value), while on the contrary, supply surpasses at some point the demand by 95.1 *GWh* (min value).

Indicator 1	Indicator 2	Indicator 3
sum of *netval*	max of *netval*	min of *netval*
-4488 *GWh*	70.6 *GWh*	-95.1 *GWh*

Table 5.6: *netval* indicators for maximum demand in 2050 subtracted by supply with RE-share 60% target according to Japan's plan in *GWh* (see Table 5.3)

A more detailed evaluation of the test results can be made by the *netval* vector as shown in Figure 5.9. If supply and demand would be balanced at all time, the vector should be a flat horizontal line. However, it shows a high discrepancy between supply and demand throughout the year. The great share of volatile solar and wind energy in the power plant fleet composition shows strong fluctuations and destabilizes the system. While in the summer and winter there is a lack of supply, there is an massive over-supply in spring and autumn. For system stability reasons, this over-supply has to be cut off from the grid, otherwise this would lead to a collapse (blackout) of the electricity system. In the current model (for easy future reference it will be called Scenario 0), only the capacity targets of Table 5.3 have been implemented yet. Storage technologies are still not included in Scenario 0. Further simulation with the data showed additionally that the hydrogen electricity generation share was approximately nearly at 6%. The energy that had to be cut off is 22.5 *TWh*, which corresponds to approximately 1.7% of the total electricity demand in 2050. It reflects that merely guessing the needed capacity for 2050 (= Scenario 0) is insufficient.

A more detailed analysis is provided by the representation of the *netval* vector in the daily profile, disaggregated by month, as illustrated in Figure 5.10 for Scenario 0. Negative values indicate an excess of supply over demand, occurring predominantly during daytime, particularly in spring (March to June) and autumn (October to November). Conversely, supply shortages are observed primarily during the evening hours, peaking around 8 PM, and in winter months, additional deficits emerge in the morning hours.

5.5.2.4 The Necessity of Energy Storage

In general, by installing even more solar or wind capacity, the demand could be met at any given time, but this will also lead to several major problems. The utilization of the power plant would decrease and prevent optimal operation. Subsequently this would increase the costs significantly, which subsequently leads to an increased waste of energy. In addition, the space required for solar energy, for instance, would sooner or

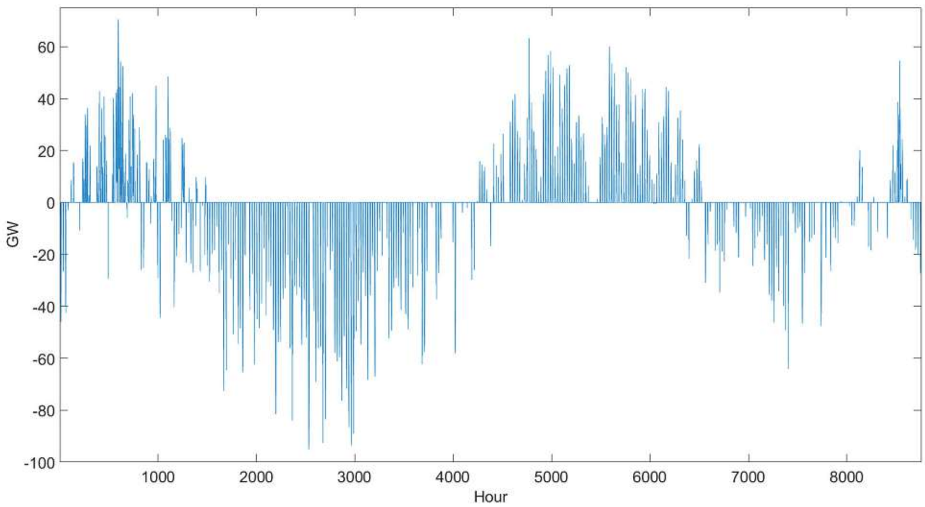

Figure 5.9: The *netval* vector represents the discrepancy between electricity demand and supply for each hour of the year. This Figure illustrates the maximum demand in 2050 minus the supply under a 60% renewable energy share target, as outlined to Japan's plan, reffered to as Scenario 0 in this thesis (see Table 5.3).

later reach its limits. Therefore, it is more rational to use storage technologies instead. The required space is reduced and the controllability of these technologies in particular enables resources to be used more efficiently. Furthermore, increasing storage capacity enables the redistribution of excess power generated during the day to the evening hours, as depicted in Figure 5.10. This effect will become more substantial with a higher share of solar energy in the system.

Presently, the only storage technology in Japan's electricity system is the pumped storage hydro power, and the current installed capacity with approximately 21.9 GW is considered already fully utilized at the nations potential limit. Additional necessary future storage capacity will hence be increased by two other technologies. Chemical batteries is one of them and will most certainly primarily be used as short-term storage to shift the daily supply-peaks to the evening demand-peaks. The second technology will be the long-term storage in form of hydrogen. Hydrogen can be produced by electrolysis using electric energy and it can be used in either fuel cells or as a substitution fuel like gas in modified thermal power plants. However, all these technologies are currently still associated with high costs. Especially, considering the conversions losses from electricity into hydrogen and then back again, the overall efficiency is with 20 kWh usable energy to the 56 kWh needed energy about 31.7% (see chapter 4.5.2).

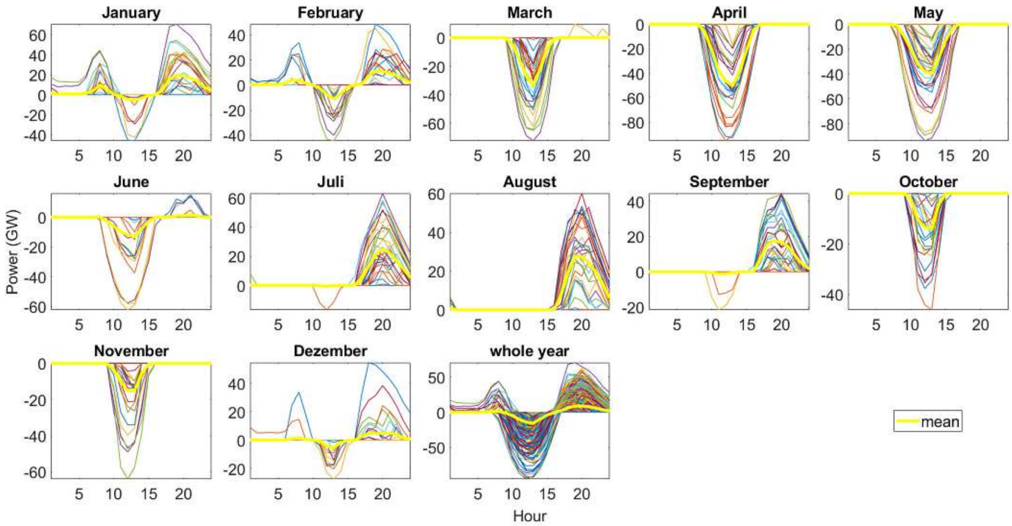

Figure 5.10: Daily profiles of *netval* by month in Scenario 0

This marks only the upper limit of the current technological advancement. If lower efficiencies for electrolysis and fuel cells with respective 60% and 50% are considered, then the overall efficiency decreases even to approximately 25.4%. In perspective to the pumped storage or batteries with around 80% and 90% efficiency (see below and chapter 4.5.2), respectively, this shows the inefficiency of hydrogen conversions from the energetic viewpoint. Unless the hydrogen fuel price is not considerably low, this will probably remain the most expensive technology among these three storage technologies.

While the parameters for modeling the batteries, the electrolyzers and the fuel cells are already given in Chapter 4.5.2, the implementation method of the existing pumped hydro power storage in the electricity system was not discussed yet. Different than to the other technologies in Table 5.3, this technology is a storage technology. That means it can only supply as long as there is energy saved up in the storage. The capacity of 21.9 GW describes only how "fast" it can contribute to the system. The duration of this supply is limited by the amount of energy that can be stored, which was extracted from the REI-data, by filtering the day with the most energy transfer for the pumping up and generation case. This was in 2019 on the 11th of September. On that day 127.2 GWh were pumped up, while 102.4 GWh were generated. It is assumed that on this day the storage was used to its fullest, until the storage is considered empty. The usable energy for supply marks therefore the storage size to 102.4 GWh, while due to losses the energy needed to fully load the storage is set to 127.2 GWh. The efficiency is hence around 80%. In reality the actual storage size could be even bigger than that, however due to the lack of actual data, the storage size was defined like this with the REI-data.

Compared to the usage of hydrogen in fuel cells, the production of it by electrolysis will play a much more important role. The capacity of the electrolyzers will determine the self-supply of hydrogen in Japan, and subsequently the dependency on foreign countries. If inexpensive hydrogen can fully be imported from abroad, electrolysers would not be necessary for the electricity system. Instead of storing the over-supply in the electricity system due to the contribution of renewable energies, the more economic option could be to "waste" the energy by simply cutting it off from the grid. However, the reliance on the supply of hydrogen supply solely from abroad is highly short-sighted and fortunately not planned by the government. There are purposes for hydrogen other than that of electricity supply. Hydrogen is globally seen as an important energy carrier in the future, which can be used in many fields and sectors. The most essential role could be in the transportation sector, when hydrogen will be used in fuel cell vehicles. In the following scenarios green energy will therefore not be wasted in any way but conserved by the implemented storage types in the model.

5.6 Scenarios

Although the government acknowledges that achieving complete decarbonization of the energy system may not be feasible, the scenarios presented aim to illustrate the requirements for fully phasing out fossil-fueled thermal power plants. The government projects that at least 30% of electricity generation in 2050 will still be derived from nuclear power and thermal power plants. A central element in this context is the expansion of nuclear power capacity to an estimated 40 GW, compensating for the projected capacity for thermal power plants by 2050. Consequently, conventional thermal power plants were excluded from the scenarios and replaced with thermal power plants utilizing hydrogen as fuel instead of fossil fuels. Furthermore, due to the limited potential of hydropower and pumped storage facilities, their installed capacities were fixed at 30 GW and 21.9 GW, respectively. Similarly, bioenergy expansion was set at 21.2 GW as indicated in Scenario 0. Battery capacity may vary across scenarios but will be constrained by a fixed maximum ratio of 1:3 to solar capacity. Based on these assumptions, multiple scenarios were simulated, each varying in power plant composition and emphasizing different energy technologies. These scenarios were designed to meet the minimum operational constraints, ensuring system stability and preventing computational errors, as illustrated in Figure 5.8. As a result, even the final remaining power source, nuclear power, can be reduced to a minimal operational level if required. Conversely, surplus electricity will be stored rather than curtailed. The resolution in installed capacity was set at 1 GW. While Scenarios 1 and 2 focus on the expansion of hydrogen technologies, Scenario 3 prioritizes the development of wind and solar energy. Scenarios 4 and 5 leverage the potential of geothermal energy, with the distinction that Scenario 5 incorporates a nuclear phase-out. Scenario 6 outlines the necessary expansion targets for solar, wind, and electrolyzers to fully meet the anticipated annual hydrogen supply of 20 million tonnes through domestic production. The scenarios were evaluated based on multiple criteria, as outlined below. The results of this assessment are presented at the end of the Chapter 5.7.6 in Table 5.10 as well as the individual fleet compositions in Table 5.9 at the end of the Chapter 5.6.

- Technical feasibility: Are the technologies fully matured, or do significant obstacles remain?
- Feasibility within the time-frame until 2050: How realistic is it to achieve the targets of each scenario by 2050?
- Grid stability & expansion: How stable is the grid? Is there a necessity for grid expansion?

- Economical aspect: What are the total costs for electricity generation? What is the influence of the costs for grid expansion?

- Energy security: Emphasis the independence from foreign countries by domestic hydrogen production and higher renewable energy share.[10] What is the remaining hydrogen not used for electricity generation, which can be utilized in other sectors such as heat and transport?

As previously mentioned, **Scenario 0** demonstrated that a high share of volatile solar and wind energy destabilizes the system. Additionally, the feasibility of deploying such a large amount of solar capacity within the given time-frame remains uncertain. Achieving 280 GW of installed capacity by 2050 would require a continuous annual expansion of nearly 7.5 GW. Considering the newly implemented Environmental Impact Assessment (EIA) process for solar energy, along with other regulatory barriers and societal resistance, meeting this target presents a significant challenge. In contrast, retrofitting conventional thermal power plants for hydrogen combustion is a more feasible and less complex alternative. Since this conversion primarily involves modifying existing infrastructure rather than fully reconstructing power plants, the transition could be implemented considerably faster.

5.6.1 Scenario 1 - Hydrogen Thermal (H2T)

Scenario 1 (H2T) prioritizes the deployment of hydrogen technology while significantly constraining the expansion of solar and wind energy. Wind energy deployment is limited to the officially stated minimum target of 30 GW[11]. Although no explicit governmental target exists for photovoltaic capacity, a complete cessation of its expansion is considered implausible. Therefore, its growth trajectory is significantly constrained, with an estimated annual increase of approximately 0.5 GW, resulting in a cumulative installed capacity of 100 GW by 2050. Additionally, a gradual expansion of fuel cells is incorporated, with an annual increase of 0.5 GW as well, ultimately reaching 13 GW by 2050. The remaining electricity demand is met through hydrogen-fueled thermal power plants.

To ensure overall supply sufficiency, the sum of *netval* (Indicator 1) serves as a benchmark, verifying that electricity generation aligns with demand. The findings indicate that the requisite capacity of hydrogen-based thermal power plants in Scenario 1 (H2T) amounts to 167 GW. Moreover, both additional indicators, minimum and maximum of

[10] As bioenergy stays constant in all scenarios, this influence can be neglected. Nuclear energy is seen as domestic energy by the government and the dependence on nuclear fuel is hence denied.

[11] The official target range for 2040 is set between 30 and 45 GW. However, in this hydrogen-centric scenario, the lower bound is adopted as the target for 2050.

netval (Indicators 2 & 3), are satisfied, signifying that neither additional battery storage nor electrolyzer deployment is necessary[12]. This outcome is attributed to the limited share of volatile energy sources and the existing pumped hydropower storage, which, in combination with the operational flexibility of the power plant fleet, ensures demand coverage at all times. However, in this composition the hydrogen consumption with 22.84 million tonnes exceeds the anticipated government hydrogen supply of 20 million tonnes per year. The hydrogen stock depletion occurs November 1. The integration of additional battery storage revealed that at the initial hydrogen thermal power capacity of 167 *GW*, Indicators 1 and 2 became insufficient due to efficiency losses associated with battery storage. Consequently, both the storage capacity and hydrogen thermal power generation needed to be increased until the indicators stabilized and hydrogen consumption fell below 20 million tonnes. Increasing the hydrogen thermal power capacity to 170 *GW* and battery storage to 33 *GW* ensured supply adequacy, reducing hydrogen consumption to 16.4 million tonnes.

The advantage of Scenario 1 (H2T) lies in the feasibility of retrofitting conventional thermal power plants. This approach primarily involves modifying existing infrastructure rather than constructing new facilities, which minimizes the duration of implementation and mitigates numerous bureaucratic barriers, although only a portion of existing plants may be suitable for such retrofitting.

5.6.2 Scenario 2 - Hydrogen Fuel Cell (H2FC)

Scenario 2 (H2FC), in contrast, represents a modification of Scenario 1 (H2T), which emphasizes the deployment of fuel cells. If an annual increase in installed fuel cell capacity of 3 *GW* could be achieved, the total capacity would reach 78 *GW* by 2050. This expansion would reduce the required capacity of hydrogen-fueled thermal power plants by 86 *GW*, lowering their target capacity to 81 *GW*. However, as in Scenario 1 (H2T), the hydrogen consumption exceeds the anticipated hydrogen supply without battery storage. Sufficiency was reached at 82 *GW* for hydrogen-based thermal power and 6 *GW* for battery storage. The consumption decreased from 21.18 to 19.78 million tonnes.

The advantages of fuel cells lie in their versatile applicability, higher efficiency, and reduced hydrogen consumption. In particular, smaller and decentralized systems can be integrated more effectively. For instance, public and residential buildings could implement localized fuel cell systems, enhancing energy security by mitigating risks associated with natural disasters such as typhoons or earthquakes. Additionally, the

[12] To prevent potential computational errors, a nominal battery and electrolyzer capacity of 1 *MW* was incorporated as a precautionary measure.

thermal energy generated during fuel cell operation can be utilized, further improving overall system efficiency.

5.6.3 Scenario 3 - Solar and Wind (SW)

Scenario 3 (SW) is focusing on solar and wind energy. The capacity targets are derived from Scenario 0, with the solar capacity set at 280 GW and the wind capacity rounded up from 77.65 GW to 80 GW. The residual electricity demand is addressed similarly to Scenario 1 (H2T), relying on hydrogen-fueled thermal power plants and a predefined fuel cell capacity of 13 GW. In this scenario, while the first indicator confirmed sufficiency at a hydrogen thermal power capacity of 41 GW, the second and third indicators indicated the necessity of integrating energy storage technologies. In the absence of storage systems, ensuring uninterrupted supply would require increasing hydrogen-based thermal power capacity to 138 GW, leading to an excess generation of 19.6 TWh, equivalent to 1.5% of total electricity generation. As in Scenario 1 (H2T), the incorporation of battery storage revealed that at the initial hydrogen thermal power capacity of 41 GW, the first indicator became insufficient due to efficiency losses associated with battery storage. Consequently, both the storage and hydrogen thermal power capacity needed to be increased. Given that the fuel cell capacity is fixed in this scenario and electrolyzers serve solely for surplus energy storage without directly contributing to supply, batteries remain the primary storage solution. Thus, battery capacity and hydrogen thermal power were incrementally increased in 1 GW steps until the algorithm verified supply adequacy at all times[13]. The battery storage capacity was constrained to a maximum of one-third of the installed solar capacity, reaching 93 GW. Depending on the installed battery capacity, the hydrogen thermal power requirement could be reduced from the initial 138 GW to 116 GW. Once supply adequacy was established, additional electrolyzer capacity was deployed to store remaining surplus energy. A selection of various capacity configurations[14] is summarized in Table 5.7.

H2 thermal	116	119	120	121	135	137	138
Battery	92	90	58	15	4	2	0
Electrolyzer	93	93	93	91	91	93	93

Table 5.7: Scenario 3 (SW): selection of various capacity configurations in GW. H2 thermal refers to hydrogen-based thermal power

A more detailed analysis revealed that the incremental increase in battery capacity and the corresponding reduction in required hydrogen thermal power capacity does not

[13] In other words, ensuring that the computational model does not fail under case 2 and return errors.

[14] The configuration with the maximum battery storage capacity and the minimum hydrogen-based thermal power capacity is presented in the summary table of all scenarios at the end of the chapter.

necessarily follow a linear relationship. This may be attributed to the limited storage capacity of batteries and the simplified nature of the algorithm. The model could lead to suboptimal battery utilization, rendering them unavailable at critical moments. Moreover, the installed battery capacity has only a minor impact on surplus electricity generation, which is why the required electrolyzer capacity remains nearly constant across all configurations, ranging between 91 and 93 GW. This substantial electrolyzer demand arises from the high share of variable renewable energy sources combined with significant seasonal fluctuations in electricity consumption. While batteries do not influence the required electrolyzer capacity, they drastically reduce the hydrogen fuel demand from an initial 10 million tonnes to 3.5 million tonnes. Simultaneously, the deprivation in total hydrogen production via electrolysis, from 1.9 million tonnes to 1.1 million tonnes, is comparatively less significant. However, this also implies that the economic viability of electrolyzers diminishes as their utilization declines (see Table 5.8).

Battery capacity (GW)	92	90	58	15	4	2	0
Hydrogen production (Mt)	1.05	1.07	1.36	1.74	1.87	1.92	1.95
Hydrogen consumption (Mt)	3.52	3.55	4.74	7.29	8.95	9.49	10.01

Table 5.8: Scenario 3 (SW): hydrogen production and consumption in million tonnes (Mt) by battery capacity in GW

Table 5.8 defines the minimum requirements for the algorithm, where the entire power plant fleet, including nuclear power, operates at its lowest feasible output. Maximizing the hydrogen production via low-carbon technologies could be achieved by operating low-carbon base-load power plants at full capacity. However, this would necessitate an increase in installed electrolyzer capacity by an additional 62 GW across all configurations, reaching a total of 153 – 155 GW. Consequently, hydrogen production could rise to 1.2 – 2.1 million tonnes, representing an increase of 7.5 – 12.7%.

The unpredictable behavior of batteries highlights that they cannot be reliably accounted for when determining the necessary supply capacities and must be considered with caution. Stored battery energy could be depleted at the most inopportune times. Additionally, their impact on reducing required electrolyzer capacity is marginal. A more reliable energy storage alternative could be fuel cells, where storage capacity is solely dependent on hydrogen fuel reserves, which can be planned for long-term availability.

5.6.4 Scenario 4 - Nuclear and Geothermal (NucGeo)

Scenario 4 (NucGeo) maximizes the full technically feasible potential of geothermal energy, which is estimated at 23 *GW*. Concurrently, it maintains nuclear power generation at 40 *GW*, consistent with Scenarios 1 – 3 (H2T, H2FC, SW). Additionally, a marginally increased expansion rate for solar and wind power is assumed. For wind energy, the higher bound of the official target for 2040 is adopted as the target for 2050. The annual deployment rate for solar power exceeds 1 *GW*, reaching a total of 120 *GW* by 2050. Fuel cell capacity remains at 13 *GW*, consistent with the other scenarios. Based on these assumptions, the capacity of hydrogen-based thermal power plants is incrementally expanded to ensure supply adequacy throughout the year, reaching a required capacity of 136 *GW*. At this stage, no additional energy storage technologies are required. Further analysis indicates that either an increase in solar or wind capacity to 126 *GW* or 72 *GW*, respectively, would still maintain system stability while slightly reducing the required hydrogen-based thermal power capacity to respective 134 *GW* or 129 *GW* without the need for additional storage. Although installing the maximum battery capacity of 40 *GW*[15] does not decrease the total required capacity for hydrogen-based thermal power, it diminishes hydrogen consumption by more than 34%, reducing it from 12.23 to 8.04 million tonnes. This scenario highlights the resilience of the energy system, allowing the continued expansion of variable renewable energy sources without immediate large-scale storage solutions, especially for wind energy. The challenge of large-scale energy storage can thereby be postponed, enabling more strategic support for specific technological developments.

5.6.5 Scenario 5 - Geothermal (Geo)

Scenario 5 (Geo) explores the full potential of geothermal energy, as in Scenario 4 (NucGeo), but without nuclear power, representing a nuclear phase-out scenario. When comparing this scenario with Scenarios 1 (H2T) and 2 (H2FC), it becomes evident that the overall share of base-load power plants declines significantly. Moreover, hydrogen technology alone is insufficient to compensate for this reduction, as hydrogen consumption rapidly exceeds the anticipated supply. Even under the more moderate expansion rates for solar and wind assumed in Scenario 4 (NucGeo), supply adequacy required 197 *GW* of hydrogen-based thermal power and a fixed 13 *GW* of fuel cells, resulting in a hydrogen consumption of 33.5 million tonnes.

The nuclear phase-out necessitates significantly higher deployment rates for solar and wind. Consequently, the same challenging expansion targets as in Scenario 3 (SW)

[15] The configuration without battery storage is used in the summary table of all scenarios at the end of the chapter.

were adopted. Battery capacity was set at the predefined maximum limit of 93 *GW* to directly mitigate hydrogen consumption. Similarly, the fuel cell deployment rate from Scenario 2 (H2FC) was maintained, fixing its capacity at 78 *GW*. Based on these assumptions, hydrogen-based thermal power capacity was increased to 84 *GW* to ensure year-round supply adequacy. Under these conditions, hydrogen consumption is reduced to 11.7 million tonnes, with sufficient electrolyzer capacity of 89 *GW*.

This scenario demonstrates that a nuclear phase-out is a feasible option, though it necessitates challenging expansion targets across all other technologies. While the required deployment of solar, wind, batteries, and electrolyzers could be reduced, this would come at the expense of significantly higher hydrogen consumption, thereby limiting its availability for other sectors such as transportation.

5.6.6 Scenario 6 - Domestic Hydrogen (DomH2)

Scenario 6 (DomH2) aims to assess the required installed capacity of solar and wind to fully meet the targeted government hydrogen supply of 20 million tonnes through domestic production. The assumptions include an optimized scenario, such as the complete utilization of geothermal potential at 23 *GW* and nuclear power at 40 *GW*, as in previous scenarios. For fuel cells and hydrogen-based thermal power, the respective expansion targets of 78 *GW* and 82 *GW*, as outlined in Scenario 2 (H2FC), are adopted. The solar capacity, along with a fixed battery capacity in a 3:1 ratio, is incrementally increased until it reaches a limit of 500 *GW*[16], while wind capacity is simultaneously expanded without restriction until supply adequacy is achieved. The required capacities for solar, battery and wind power are 500 *GW*, 167 *GW*, and 444 *GW*, respectively. Electrolyzers are required at a capacity of 422 *GW*. Further analysis reveals that, in this configuration, the reliance on hydrogen-based thermal power and fuel cells is entirely eliminated, as the contributions from the other sources are sufficient to meet the electricity demand. Both technologies are assigned a lower priority in the model and, as a result, are not utilized. Consequently, all produced hydrogen can be allocated for alternative uses such as heating or transportation.

This scenario highlights the improbability of achieving such expansion targets within the short time frame until 2050. It also indicates that Japan will continue to rely significantly on foreign sources in the future, reflecting a mere shift in the type of source rather than a reduction in dependency. Should fossil fuels continue to be utilized, hydrogen would emerge as an additional resource rather than a substitution, thereby enhancing diversification and contributing to the strengthening of energy security.

[16] The nation's theoretical potential limit for solar photovoltaic capacity is 522 *GW*. For further details, see Chapter 3.4.

Even though the complete decarbonization of the energy system is not the primary focus of this thesis, the integration of conventional thermal power plants with carbon capture technology could facilitate higher domestic hydrogen production, which could ultimately be used in sectors such as heating or transportation. However, incorporating this aspect would require substantial modifications to the model, which is specifically designed to mitigate the use of conventional thermal power plants. This approach could even hinder the decarbonization process by diverting focus away from the expansion of renewable energy sources. Additionally, due to conversion losses, utilizing thermal power plants directly for electricity generation is more efficient than prioritizing them for hydrogen production. Furthermore, the expansion of solar and wind power would necessitate sufficient electrolyzer capacity, as the presence of additional thermal power plants would accelerate the occurrence of oversupply. In the absence of sufficient electrolyzer capacity, this surplus energy would have to be curtailed more frequently, further impeding the rapid deployment of solar and wind energy. On the contrary, producing hydrogen domestically within this framework would allow the government to regulate and ensure genuinely carbon-neutral hydrogen production. If hydrogen were to be imported, regulatory oversight would be limited, leaving the government dependent on assurances from foreign companies or governments.

Scenario	1 (H2T)	2 (H2FC)	3 (SW)	4 (NucGeo)	5 (Geo)	6 (DomH2)
Nuclear	40	40	40	40	0	40
Thermal	0	0	0	0	0	0
Hydropower	30	30	30	30	30	30
Geothermal	4.16	4.16	4.16	23	23	23
Bioenergy	21.2	21.2	21.2	21.2	21.2	21.2
Solar	100	100	280	120	280	500
Wind	30	30	80	45	80	444
H2 thermal	170	82	116	136	84	82
Fuel cell	13	78	13	13	78	78
Electrolyzer	0	0	93	0	89	422
Pu. storage	21.9	21.9	21.9	21.9	21.9	21.9
Battery	33	6	92	0	93	167

Table 5.9: Installed capacity targets by scenario and technology in 2050 in *GW*

5.7 Assessment of the Scenarios

Table 5.9 summarizes the installed capacity targets for the different scenarios. While each scenario has a distinct focus, all - except for Scenario 6 (DomH2) - are designed to feasibly achieve their respective targets. As outlined at the beginning of the chapter, the scenarios will be evaluated based on multiple criteria. Given the complexity of conducting a precise and fully objective assessment, a ranking system is used to enable structured comparison despite uncertainties. This ranking system assigns a placement to each scenario based on its relative performance in each category. Hence, lower number means better rating. If multiple scenarios perform equally within a specific category, they receive the same placement. The results are presented in Table 5.10 at the end of the criteria evaluation section.

5.7.1 Technical Feasibility

One of the most challenging categories is the comparison of technical feasibility. All scenarios include hydrogen-based thermal power plants. According to IRENA, the peak installed capacity for natural gas occurred in 2018, reaching 84 *GW* (IRENA, 2024b). Gas turbines are the most suitable category of thermal power plants that can be retrofitted to utilize hydrogen as fuel. IRENA data also revealed that the rapid expansion of several gigawatts per year is possible, suggesting that hydrogen-based thermal power plants may face the least obstacles. The primary limiting factor is expected to be the availability of hydrogen supply, which is anticipated to grow steadily over time.

Two other technologies also need to be considered. Some scenarios explore the full potential of geothermal energy with current technology. However, it remains uncertain whether this potential can be fully employed. While there is still untapped potential, it is currently associated with significant technical challenges. A similar situation applies to wind energy. Expanding wind capacity to 80 *GW* would require a significant portion to be developed in offshore areas. While there is still potential in the field of fixed-bottom offshore wind energy, which is technically feasible, it remains challenging. When directly comparing wind energy and geothermal energy, wind energy tends to be more technically feasible. The location for wind energy is easier to assess than for geothermal energy, which requires test drilling. Although these drillings are based on comprehensive analysis, they carry a degree of uncertainty.

Other technologies are well-established and play a less significant role in this category.

5.7.2 Feasibility within the Given Time-frame until 2050

The feasibility of achieving the targets by 2050 is assessed by considering both the time-frame and the magnitude of the capacity goals. Based on these factors, Scenario

2 (H2FC) emerges as the most feasible, followed by Scenario 1 (H2T). However, due to the higher hydrogen-based thermal power capacity target, only a substantial fraction can be accommodated through retrofitted power plants, while the remainder would require the construction of new plants. Additionally, the storage requirements for Scenario 1 (H2T) are higher compared to Scenario 2 (H2FC). Scenarios 3 (SW), 5 (Geo), and 6 (DomH2) demand significantly higher storage capacities and electrolyzers, making Scenario 4 (NucGeo) comparatively less complex to implement. It also has only moderate targets. In contrast, Scenarios 3 (SW), 5 (Geo), and 6 (DomH2), along with the solar and wind energy targets, present considerable challenges, although the rapid expansion of solar capacity in the past decade has demonstrated that such high growth rates are achievable. The primary challenge, however, resides in wind energy. Scenarios 3 (SW) and 5 (Geo) are considered equally achievable, while Scenario 6 (DomH2), with its exceptionally high targets, appears unfeasible within the given time-frame.

The revival of nuclear energy is not anticipated to encounter substantial obstacles. Currently, 31 *GW* of nuclear capacity is available, pending necessary safety inspections before recommissioning. Furthermore, additional plants are already under development. As a result, this technology plays a relatively minor role in the present assessment.

5.7.3 Grid Stability & Expansion

Grid stability primarily concerns the system's capability to rapidly adapt to substantial fluctuations in energy supply or demand. Two fundamental aspects must be considered in this context. However, the simplified model used in this thesis addresses only one of these dimensions. Specifically, the model assumes an unrestricted energy transfer, neglecting constraints or bottlenecks. In reality, energy transmission is inherently limited by the capacity of power lines and inter-connectors. This limitation has been entirely omitted, despite the fact, that this issue is a critical challenge in Japan, as the presence of two distinct grid frequencies and segmentation into ten sub-regions introduces additional complexity. Variable renewable energy sources, such as solar and wind, have a substantial destabilizing effect on the grid, as their output cannot be actively regulated—except through curtailment—and remains dependent upon fluctuating availability. To mitigate energy wastage due to curtailment, the integration of energy storage technologies becomes essential. The necessity for storage solutions increases not only in the temporal but also in the spatial dimension, making unhindered energy transfer to demand centers essential. This spatial factor is particularly crucial for wind energy.

When evaluating the different scenarios, the model predominantly favors base-load technologies, thereby resulting in a noticeable positive impact on grid stability when these technologies have a significant share in the energy mix. Hence, within the framework of this model, base-load technologies have a crucial role in aligning energy supply with demand. Furthermore, the reduced necessity for storage capacity fundamentally enhances grid stability. Based on these criteria, Scenario 4 (NucGeo) emerges as the most stable configuration by a considerable margin. It does not necessitate storage technologies and could even accommodate additional solar (+6 GW) or wind (+27 GW) capacity without necessitating the deployment of energy storage systems at all. Scenario 2 (H2FC), followed by Scenario 1 (H2T), requires only minimal storage capacity and can thus be ranked immediately after Scenario 4 (NucGeo) in terms of stability.

Scenarios 3 (SW) and 5 (Geo) show comparable storage requirements, since both scenarios share identical preconditions regarding solar and wind expansion targets. However, while Scenario 5 (Geo) necessitates a higher capacity of battery storage, Scenario 3 (SW) requires a greater capacity of electrolyzers. This distinction arises due to the higher share of base-load power plants — particularly nuclear power — in Scenario 3 (SW), which have a limited ability to reduce their output below a certain degree. Although power plant maintenance has been implicitly accounted for by the operational range constraints, further optimization in this regard could potentially reduce the required storage capacity beyond that of Scenario 5 (Geo). Consequently, Scenario 3 (SW) is preferred over Scenario 5 (Geo). Finally, Scenario 6 (DomH2) exhibits the highest storage capacity requirements, making it the least favorable in terms of grid stability.

5.7.4 Economic Viability

In Chapter 4, the levelized cost of electricity has been analyzed under two distinct scenarios, STEPS and NZE, as conducted by the IEA. By integrating these findings with the electricity generation data in GWh per technology and scenario, the total electricity generation costs can be calculated by using Equation 5.3. The results of the total generation costs is illustrated in Figure 5.11. However, these costs represent only a fraction of the overall expenditures. In addition to generation costs, system integration costs (grid expansion) have a significant role.

$$C_{scenario} = \sum LCOE_{tech,scenario} \cdot E_{tech} \tag{5.3}$$

where:

$C_{scenario}$ = total electricity generation costs by *scenario* in USD
$LCOE_{tech}$ = levelized costs of electricity by *technology* and *scenario* in USD/kWh
E_{tech} = produced total energy by *technology* in kWh

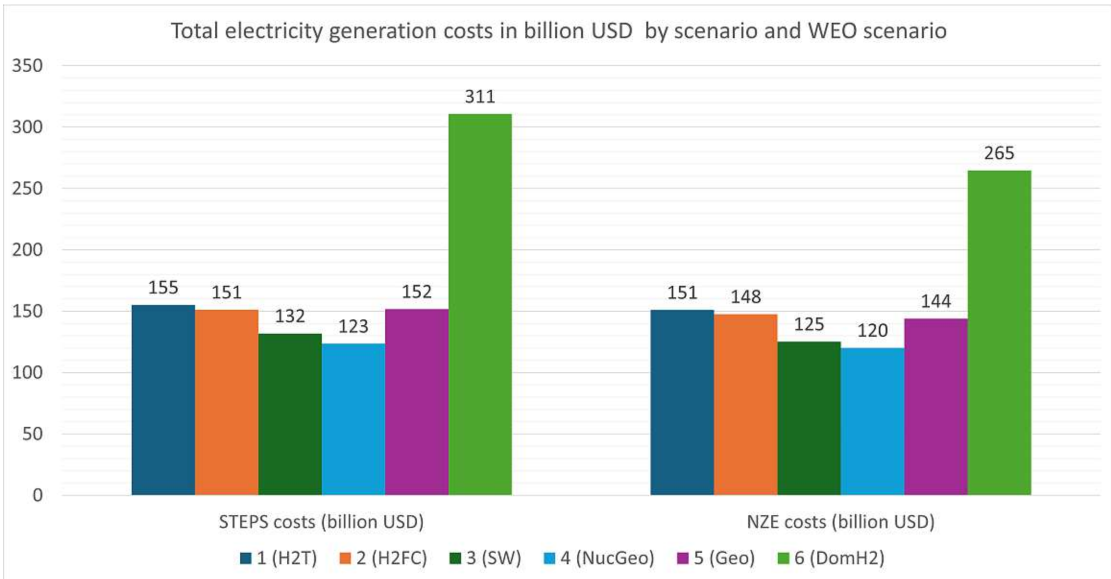

Figure 5.11: Total electricity generation costs in billion USD by scenario and WEO scenario

As mentioned in the previous section, the spatial dimension is especially critical for wind energy. Wind farms must be constructed in locations with economically viable wind conditions. Since these optimal sites are not necessarily near to demand centers, substantial costs are caused by grid connectivity. Consequently, grid expansion represents another major cost factor. However, in this thesis, these costs are not quantitatively assessed, and the scenarios are ranked based on their potential cost implications. It is assumed that higher target levels for solar and wind correspond to increased costs. Based on these assumptions, Scenarios 1 (H2T) and 2 (H2FC) incur the lowest costs, followed by Scenario 4 (NucGeo). Scenarios 3 (SW) and 5 (Geo) are considered equivalent in terms of cost implications, whereas Scenario 6 (DomH2) results in the highest costs. The two primary cost categories — electricity generation costs and indirect system integration costs — have been ranked separately within distinct subcategories.

5.7.5 Energy Security

Domestic hydrogen production will have a significant impact on national energy security, as it can reduce reliance on foreign sources (see Figure 5.12). In this context, Scenario 6 (DomH2) distinguishes itself as the sole case in which the projected hydrogen supply of 20 million tonnes is exclusively sourced from domestic production, positioning it as the predominant model. 86% of the electrical energy demand is covered by the significant share of solar and wind energy, while the remaining 14% is fulfilled by base-load technologies. This enables the entire produced hydrogen to be allocated to other energy sectors (see Figure 5.13).

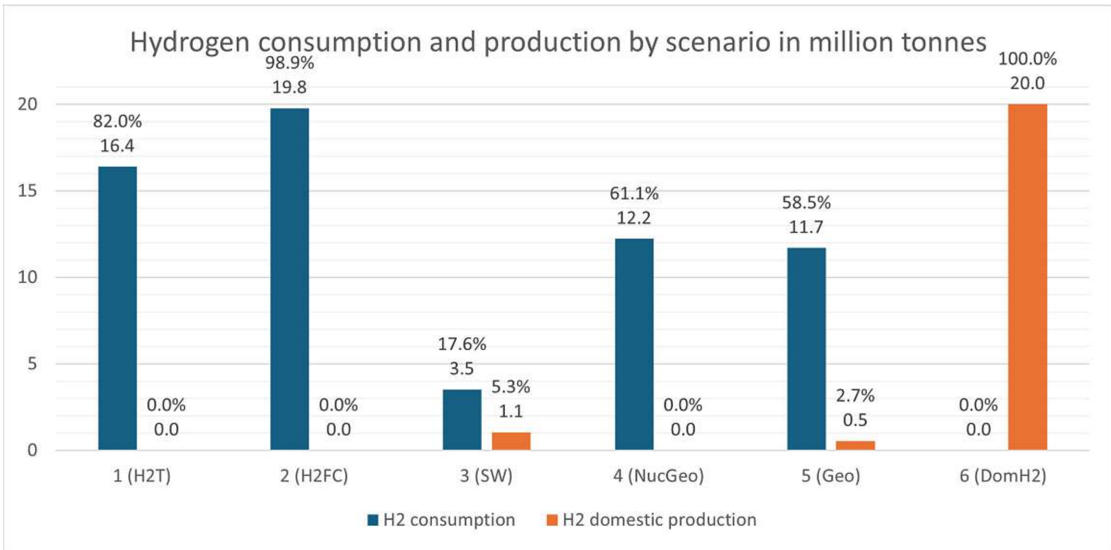

Figure 5.12: Hydrogen consumption and domestic production in million tonnes by scenario

When comparing the other scenarios, as shown in Figure 5.12, it becomes apparent that even with higher expansion rates for solar and wind energy, the share of domestic hydrogen production does not exceed 6%. Scenario 3 (SW), with 5.3%, followed by Scenario 5 (Geo) at 2.7%, illustrate that the dependency on foreign hydrogen supply remains significantly high in the examined scenarios. Although the differences in domestic production across these scenarios are minimal, the higher share of solar and wind in the electricity supply substantially reduces hydrogen consumption. As a result, Scenario 5 (Geo) leaves approximately 42% of the anticipated 20 million tonnes available for other energy sectors, whereas in Scenario 3 (SW), this share increases to around 82%. In the remaining scenarios, Japan relies entirely on foreign imports for hydrogen, with differences observed only in consumption levels. Scenario 4 (NucGeo), with the highest base-load power plant capacity, demonstrates the lowest consumption. Scenarios 1 (H2T) and 2 (H2FC) exhibit the highest hydrogen consumption, with Scenario 2 (H2FC) nearly consuming the entire anticipated supply. Although the model accounts for a higher fuel cell efficiency in Scenario 2 (H2FC), the overall con-

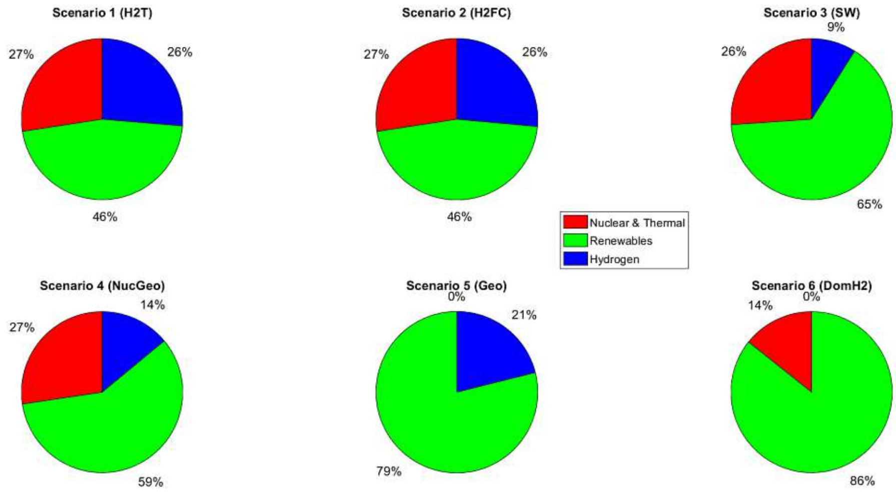

Figure 5.13: Electricity generation share by scenario

sumption remains higher than in Scenario 1 (H2T). This is primarily due to the lower installed battery capacity. As discussed in the scenario descriptions, battery capacity plays a significant role in reducing hydrogen consumption.

5.7.6 Results

As already mentioned at the beginning of Chapter 5.7 a ranking system is employed to enable a structured comparison. It assigned a placement to each scenario based on its relative performance in each category. If multiple scenarios performed equally within a specific category, they received the same placement. Table 5.10 presents the relative placement of each scenario across different evaluation criteria, where lower numbers indicate better ratings. Due to the varying significance of each criteria, no aggregated final ranking is provided. If weighting were applied, different conclusions could be drawn, but that would require additional analysis, which is beyond the scope of this thesis. Hence, this table merely allows for a comparative assessment, where the relative advantages and disadvantages of each scenario can be identified.

The results indicate that no single scenario excels across all criteria. Each scenario involves trade-offs. While certain scenarios have strengths in specific aspects, these come at the expense of other factors.

For instance, Scenario 4 (NucGeo) is the most stable and economically viable scenario, but has weaknesses in terms of energy security and technical feasibility.

Scenario	H2T 1	H2FC 2	SW 3	NucGeo 4	Geo 5	DomH2 6
Technical feasibility	2	1	3	4	5	6
Feasibility within the time-frame	2	1	4	3	5	6
Grid stability and expansion	3	2	4	1	5	6
Economic viability: generation costs	5	4	2	1	3	6
Economic viability: system integration costs	1	1	4	3	4	6
Energy security	5	6	2	4	3	1

Table 5.10: Scenario ranking by placement and different criteria

Scenario 1 (H2T) and 2 (H2FC) perform well regarding technical and temporal feasibility, as well as grid stability and low system integration costs due to the reduced need for grid expansion. However, this comes at the expense of energy security and generation costs, as the high demand for expensive hydrogen is exclusively imported.

Apart from the highly unlikely Scenario 6 (DomH2), which primarily serves to illustrate the renewable energy capacity required for full energy autonomy, Scenario 5 (Geo), representing a nuclear phase-out, ranks lowest in most categories. Although it represents a feasible scenario, its performance underscores the plausibility of maintaining nuclear energy in Japan's near future.

Scenario 3 (SW) demonstrates relatively strong economic performance in terms of generation costs and energy security. However, its implementation is highly challenging due to technical constraints and the limited time-frame. Grid stability and system integration costs also remain important concerns.

In summary, these trade-offs highlight the necessity of carefully balancing priorities when determining the most appropriate energy transition strategy for Japan.

6 Conclusions & Limitations

In this chapter the main conclusions for the three parts of this thesis will be briefly presented again. Tables and figures referenced in this chapter can be found in the previous chapters, where also more detailed information to the individual parts and conclusions is provided.

6.1 Conclusions on Renewable Energy Potentials in Japan

Japan has sufficient theoretical renewable energy potential to fully decarbonize both its electricity system and overall energy demand. Hydropower, as the country's first renewable resource, is already well established, leaving only marginal potential for further expansion. In contrast, Japan possesses the third-largest geothermal potential globally, which remains largely underutilized. This limited development is primarily due to societal conflicts of interest (especially the use of geothermal resources for thermal bathing), high investment risks, and the government's strong focus on nuclear energy.

Despite rapid expansion in recent decades, Japan still has substantial untapped potential in solar energy. However, the greatest renewable energy potential lies in wind power, which, similar to geothermal energy, has been predominantly neglected until recent years. It was only after Japan's intensified decarbonization efforts in 2020 that wind energy gained significance. Wind power is also the only renewable energy technology for which the government has set explicit capacity targets (30 *GW* by 2030 and 45 *GW* by 2040). However, crucial technical challenges remain in fully exploiting this potential, as the majority of Japan's wind energy resources are located offshore, particularly in deep waters, where conventional fixed-bottom wind turbines are not feasible. In these areas, floating offshore wind technology is required, yet this technology is still in the early stages of development. Currently, government-support for new wind farms locations are in designated offshore zones in shallow coastal waters, where fixed-bottom turbines are utilized.

For an overview of the theoretical and realistic renewable energy potentials in Japan, refer to Table 3.6 in Chapter 3.7.2.

6.2 Conclusions on Electricity Costs in 2050 in Japan

In the second part of this thesis, a cost projection for the levelized cost of electricity and storage (LCOE, LCOS) of various technologies was conducted until 2050, considering two different WEO scenarios (STEPS and NZE). Renewable energy technologies were analyzed separately from nuclear, hydrogen-based, and storage technologies. The results for the year 2050 are aggregated and summarized in Figure 6.1.

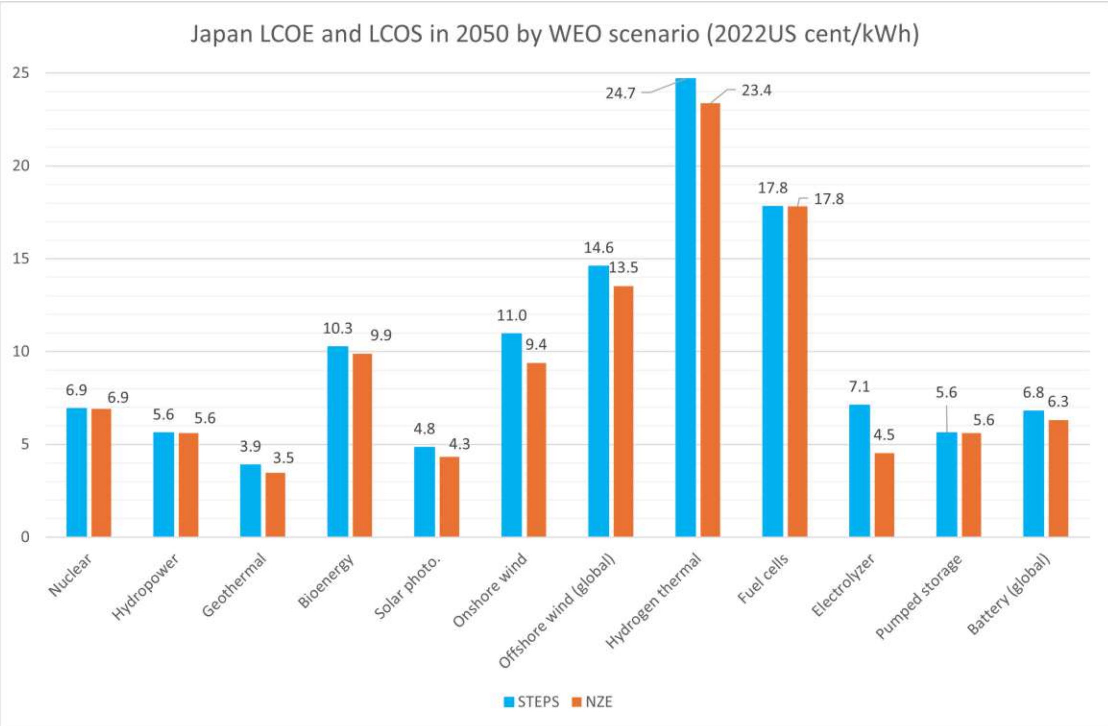

Figure 6.1: Levelized costs of electricity and storage in Japan in 2050 by WEO scenario

Among renewable energy sources, offshore wind remains the most expensive technology. Since offshore wind power in Japan, aside from a few pilot projects for research purposes, has not been existent until recently, cost estimates are based on global standards due to the lack of national data. Consequently, actual costs could be even higher. Another important factor is the absence of cost estimates for the emerging floating offshore wind technology, which is expected to play a crucial role due to its greater potential.

In contrast, geothermal energy proves to be the most cost-effective renewable energy source.

Overall, hydrogen-based technologies have the highest projected costs, primarily due to the significant expensive hydrogen fuel.

The combination of numerous variables, limited data availability, necessary assumptions, and the extended projection period of 25 years results in considerable uncertainty regarding the realism and scientific robustness of this cost projection. Nevertheless, Figure 6.1 provides an indication of how electricity costs in Japan could evolve until 2050.

6.3 Conclusions, Model Limitations and Key Findings on the Assessed Scenarios

This section summarizes key conclusions from the scenario assessment, outlines model limitations, and proposes improvements. Based on the findings, a structured decarbonization pathway is suggested.

6.3.1 Conclusions on Assessed Scenarios

At the end of Chapter 5, the developed scenarios were assessed using a comparative placement ranking system, where lower values indicate better performance. Scenarios performing equally within a specific category received the same placement. The results are presented in Table 5.10 (see previous Chapter 5.7.6). While it would be possible to create an overall ranking by combining all results into one score, this approach has been deliberately omitted. Different criteria have different levels of importance depending on national priorities. Such an assessment would require assigning appropriate weights to the different criteria. Since this would necessitate a more complex analysis, it was not included in this thesis. The results of the assessment therefore allows merely for a comparative assessment rather than a definitive ranking.

In summary, no single scenario outperforms all others across all criteria. Each scenario has its distinct advantages and disadvantages.

Relying on hydrogen-technology for instance, reduces the need for expensive grid expansion. However it also diminishes energy security as expensive hydrogen is entirely imported. Additionally, this reliance leads to higher electricity generation costs. In this regard, utilizing geothermal energy (while also maintining nuclear energy) proves to be the most cost-effective and stable solution. Nevertheless, this approach provides lower energy security than Scenario 4 (SW), which emphasizes on the expansion of solar and wind energy. This trade-off arises from the still significant dependence on hydrogen imports.

Prioritizing solar and wind appears beneficial in terms of energy security and electricity generation costs. However, it necessitates extensive grid expansion, since optimal solar and wind locations are spatially separated with demand centers, thereby increasing system integration costs. Additionally, without sufficient storage capacity, grid stability deteriorates tremendously, potentially forcing grid operators to curtail excess solar and wind generation under certain conditions.

6.3.2 Key Findings in the Assessed Scenarios

Four fundamental insights can be derived from the scenario outcomes. Firstly, battery storage has only a small impact on required supply capacities, but it significantly affects the overall hydrogen consumption. Secondly, a transition away from fossil energy carriers appears technically feasible. However, the elimination of multiple energy sources would reduce energy security. This issue is directly linked to the third key finding: domestic hydrogen production plays only a marginal role in overall supply. The substantial reliance on hydrogen imports does not contribute positively to energy security. Nevertheless, this assumes that the expected annual supply of 20 million tons of hydrogen will actually be fully needed. If hydrogen demand were lower, the proportion of self-sufficiency would consequently increase. However, more detailed analysis is required to accurately estimate future hydrogen demand.

The fourth and final finding concerns nuclear energy. In principle, a nuclear phase-out is feasible. However, the comparatively lower performance of this scenario relative to the alternatives reinforces the government's plan to maintain nuclear power in the near future until 2050.

6.3.3 Model Limitations and Suggestions for Improvements

The developed model operates with a highly simplified framework, which may result in inaccuracies or deviations from realistic outcomes. However, it still provides an approximate estimation. To conduct more precise analyses, enhancements to the model are necessary. Below is a selection of suggested improvements to address these limitations.

- Implement grid constraints, including energy transfer limitations.
- Enhance spatial and detailed data on power plants to improve modeling accuracy:

  - Utilize real operational data with physical constraints.
  - Categorize technologies into subtypes, such as onshore and offshore wind (fixed-bottom and floating) to reflect differences in capacity factors and behavior.
  - Enable seasonal operation strategies to optimize energy use and reduce reliance on electrolyzers.
- Implement maintenance requirements, allowing modifications and repairs to be scheduled during periods of lower demand.
- Include buffer capacity to account for unexpected incidents and enhance system resilience.
- Integrate economic data to adjust the supply endogenously in the model.
- Improve capacity optimization, addressing model limitations caused by the fixed priority order and behavioral changes:
  - Replace rigid priority order with an adaptive management system.
  - Implement smart battery charging and usage strategies, including seasonal management profiles.
  - Utilize battery technologies with longer discharge durations.
- Strengthen integration between solar/wind energy and storage technologies, such as batteries or electrolyzers, to explore methods for stabilizing supply.

6.4 Suggested Approach for a Decarbonization Pathway

Advancing all technological pathways simultaneously is beneficial to accelerate decarbonization as much as possible. However, based on the analyzed scenarios, a more efficient decarbonization strategy can be derived, allowing for more targeted investments and policy support in specific areas. This approach assumes that Japan will rebuild its nuclear fleet as planned by the government and abolish the use of fossil fuels.

Under the given conditions, priority should be assigned to the rapid conversion of existing fossil-fueled gas-fired thermal power plants to hydrogen-based operation while ensuring a stable hydrogen supply. This approach could represent one of the fastest pathways for mitigating greenhouse gas emissions. Although this represents a cost increase from an economic viewpoint, gas-fired power plants are not exclusively deployed for base load generation. In particular, their limited operation within the balancing energy sector may allow to compensate the high hydrogen fuel costs through enhanced compensation for reserved capacity. By this approach a gradual expansion of the technology could be achieved, particularly as hydrogen costs decrease over time.

Targeted subsidies could be employed to reduce the financial burden. Various policy instruments and regulatory frameworks are available to support this transition.

While gas-fired thermal power plants can be retrofitted with comparatively low technical effort to operate on hydrogen, this is generally not feasible for other conventional fossil-fueled thermal power plants that utilize solid or liquid fuels, such as coal or oil. For these systems, it would be advisable to utilize the almost neglected geothermal energy. However, as the potential of geothermal energy is insufficient to fully replace the significant share of electricity generated by such plants, a complementary large-scale deployment of fuel cell should be promoted as soon as it becomes technically and economically viable. In particular, decentralized application of fuel cells, where both electricity and heat are utilized simultaneously, can improve overall efficiency and increase economic feasibility. Due to their higher efficiency compared to hydrogen-fueled thermal power plants, fuel cells are expected to progressively replace them in the long term.

As demonstrated in the scenarios, hydrogen supply will rely almost entirely on imports. It is crucial to source hydrogen from low-carbon production methods to prevent shifting emissions abroad, which would ultimately worsen the global CO_2 balance rather than contributing to genuine decarbonization.

The next step would be the expansion of electrolyzer capacity, particularly to the extent that seasonal demand fluctuations in spring and autumn no longer impact the operation of low-carbon base-load power plants. Ideally, demand variations should be balanced by hydrogen production through electrolysis rather than by reducing power plant output. This approach would maximize the efficiency and economic viability of these power plants while simultaneously eliminating curtailments and promoting domestic hydrogen production.

Expanding solar and wind energy remains crucial, however, it must be accompanied by appropriate storage solutions. As an initial measure, existing renewable energy installations without storage should be retrofitted. This would enhance grid stability while simultaneously creating additional flexibility for integrating new installations, which may initially operate without storage due to supply chain delays or other constraints. If a choice had to be made between the two, solar energy would be the preferable option. However, its deployment should always be coupled with battery storage, as the ability of batteries to reduce hydrogen consumption far exceeds the domestic hydrogen production potential of electrolyzers. Conversely, electrolyzers should be prioritized for converting wind energy into storable hydrogen. As indicated by the scenario analysis, seasonal demand fluctuations cannot be effectively managed with battery storage alone. Instead, they must be addressed by storing hydrogen produced via electrolysis, which is particularly relevant for wind energy integration.

As several other challenges remain in Japan's electricity grid — such as unifying the national grid frequency to either 50 or 60 *Hz* and transitioning to higher voltage levels to reduce losses — these aspects fall outside the scope of this discussion. However, it is essential that grid expansion, particularly improvements in transmission capacity between regions, should progress alongside the expansion of solar and, especially, wind energy. This would optimize the direct use of generated electricity, minimizing the reliance on energy storage and reducing associated conversion losses.

Although the proposed strategy does not represent a universally optimal solution, it serves as an informative guideline for policymakers seeking a structured approach to Japan's energy transition.

Appendix

Feedstock in EJ / year	2050	2100
Biocrops	1.34	1.61
Surplus wood	0.7	0.75
Agricultural residues	0.68	0.47
Municipal waste	0.47	0.33
Black liquor	0.26	0.31
Livestock residues	0.156	0.12
Forestry residues	0.13	0.13

Table A1: Bioenergy potential assumption in Japan in 2050 and 2100 (Wu et al., 2020)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Solar photo.	5124	4392	3343	2935	2652	2016	1833	1586	1355	1120	983	917	876
Offshore w.	5217	5975	5288	5589	5884	5902	4647	5249	5134	4114	3483	3052	3461
Onshore w.	2186	2153	2213	2048	1994	1840	1829	1825	1741	1653	1496	1418	1274
CSP	10082	11879	9180	7202	6182	8259	8681	8217	5894	7383	5079	9728	4274
Hydrop.	1407	1387	1482	1676	1546	1689	2002	2054	1610	1912	2075	2299	2881
Geothermal	2904	-	5895	4243	4005	3922	4119	4295	4624	4450	4045	4300	3478
Bioenergy	2904	2791	1952	3397	3345	2908	2440	3251	1900	2481	2819	2518	2162

Table A2: Global weighted average total installed costs in 2010-2022 (2022 USD / kW) (IRENA, 2023b)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Solar photo.	40	72	102	137	176	224	296	391	487	589	722	866	1055
Offshore w.	3	4	5	7	8	12	14	19	24	28	34	54	63
Onshore w.	178	216	262	293	341	405	453	496	540	594	699	771	836
CSP	1	2	3	4	5	5	5	5	6	6	7	6	7
Hydrop.	1026	1057	1090	1137	1176	1210	1246	1271	1294	1312	1334	1362	1393
Geothermal	10	10	11	11	11	12	12	13	13	14	14	14	15
Bioenergy	66	73	78	85	91	98	106	112	119	126	136	143	151

Table A3: Global installed renewable electricity capacity in GW (Source:IRENA, 2024b)

capacity factor	2022
Solar photovoltaic	16.90%
Offshore wind	41.65%
Onshore wind	36.80%
Hydropower	46.00%
Geothermal	85.00%
Bioenergy	72.00%

Table A4: Global weighted average capacity factors in 2022 (Source: IRENA, 2023b)

Global Total Installed Costs by Scenario (2022 USD / *kW*)							
		STEPS			NZE		
	2022	2030	2040	2050	2030	2040	2050
Solar photo.	876	368	239	200	314	186	157
Offshore w.	3461	2595	2153	1948	2316	1875	1694
Onshore w.	1274	914	787	767	827	621	576
CSP	4274	2197	987	610	948	263	174
Hydrop.	2881	1848	1848	1848	1848	1848	1848
Geothermal	3478	2973	2545	2341	2522	2067	1921
Bioenergy	2162	2027	1910	1823	1930	1710	1629

Table A5: Global total installed costs by scenario (2022 USD / *kW*)

O&M costs	USD / *kW*	USD / *kWh*
Solar photo.	3.4 - 31	-
Offshore wind[1]	-	16 - 25% of LCOE or 0.017-0.030
Onshore wind	30 - 81	up to 30% of LCOE
CSP	-	0.02 - 0.04
Hydropower	1 - 4% of investment costs or 20-60	-
Geothermal	110	-
Bioenergy	2-6% of total installed costs	or 0.005

Table A6: Global Operation and maintenance cost range 2010 - 2022 by IRENA (IRENA, 2023b)

technology	economic life (years)	WACC (real) for OECD and China	
		2010-2019	2020
Solar PV	25	7.50%	5.00%
Wind	25		
CSP	25		
Hydropower	30		
Bioenergy	20		
Geothermal	25		

Table A7: Assumption for the weighted average cost of capital for OECD and China by technology between 2010-2020 by IRENA (IRENA, 2023b)

(2022 US cent / kWh)	IRENA*	STEPS			NZE		
	2022	2030	2040	2050	2030	2040	2050
Solar photo.	4.9	2.7	2.1	1.9	2.5	1.8	1.7
Offshore wind	8.1	8.0	7.2	6.8	7.5	6.6	6.3
Onshore wind	3.3	3.3	3.0	2.9	3.1	2.6	2.5
CSP	11.8	6.4	4.1	3.4	4.0	2.7	2.5
Hydropower	6.1	4.8	4.8	4.8	4.8	4.8	4.8
Geothermal	5.6	4.3	3.9	3.7	3.9	3.4	3.3
Bioenergy	6.1	6.9	6.8	6.7	6.8	6.5	6.4

Table A8: Global weighted average levelized costs of electricity for renewable energy by World Energy Outlook scenario (2022 US cent / kWh) *(Source:IRENA, 2023b)

Solar photo.	1895
Offshore wind	6640
Onshore wind	3520
Hydropower	2975
Geothermal	2800
Bioenergy	3138

Table A9: Total investment costs in Japan in 2022 by IEA (2022 USD / kW)(derived from Source: IEA, 2023b)

(2022 US cent/ kWh)	IRENA*	STEPS			NZE		
	2022	2030	2040	2050	2030	2040	2050
Solar photo.	9.6	6.9	5.3	4.8	6.2	4.7	4.3
Offshore wind	22.1	17.3	15.5	14.6	16.1	14.3	13.5
Onshore wind	15.0	12.2	11.1	11.0	11.4	9.8	9.4
Hydropower	n.s	5.6	5.6	5.6	5.6	5.6	5.6
Geothermal	n.s	4.5	4.1	3.9	4.1	3.6	3.5
Bioenergy	n.s	10.7	10.4	10.3	10.5	10.0	9.9

Table A10: Levelized costs of electricity for renewable energy in Japan in 2050 by WEO scenario (2022 US cent / kWh)

	STEPS		**NZE**	
2022 USD / kW	**Capital costs**	**O&M costs**	**Capital costs**	**O&M costs**
Japan	**2050**	**2050**	**2050**	**2050**
Nuclear	4 000	225	4 000	225
Fuel cell (distr. e - gen)	2 500	50	2 500	50
Coal + CCS	4 900	145	4 150	125
Oxyfuel + CCS	5 550	165	5 200	155
IGCC + CCS	5 550	195	4 650	165
CCGT + CCS	2 600	65	2 150	55

Table A11: Capital cost and operation and maintenance cost assumption for non renewable technologies by the world energy outlook 2023 scenarios STEPS and NZE (IEA, 2023b)

Capital costs (global)		STEPS	APS	NZE
2022 USD	2022	2050	2050	2050
Hydrogen electrolysers (USD / kW)	1070-1640	530 - 740	360-510	330-470
Utility-scale stat. battery (USD / kWh)	315	140	135	130

Table A12: Capital cost and operation and maintenance cost assumption for non renewable technologies by the global energy and climate model scenarios STEPS and NZE (IEA, 2023a)

LCOE in Japan (2022 US cent / kWh)	STEPS	NZE
Nuclear	6.9	6.9
Hydrogen Thermal	24.7	23.4
Fuel Cells	17.8	17.8
Electrolysis	7.1	4.5
Pumped Storage (same as Hydro)	5.6	5.6
Battery (global)	6.8	6.3

Table A13: Levelized costs of electricity for various technologies by world energy outlook 2023 scenario for 2050 in Japan

assumed variables		
	lifetime (n)	**capacity factor**
Nuclear	60	90%
Fuel cell	15	57%
Coal + CCS	30	50%
Oxyfuel + CCS	30	50%
IGCC + CCS	30	50%
CCGT + CCS	30	50%
Battery	10	12.50%
Electrolyzer	15	15%

Table A14: Further assumption to calculate the levelized costs of electricity other various energy technologies for 2050; (based on sources: IEA, 2023b; IEA, 2023a; Lorenczik and Keppler, 2020)

GW		STEPS			NZE		
	2022	2030	2040	2050	2030	2040	2050
Solar PV	1 145	4 699	9 500	12 639	6 101	14 303	18 753
Wind	902	2 064	3 242	3 874	2 742	5 797	7 616
CSP	7	16	46	85	48	251	427
Hydro	1 392	1 571	1 801	2 028	1 765	2 313	2 612
Geothermal	15	27	47	63	48	99	129
Bioenergy	168	232	311	393	296	541	688

Table A15: Assumed global installed capacity in *GW* for renewable technologies by Word Energy Outlook 2023 scenario (IEA, 2023b)

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