Renewable pathways to climate-neutral Japan

Reaching zero emissions by 2050 in the Japanese energy system

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Key messages of the study

1. **Net zero emissions can be achieved in Japan at reasonable costs based on renewables deployment and electrification.** An interim target of at least 40% renewables in power generation is required in 2030 to transition towards a 100% objective in 2050. Electrification of heat, transport and industry, as well as various flexibility options (such as grid reinforcement, storage and demand-side flexibility) will facilitate the integration of renewables, while bringing down emissions to net zero in 2050.
2. **A three-step roadmap is needed to achieve climate neutrality by 2050.** The first step consists of a 45% reduction in greenhouse gas emissions by 2030 (relative to 2010). Second, emissions must decline by at least 90% by 2045 (relative to 2010). Finally, green synthetic fuels eliminate residual emissions, mostly from high-temperature heat generation in industry.
3. **Hydrogen will be used sparingly, even if it is imported, as direct electrification is more efficient and less expensive.** Direct electrification should therefore be prioritized wherever possible in transportation, space heating and low and mid-temperature heat in industry. Domestic production of green hydrogen will also put considerable pressure on the power system.
4. **Nuclear power is not necessary to achieve the long-term decarbonization target at lower cost.** Renewables will outcompete nuclear new build and lifetime extension projects already by 2025, leading to a gradual phase-out of nuclear power plants at the end of their technical lifetime if not stopped earlier.
5. **Japan has to kick-start enhanced climate action as soon as possible and increase its interim sectoral targets to reach 45% lower GHG emissions and at least 40% renewables in power generation by 2030.** The upcoming discussions on the 6th Strategic Energy Plan and concrete regulatory measures, such as an effective carbon pricing mechanism, will be crucial to determine how Japan goes about achieving those interim 2030 targets and climate neutrality by 2050.

Table of Contents

Executive summary

Five years after the adoption of the Paris agreement,[1] 2020 saw many countries committing to a climate neutrality target by 2050, including Japan, the European Union, the UK, South Korea and lately the USA. China has also committed to making its economy climate-neutral by 2060. The Japanese pledge is a fantastic opportunity to fundamentally transform the country's energy system over the next thirty years and overcome its current dependence on fossil fuels.[2] With this new pledge, Japan significantly accelerates its climate commitment, increasing its previous national targets from an 80% greenhouse gas (GHG) emissions reduction[3] to a completely decarbonised society by 2050. This transformation is needed quickly, and it will be crucial to determine a pathway towards net zero emissions that sets ambitious yet achievable interim goals for 2030 and beyond. The development of the 6th Strategic Energy Plan offers an important opportunity to review those interim targets.

2020 was a turbulent year. The COVID-19 pandemic has very much challenged the international community. In Japan, public spending was increased by 70% to $1.6 trillion (¥175 trillion) in 2020 to respond to the crisis. The increase amounts to about 13% of annual GDP, showing strong efforts can be made when necessary. In order to accelerate the transformation of the Japanese energy system towards climate neutrality, public and private investments, including those made as stimulus spending, should target climate mitigation measures through a large-scale investment program within the framework of a Japanese Green Growth strategy.

Several technology options exist to decarbonize the energy system. At the international level, several countries such as Germany are adopting renewables-based decarbonization strategies. In Japan, however, the experts and policy discussions are still largely open regarding the long-term role of renewables, nuclear and CCS technologies, as well as the use of synthetic fuels such as hydrogen.

This study, conducted by Renewable Energy Institute (REI) and Agora Energiewende with the support of LUT University, describes pathways that Japan can take to achieve climate neutrality by 2050 based on renewables in the most cost-effective way. The study covers all energy-related greenhouse gas emissions (GHG), as well as some emissions from industry processes based on fossil fuels (such as steel making). In total 88% of all current GHG emissions are covered, including energy conversion (38%),

[1] It set "to limit global warming to well below 2, preferably to 1.5 degrees Celsius, compared to pre-industrial levels".
[2] Japan currently imports 88% of its primary energy mostly in the form of fossil fuels. Data from Ministry of Economy, Trade and Industry – Agency for Natural Resources and Energy, "Energy White paper 2020".
[3] No base year provided

transport (17%), buildings (10%) and industry (23%).[4,5] The evolution of final energy demand was estimated based on three framing assumptions: population decline (-20% between 2017 and 2050 according to governmental projections), current levels of industrial output will be maintained, and moderate energy efficiency improvements. The sectors were modelled in 3 categories of energy use: power, heat and transport, and all their GHG emissions are accounted for. The cost-optimized modelling was conducted in five-year steps with an hourly resolution to ensure the supply-demand balance at each hour between the nine interconnected grid regions in Japan.[6] Stakeholder meetings were organized with the main stakeholders in the debate in Japan in order to validate the assumptions and discuss the preliminary results.

I. Japanese emissions today slightly below 1990 levels

Energy policies to reduce energy consumption – whether because of supply security, air pollution, resource scarcity, or geopolitical dependence – have been around for a very long time in Japan. Climate considerations are a more recent development.[7] In the Kyoto protocol, Japan committed to a 6% reduction of GHG emissions by 2012 relative to 1990 levels.

As can be seen in Figure 1, GHG emissions increased in the 1990s, peaking in 2013 at 1 408 Mt CO_2eq. Emissions rose mainly due to a gradual increase in energy consumption in the commercial and industrial sectors; furthermore, fossil fuel temporarily replaced nuclear power after the Fukushima accident in 2011. In particular, nuclear power dropped from 25% before the accident to 6% afterwards, with the gap being closed mostly by gas, but also with some additional coal and oil power generation. Japan decided not to participate in the second commitment period (2013 to 2020) of the Kyoto protocol.

By 2018, overall emissions had decreased by 12% compared to 2013, which is about 2.5% below 1990 levels. Most of the emissions reductions since 1990 were achieved in the industry sector (-21% before allocation of the emissions from the energy conversion sector) through energy efficiency of processes and the replacement of a large share of its oil consumption (by gas and electricity). However, this decrease was partly compensated by an increase in emissions in the energy conversion sector linked to rising industrial demand. In electricity generation, the deployment of renewables has partially compensated for the increase of CO_2 emissions due to the reduction of nuclear power. Since 2010, new policies have been introduced to support the installation of renewable energy, with particular emphasis on the rapid expansion of PV (62 GW installed at the end of 2019). As a result, renewables represented 9.3% of primary energy supply in 2019 and 18% of power generation, explaining most of the emissions reduction since 2013. Emissions in the building sector decreased by 10% between 1990 and 2018, while no changes were made in the transport sector.

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[4] Non-energy-related emissions from industrial processes, agriculture and waste were not taken into account in this study. In the industrial sector, non-energetic emissions such as limestone from cement or the chemical industry were not included, while process emissions for steelmaking (reduction of iron ore) were accounted as energy-related emissions (even though oxidoreduction is not strictly speaking a combustion reaction). In total, the non-energy-related emissions in Japan amounted to about 153 $MtCO_2$eq in 2018 (12% of total GHG emissions). Important efforts will be required to reduce those emissions, but since they are more difficult to abate, some remaining emissions are expected by 2050. Those remaining emissions will need to be offset by carbon sinks to reach climate neutrality in the overall Japanese economy, notably through CCS in the industry, direct air capture (DAC) as well as land use, land-use change and forestry (LULUCF). The emissions from international bunkers (aviation and maritime transport) are excluded from the national emissions as in the United Nations Framework Convention on Climate Change (UNFCCC) approach and are excluded from this study.

[5] Figures according to Greenhouse Gas Inventory Office of Japan (GIO), National Greenhouse Gas Inventory of Japan 2020

[6] The isolated EPCO region of Okinawa was not considered in this study.

[7] After the UN Framework Convention on Climate Change was adopted at the environmental summit in Rio de Janeiro in 1992, binding emissions reduction targets were set by the 1997 Kyoto Protocol.

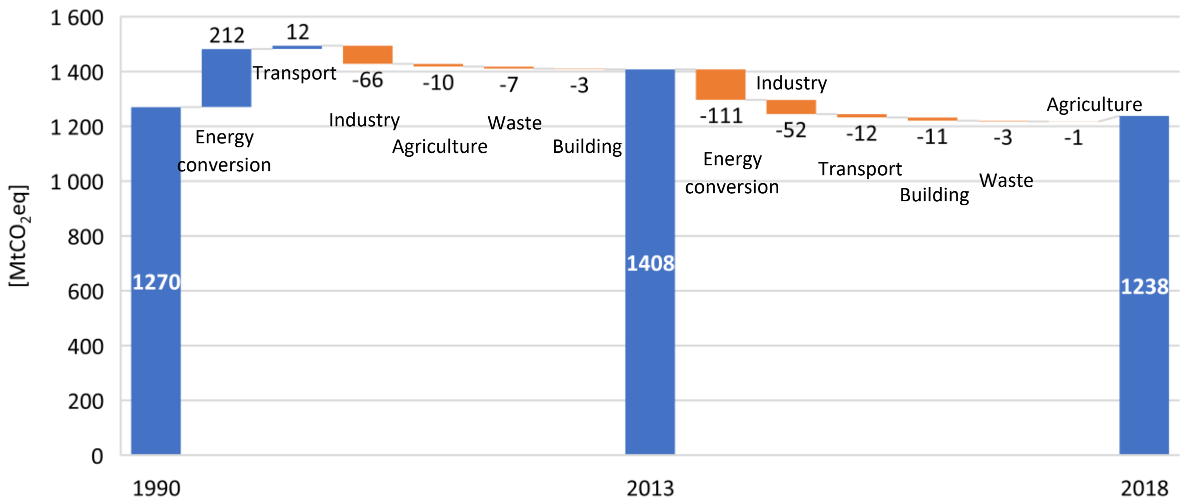


Figure 1: Reduction of GHG emissions since 1990 (in Mt CO_2eq, before allocation of emissions from the energy conversion sector into demand sectors). Source: own presentation from National Greenhouse Gas Inventory of Japan, Greenhouse Gas Inventory Office of Japan (GIO)

The Strategic Energy Plan has set Japanese mid- to long-term energy targets since 2003. With the current plan (5th and latest plan from 2018), Japan aims at reducing its GHG emissions by 26% by 2030 relative to 2013. This nationally determined contribution (NDC) has been criticized as not being sufficiently ambitious and not compatible with the Paris agreement. And indeed, some sectoral targets are partly already achieved, in particular in the industry sector, which already reached its indicative reduction target (-6.5% CO_2 emissions relative to 2013) in 2016, 14 years ahead of time.

In order to reach climate neutrality by 2050, the interim targets set in the Strategic Energy Plan will need to be increased in order to put Japan on a path towards climate neutrality as quickly as possible. The elaboration of the 6th Strategic Energy Plan provides a major opportunity for enhancing interim GHG reduction targets and clarifying the question of the long-term energy mix in Japan. In order to contribute to this debate, this study proposes a robust and cost-effective techno-economic pathway based on renewables for climate neutrality by 2050.

II. Three steps towards climate neutrality in Japan by 2050 (in the energy-related sectors)

As can be seen in Figure 2, the decarbonization pathway proposed in this study follows a three-stage process:

1. By 2030: GHG emissions decrease by 45% (relative to 2010)
2. By 2045: GHG emissions decrease by 90% (relative to 2010)
3. By 2050: zero GHG through an increased use of green synthetic fuels in the last step of the transition to eliminate residual emissions, mostly linked to high temperature heat generation in industry

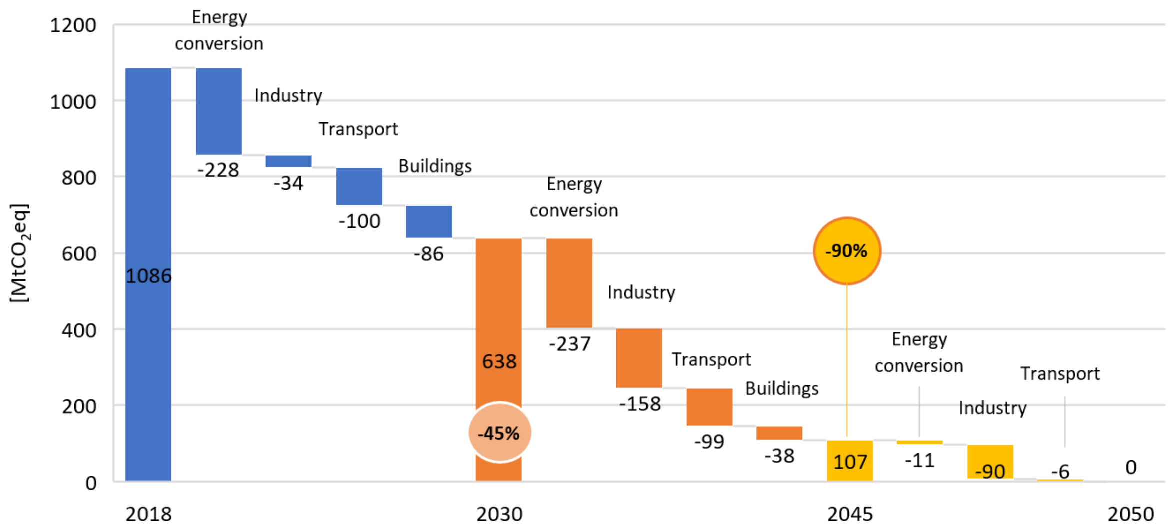


Figure 2: Pathway towards climate neutrality by 2050 in the energy consuming sectors (in Mt CO_2eq).

Step 1: Reduce GHG emissions by 45% by 2030 relative to 2010

In order to make climate neutrality possible by 2050, GHG emissions must be reduced drastically starting today. Actions taken in the 2020s will decide whether climate neutrality can be achieved by mid-century. To be in line with the 1.5-degree scenario for Japan, emissions should be reduced by 45% by 2030 relative to 2010. This goal represents a very significant strengthening of the current reduction target of -26%.

The energy conversion sector has the greatest GHG reduction potential (-230 Mt CO_2eq by 2030 below the latest available emissions data from 2018), followed by the transport (-100 Mt CO_2eq by 2030) and building sectors (-86 Mt CO_2eq by 2030). Industry could contribute with a reduction of 34 Mt CO_2eq.

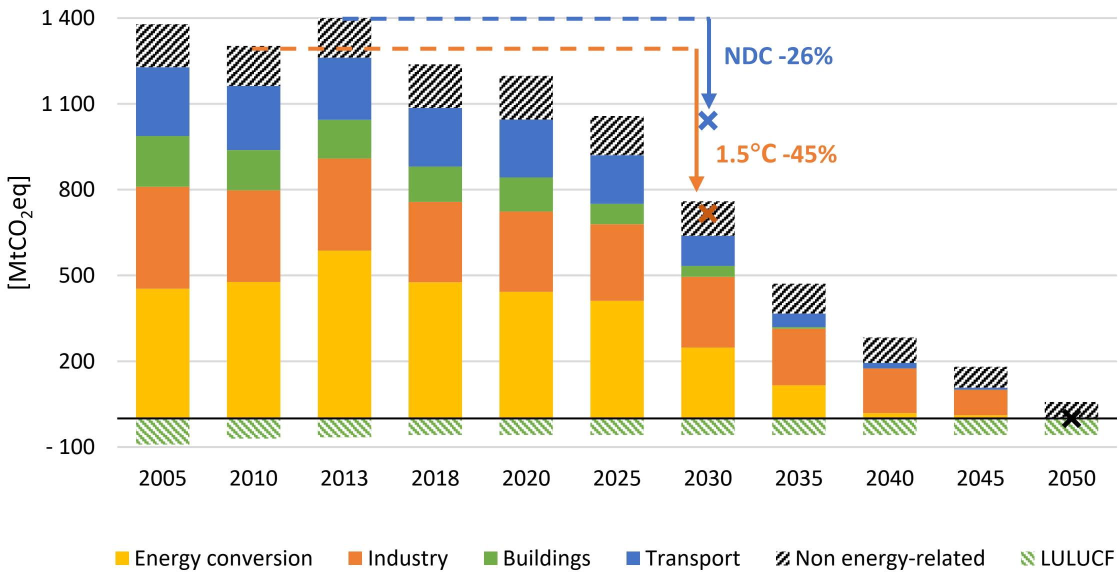


Figure 3: Base Policy Scenario with imports – evolution of energy-related GHG emissions per sector and current climate targets (in Mt CO_2eq).

The cornerstone of the strategy lies in the transformation of the **energy conversion sector**. An accelerated coal phase-out in power generation by 2030 and the increased expansion of renewables in power generation (to at least 40% of power generation) will provide the lion's share of emissions reductions. To assess the feasibility of replacing all nuclear generation by renewables at this time horizon, this scenario contains no additional nuclear restart and a nuclear phase-out by 2030. Growing electrification in all sectors will slightly increase electricity consumption between 2020 and 2030 (+5%, corresponding to 48 additional TWh). To cover the demand, the installed capacity of PV more than doubles (144 GW in 2030), while wind capacity sees a six-fold increase (25 GW in 2030) so that renewable power generation reaches about 400 TWh (against 185 TWh in 2019). The required annual net newly installed capacity is then 8.4 GW of PV, 1.5 GW of onshore wind, and 0.7 GW of offshore wind between 2021 and 2030. In comparison, 8.5 GW of PV and 0.2 GW of onshore wind were installed yearly on average between 2014 and 2019.

Prosumers[8] play an important role even in this first stage of the transition. Due to relatively high retail electricity prices, prosumer PV is highly competitive in densely populated areas such as Tokyo, leading to a quick capacity growth of decentralized PV in the 2020s. From 23 GW of installed PV for prosumers in 2020, it more than doubles in 10 years, reaching 70 GW by 2030. This amount represents half of the total installed PV capacity and helps reduce the area footprint of the RE-based energy system.

Reducing emissions in the **industrial sector** will require further energy efficiency improvements and the electrification of low and medium temperature heat first. For high temperature heat applications that are difficult to electrify directly, substituting fossil fuels with green hydrogen will start to be relevant in 2030. New processes in the basic materials industry, in particular steel, will further contribute to emission reductions. The steel industry in particular could be a pioneer in this regard by replacing old blast furnaces with direct reduction systems fueled mainly by hydrogen and smaller proportions of natural gas in the interim. Sustainable solutions for carbon as a reduction agent exist by mid-century, such as the use of biomethane, synthetic methane and biochar. Although these technologies will mostly be deployed after 2030, it will be important when making reinvestment decisions in the 2020s to avoid stranded assets that would be climate-incompatible in the long run. In addition, investment decisions in recycling routes (in order to increase the use of secondary raw materials) and the import routes for hydrogen should be tackled well before 2030 so that these solutions can exploit their full potential after 2030.

In the **building sector**, people mostly keep their heating behaviors in the scenario. Efficient heat pumps quickly expand as they become cheaper than conventional devices, so that electricity covers the demand. Old buildings are replaced by new builds complying with ambitious energy efficiency standards or receive energy efficient retrofits. The energy efficiency gains compensate for a possible rebound effect,[9] so that final heat consumption in 2030 is 7% below current levels (same as today in terms of consumption per capita level).

In the **transport sector**, there is a slight change in current trends. Mobility habits do not transform, but people use slightly more public transport, cycle and walk more. Direct electrification is expected to develop with the adoption of battery-electric and plug-in hybrid vehicles in all road transport segments (light, medium and heavy-duty vehicles including buses), as well as rail transport assumed to be fully electrified. In 2030, 12.5 million electric vehicles will be on the roads (against about 1 million

[8] In this study, prosumers are residential, commercial and industrial entities installing PV systems on their rooftop, with or without lithium-ion batteries. See section 2.1 for more details.

[9] The "rebound effect" is the well-known phenomenon that improving energy efficiency may save less energy than expected due to an increase in consumption, such as by increasing the average heating temperature.

today). This trend in electrification and efficiency will keep increasing for all technologies, leading to a decline in final energy demand for transport by 37%.

Keeping coal power generation in the system longer than 2030 will not only keep GHG emissions higher for a longer time, but also make the transition more difficult in the later steps, as it delays the deployment of renewables by about 5 years.[10] In such a delayed scenario, only half as much PV and onshore wind capacities would be built in 2021-2030, which would need to be compensated for in the years after 2030 when direct and indirect electrification would intensify. In this scenario, keeping some existing nuclear power plants in the system after 2030 could support a smoother coal phase-out, with less gas capacities used in 2030, while a faster renewables ramp or stronger effort on energy efficiency would be another option. However, the nuclear option does not change the long-term picture: nuclear new builds and lifetime extension projects are likely to be more expensive than renewables as soon as 2025. A slower electrification rate in the transport and building sectors would also keep emissions higher for a longer time; increasing the need for synthetic fuels in those sectors would not tap the full cost-effective potential of direct electrification.

Step 2: Reduce GHG emissions by 90% in 2045 relative to 2010

Large efforts are needed in this second step of the transition to prolong the emissions reductions achieved in the first step, while the emissions will get more difficult and costly to abate if not planned properly. By 2045, coal, oil and fossil gas consumption in the energy conversion, transport, building sectors will need to be reduced drastically, as well as in all the segments of the industrial sector that allow it at reasonable cost. Electrification will continue across all sectors, directly where possible and indirectly using sustainable hydrogen and other synthetic fuels. Hydrogen will also be increasingly used as a raw material in the industrial sector. Efficiency improvements remain important to help reduce emissions in all economic sectors. By 2045, electrification and defossilization added with a decrease in final energy consumption (due to efficiency gains and population decline) will lead to a decline in primary energy demand by 51% (from 2020). This step will require proper planning early on for the necessary technologies to be available at the lowest possible cost.

The **energy conversion sector** will remain a key sector to decarbonize. Electrification and increased hydrogen production will raise power consumption by 30% mostly for heat production (industry and building sectors), reaching about 1 300 TWh by 2045. Renewables will continue to expand to reach a share of 98% in the power mix at this time horizon. To cover the demand, PV will be installed massively, as being the cheapest local source, and almost reaches the technical capacity limit of 524 GW assumed in this study (utility-scale installations use1.3% of total available land area assumed in this study). 73 GW of onshore wind will be installed, a large share of it in the windy eastern regions (62% of installed capacities in Hokkaido and Tohoku). Wind power will be mostly exported to other more densely populated and industrialized regions, implying a significant increase in grid interconnections between regions. Also, 44 GW of offshore wind capacities are installed by 2045, which will be built close to load centers in the central part of the country. The net annual installed capacity between 2031 and 2045 is then 25 GW of PV, 3.9 GW of onshore wind, and 2.5 GW of offshore wind. Imports of renewable power from Russia and Korea/China could reduce the need for local renewable generation and add some flexibility to the system, though the benefit will remain marginal as market prices in Japan will remain low. Also, decentralized solutions closer to the consumption centers are a favorable option, especially PV with storage, to avoid costly and restrictive grid expansion.

[10] A rather conservative CO_2 price of 2 519 ¥/tCO_2 (about 23 US$/t$CO_2$) was assumed in 2030 in this sensitivity analysis (compared to 265 ¥/tCO_2, 2.4 US$/t$CO_2$ in 2020). The lower the CO_2 price, the stronger the effect will be, coal power generation remaining competitive in the market.

The **industrial sector** achieves the largest emissions reduction during this period (-158 Mt CO_2eq), by continuing to electrify low and medium temperature heat and using synthetic hydrogen and methane in high temperature industrial processes after 2035 to gradually replace fossil fuels. The use of biomass in Japan will be very limited due to very restricted resource availability for sustainable biomass.[11]

The **building sector** is the first sector to completely decarbonize: thanks to the continued efforts made already in the 2020s, demand will be electrified by 2040 with heat pumps and direct electric heating systems that are the most cost-efficient solution for low temperature heat needs (such as heating, cooling and hot water). Old buildings will further receive energy efficient retrofits and new dwellings will comply with strict energy efficiency standards.

The **transport sector** sees limited change in mobility trends. Electrification continues, especially in road transport with close to 45 million electric vehicles by 2045. Where direct electrification is difficult, indirect electrification will be needed through electricity-based decarbonized synthetic fuels such as green hydrogen, synthetic methane, and mostly Fischer-Tropsch (FT) fuels, particularly for maritime transport and aviation. Demand for sustainable e-fuels in transport kicks in from 2035 onwards, mostly FT fuels that will be imported due to their very high cost if locally produced (total consumption 83 TWh by 2045, more than three-quarters of which is imported).

Step 3: Increased use of green synthetic fuels in the last step to eliminate residual emissions, mostly in industry

The emissions still emitted in 2045 are the hardest to abate, typically in the industrial sector but also in the transport sector (aviation and maritime transport). Abating those emissions will drive further the demand for e-fuels, specifically synthetic hydrogen and methane. In 2050, heat demand for high temperature industrial processes is supplied by e-fuels, while medium temperature industrial heat demand is covered by industrial scale heat pumps, direct electric heating, and very limited sustainable biomass. Hydrogen will play a very limited role in the transport sector, which will mostly use FT fuels (more than three quarters of which – 89 TWh – will be imported).

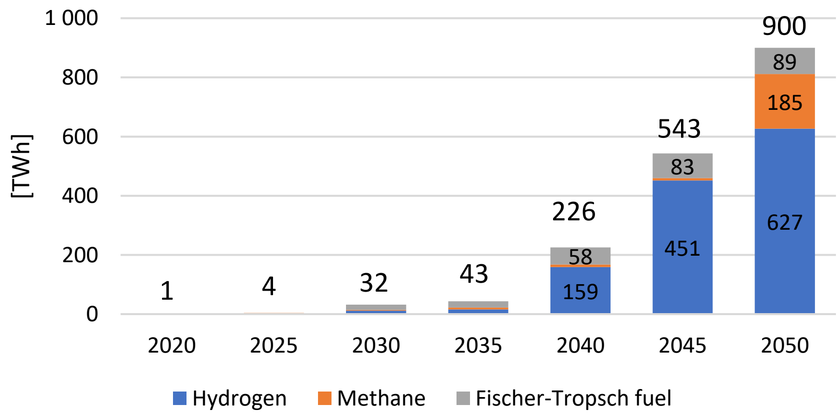


Figure 4: Base Policy Scenario with imports – evolution of synthetic fuel consumption from 2020 to 2050.

[11] Sustainable biomass includes residues from agriculture and forestry, construction wood wastes, biowastes, sludge and municipal wastes, excluding recyclable fractions like plastics, paper, cardboard. The assumptions on resources potential are based on data from the Food and Agriculture Organization of the United Nations (for agriculture and forestry residues) and from the World Bank (for waste potential).

A significant amount of sustainable hydrogen and methane will thus be needed to supply mostly the industry (600 TWh of hydrogen and 185 TWh of methane in 2050, up from 420 TWh of hydrogen and 8 TWh of methane in 2045). Green hydrogen produced domestically is expected to reach 3 TWh in 2030 (~77 000 t in high heating value), up to 68 TWh in 2040 (~2 Mt) and 353 TWh in 2050 (9 Mt), while about the same amount will be imported after 2035. By 2050, 30% of all generated power will go into hydrogen production (430 TWh).

Most of the renewable power to supply the electrolyzers will come from onshore wind power produced in the eastern regions (68% of installed onshore wind capacities are in Hokkaido and Tohoku) and transported to the regions where electrolyzers will be built, namely in Tokyo and the other central regions. 73 GW_{el} of electrolyzers will be needed by 2050 to produce 350 TWh of hydrogen. Such a strategy would require a substantial grid deployment program to directly connect the Hokkaido and Tokyo regions electrically (17 GW of direct grid connection between the two regions in 2050). Offshore wind will be of secondary importance because of its higher costs, but it could play a more important role if costs declined.

Importing about half of the necessary sustainable e-fuels limits both the pressure on resource availability in Japan and on total system costs, in particular for heat generation. Even in the scenario where Japan imports power and most of its synthetic fuels, the energy system mix would have 68% local resources (against only 12% today). This transformation strategy would therefore enhance significantly the country's energy security.

Direct Air Capture (DAC) units are used to a very limited extent to produce synthetic fuels, not for CCS purposes. Conventional power plants fitted with CCS have high relative cost and hence play a negligible role in reducing energy-related emissions. The energy sector thus reaches carbon neutrality solely by means of defossilization and emission abatement. This study does not consider non-energy related emissions, which are considered difficult to decarbonize (non-energetic industrial process emissions, agriculture, waste); here, DAC and CCS could come into play.

This renewable decarbonized energy system can be built in Japan by 2050 at a reasonable cost, with total system costs about 30% lower in 2050 than in 2020. Currently, Japan spends about 17 trillion ¥ (154 b$) yearly in fossil fuel imports,[12] representing the largest share of the national energy system costs and 22% of imports in value. According to the model, annual system costs decline significantly from around 24.7 trillion ¥ (225 b$) in 2020 to about 17.4 trillion ¥ (159 b$) in 2050 after a slight increase in 2030. This spending represents about 3% of the current GDP in 2050. Instead of being spent on energy imports, the money goes predominantly into the national economy; only 4.5 trillion ¥ (41 b$) goes into synthetic fuel import in 2050. Capital investments in power and heat generation, energy storage, transmission grids and fuel synthesis technologies throughout the transition reach 3.6 trillion ¥ (33 b$) per year, representing about 2.5% of current gross investment levels.[13] However, these investments are not evenly spread over the transition period: the later the transition, the later the investments have to be made at once, which makes the transition less realizable. Renewables remain a favored technology due to a significant cost decrease, especially in the next 10 years. New nuclear power plants, except the two units under construction (Ohma and Shimane), are not installed in the scenarios due to high costs.[14]

[12] Data for 2019 from Japan foreign trade council Inc, Foreign Trade 2020, 31.03.2020.
[13] Gross fixed capital formation (GFCF) for 2019 estimated at 146 017 b¥ by the OECD (https://data.oecd.org/gdp/investment-gfcf.htm).
[14] The possibility of a life-time extension of nuclear (up to 60 years of technical lifetime) was not taken into account in this study. Other studies (REI 2020, Agora 2020) show that retrofitting nuclear power plants could be more expensive than renewable projects as soon as 2025.

III. Three pillars of the transition to climate neutrality

Pillar 1: Energy efficiency and the reduction of energy demand

The population decline projected in Japan (-20%) was assumed to reduce final energy consumption steadily from 2020 to 2050. In terms of primary energy, electrification and defossilization reduce demand by 34% due to efficiency improvements: on the supply side, 19% thanks to renewables-based electrification; and 15% on the demand side, mostly due to the electrification of the transport sector and increased motor efficiency. Overall, primary energy demand declines by 54% during the transition from 4 600 TWh in 2020 (16 700 PJ) to about 2 100 TWh (7 700 PJ) in 2050.

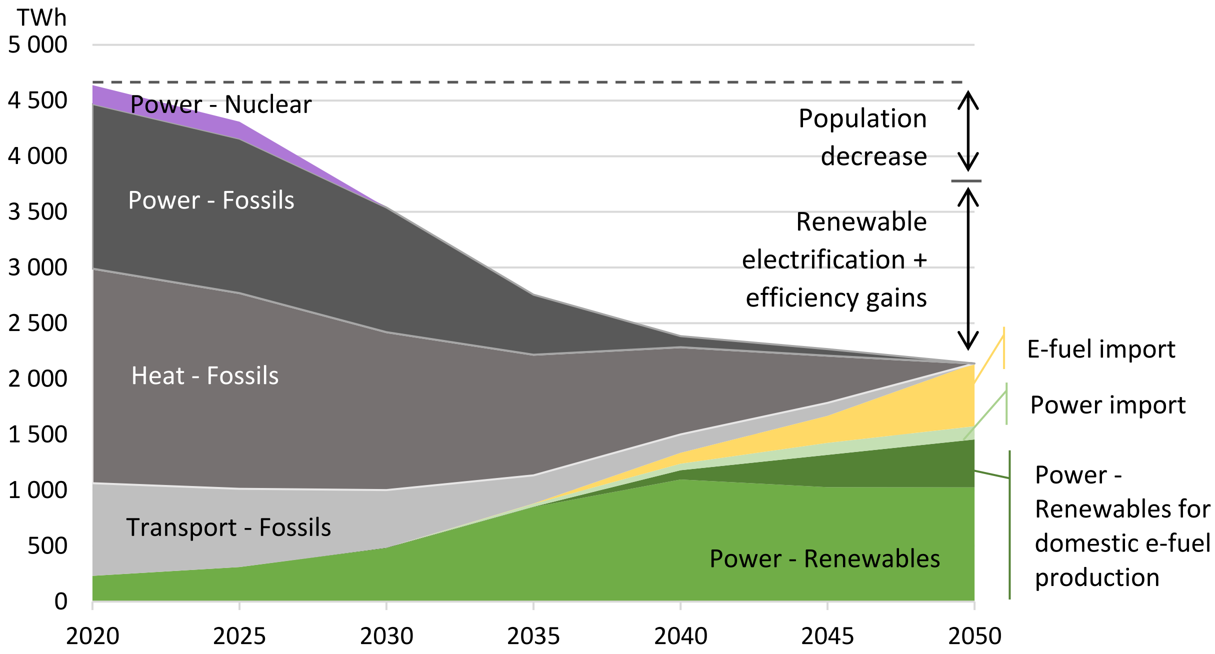


Figure 5: Base Policy Scenario with imports – evolution of primary energy demand from 2020 to 2050.

In the building sector, the increasing use of heat pumps to generate space heating and hot water will reduce fuel consumption through the use of ambient heat. Efficient heat pumps and appliances also need to replace older, less efficient devices. In the energy conversion sector, the deployment of renewable electricity increases the efficiency of power generation by replacing thermal power plants that have high conversion losses. In 2050, most electricity will be generated by wind and PV, which have no conversion losses (the secondary energy carrier, electricity, is primary energy). Only about 1.5% of power generation will be based on combustion fuels, two-thirds of which will be biomethane from waste and residues and one-third hydrogen.

In the transport sector, more efficient electric vehicles will increasingly replace combustion engine vehicles. And in the industrial sector, the broader use of more efficient technologies, notably electric furnaces, will further reduce primary energy demand. In addition, especially in the basic materials industry, the development of the circular economy will make good use of secondary materials, which entail much less energy than producing primary material does – though this aspect was not analyzed in this study.

Final demand reduction was assumed to be moderate, mostly following the trend in population decline. In all sectors, demand could decline more quickly if proactive measures were taken already today.

Pillar 2: Defossilization, renewable power generation and electrification

The importance of electricity and especially renewable power will grow during the transition. In many applications, especially in transport, space heating, cooling and hot water, the use of electricity proves to be the most efficient solution, especially compared with combustion engines and boilers. Wherever possible, direct electrification must be pursued in transport, space heating and industrial processes as the most efficient use of primary energy. Indirect electrification through the use of sustainable synthetic fuels will remain more expensive and should be reserved to cases where direct electrification is not feasible. Without electrification and defossilization of the power, heat and transport sectors, the Japanese energy system's primary energy demand (PED) would be 74% higher in 2050.

Power demand increases significantly by 2050 mostly due to the production of e-fuels, although their use is limited to the necessary minimum and about 50% is imported. In a scenario with about 50% imported e-fuels, electricity demand increases by 50% (Figure 6). This increase would reach up to +115% if all the synthetic fuels were produced domestically.

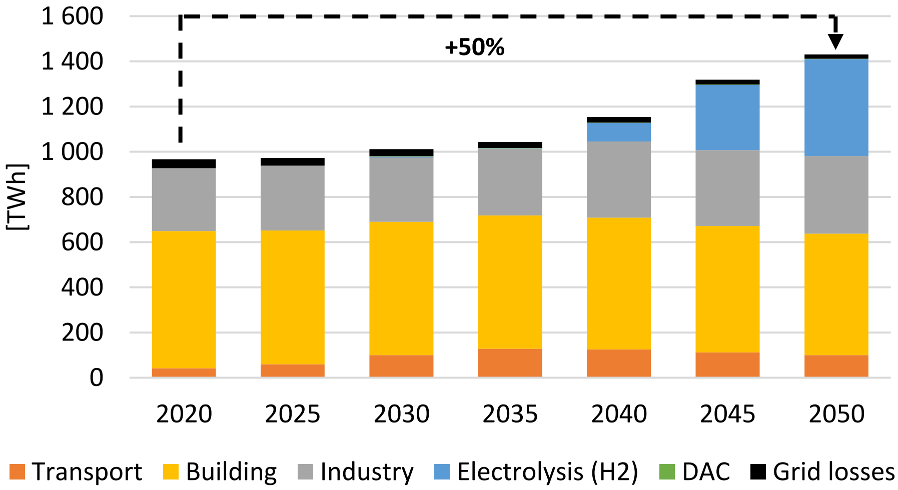


Figure 6: Base Policy Scenario with imports – evolution of gross power consumption from 2020 to 2050.

In order to achieve climate neutrality, this demand has to be met as soon as possible by sustainable power. Coal power is phased out by 2030 while oil-fired power plants are put on cold reserve; by 2050 gas-based generation switches to e-fuels. Demand is covered increasingly by renewables during the transition to reach 100% by 2050. Only about 1.5% of power generation will be based on combustion fuels replacing fossil fuels, mainly biomethane and green hydrogen. Generation from renewable sources more than doubles from 185 TWh in 2019 to 400 TWh in 2030, and from there more than triples to 1 350 TWh in 2050.

PV becomes the main source of power as its cost is expected to decline substantially in Japan, reaching on average 3.9 ¥/kWh (35 $/MWh) in 2050. By 2030, installed PV capacity more than doubles (144 GW), and the maximum technical potential set in this study is reached by 2050 in all the modelled scenarios (524 GW). By 2050, a little over one third of installed capacity is held by prosumers, who play a significant role in minimizing the cost of grid reinforcement. Onshore and offshore wind are installed less (88 GW and 63 GW, respectively, in 2050) but contribute significantly to total power generation (given their higher capacity factor). On average, the annually installed capacity required is about 8.4 GW of PV, 1.5 GW of onshore wind, and 0.7 GW of offshore wind between 2021 and 2030, and of 20 GW of PV, 3.7 GW of onshore wind, and 2.8 GW of offshore wind between 2031 and 2050. As a comparison, 2015 was the most successful year for PV installations in Japan with almost 11 GW installed compared to 6.5 GW in 2018.[15]

PV combined with short-term storage covers most local power demand, whereas wind energy is largely transported from the eastern regions to the central ones, which are more densely populated and more concentrated in industrial demand. New grid connections are then also needed, doubling from the currently available 40 GW. A new direct connection from Hokkaido to the densely populated Tokyo area is profitable.[16]

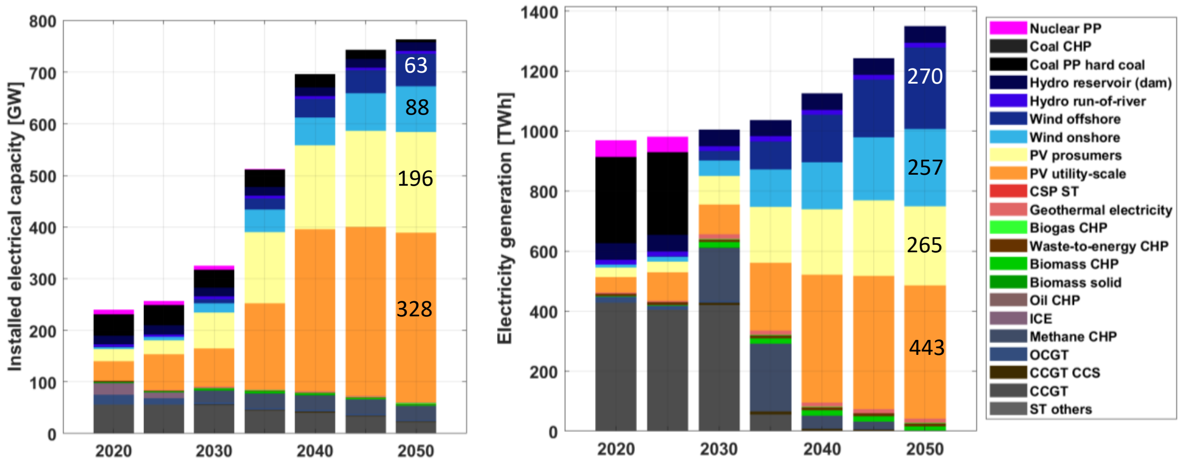


Figure 7: Base Policy Scenario with imports – evolution of power generation capacity (left) and generation (right) from 2020 to 2050.

To integrate those high levels of renewables and keep the system balanced at all times, the electricity system will have to become significantly more flexible – through more battery storage, the deployment of heat pumps, electrolyzers and electric vehicles (notably with smart charging and vehicle-to-grid or V2G technologies), and through more electricity trading between regions. The spatial and temporal distribution of generation will balance variable generation and enable the efficient use of renewable electricity, while the remaining conventional gas power plants fill in gaps.[17] The short-term balancing of electricity demand and supply will take place primarily through short-term storage (battery storage, smart charging and vehicle-to-grid technologies), load management and electricity trading. Seasonal variations in electricity supply will be primarily balanced through the generation and reconversion of synthetic methane (power-to-gas and gas-to-power) made with wind power from the northern regions, although this option will not be required much thanks to the flexibility offered by the import of synthetic fuels.

In 2050, the overall system capacity exceeds 750 GW (including VRE and flexible generation), and flexible demand adjusts to the generation profile of variable renewables. Since massive flexible

[15] https://www.irena.org/publications/2019/Mar/Renewable-Capacity-Statistics-2019
[16] In 2020, the grids are used according to existing net transfer capacity (NTC) limits (about 50%), but later the NTC limits are considered to be relaxed to a grid utilization capacity factor (CF) of 80%. Even if the NTC is kept at 50% until 2050, the impact of the necessary additional grids on LCOE remains at about 4% of total LCOE.
[17] Those gas power plants are switched to run on green hydrogen or synthetic methane in 2050.

demand exists, the peak load will vary from about 84 GW during hours of low renewable power production, mostly in summer at night ("dark doldrums") to about 490 GW in winter at midday, when PV and wind feed-in are high. Flexible demand (storage, V2G charging, power-to-mobility, power-to-heat, power-to-fuels) is activated during those high PV and wind feed-in times, pushing up the maximal load and resulting in a rather low curtailment level of renewables (1.1% of total power generation). Inflexible demand can be met by flexible energy sources available in sufficient amounts such as hydro dams, pumped-hydro storage, gas turbines and gas CHP running on biogas and e-fuels, biomass power plants and CHP, battery storage, as well as some wind capacity generating during every hour.

Pillar 3: Hydrogen and sustainable synthetic fuels

The complete defossilization of transport and industrial processes requires substantial volumes of green synthetic fuels to substitute fossil fuels in hard-to-abate segments such as high temperature heat in industry, heavy-duty vehicle goods transport, maritime transport and aviation. Synthetic methane and most hydrogen is used in the industrial sector, while Fischer–Tropsch (FT) fuels are used in the transport sector. The slower the electrification of the transport sector, the more FT fuels are required during the transition. In the modelled scenarios, hydrogen represents about 65-75% of all synthetic fuels; the industry sector consumes about 80-90% of those synthetic fuels.

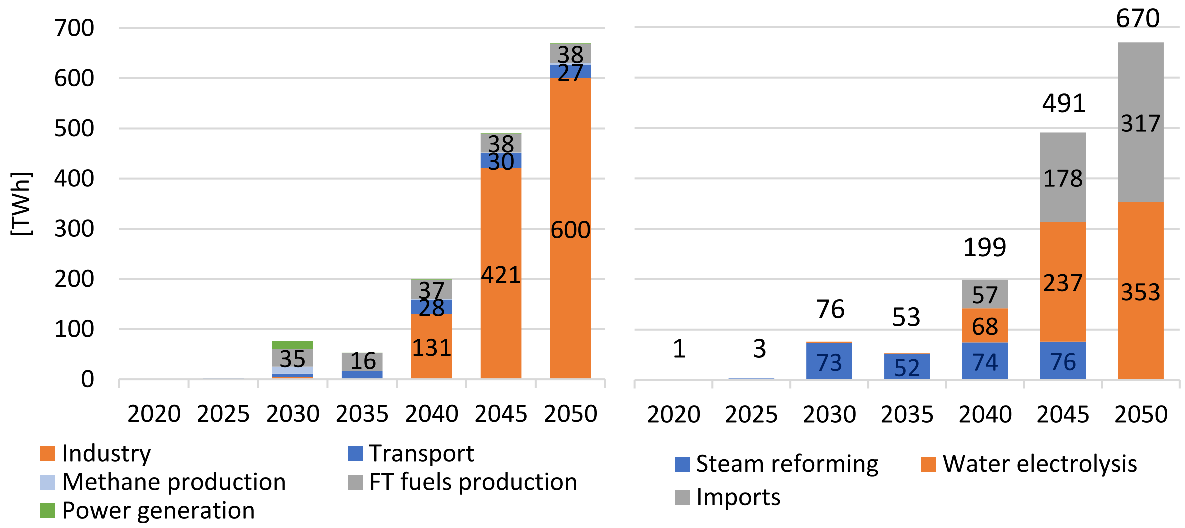


Figure 8: Base Policy Scenario with imports – evolution of hydrogen demand (left) and supply (right) from 2020 to 2050.

As electricity-based energy carriers, synthetic fuels are more expensive than electricity and can compete with fossil fuels only if carbon prices reach very high levels of about 36 000-60 000 ¥/tCO_2eq (330-550 $/t$CO_2$eq). Even if the use of hydrogen is limited to the most hard-to-abate sectors, hydrogen demand rises to about 670 TWh by 2050 in all the scenarios, amounting to about 17 Mt of hydrogen.[18] 600 TWh of hydrogen is used in the industrial sector, 37 TWh to produce e-fuels for the transport sector, especially aviation and maritime transport. Some more is needed to produce synthetic methane for use as fuel in gas turbines.

[18] As a result of the cost-optimization, hydrogen is consumed in sectors where less expensive direct electrification is not an option. Given the sectorial perimeters set for the modelling, the real total demand for hydrogen could be subject to decreasing factors (for example, material recycling is not included in this study) and increasing factors (the chemical sector is not included in this study).

The current hydrogen strategy in Japan foresees a demand of 5 to 10 Mt "in the future", mostly to be used in power plants. This study shows that hydrogen will need to be used very sparingly as it will not be available massively; its use in power plants will be limited (to about 42 kt in 2050); direct electrification should be prioritized wherever possible. Ways to reduce the need for synthetic fuels will need to be explored, such as material circularity.

Synthetic fuels will certainly need to be imported to reduce pressure on the Japanese energy system. Indeed, 3.5 TWh of power is needed to produce 2.8 TWh of hydrogen in 2030, which translates to 430 TWh of electricity by 2050 for the domestic production of 350 TWh of hydrogen. It is possible for Japan to produce almost all its synthetic fuel demand domestically.[19] However, this volume of domestic synfuel would require about 190 GW more wind generation capacity (compared to a scenario with about 50% imported synthetic fuels) and 100 GW more grid interconnection between wind farms (mostly in the north) and load centers[20]; low-cost PV is assumed to have reached its space limitations. Such a scenario would put a strain on land availability and increase the cost of heat production in Japan. The cost increase will also vary according to trends in the cost of electrolysis in Japan, which in turn will depend on how proactively the local electrolyzer industry is developed there and on how quickly low-cost electrolyzers are imported.

IV. Recommendations

- Climate neutrality based on renewables is technically and economically possible in Japan. Investments should be part of a comprehensive program to boost economic growth and move the economy towards climate neutrality, as part of the Japanese Green Growth strategy.
- Japan has to kick-start enhanced climate action as soon as possible. Its 2030 target must be increased to reach a 45% GHG emissions reduction (relative to 2010) and targeted actions adopted in all sectors of the economy. The renewable energy target in power generation should be increased to at least 40% of the power mix by 2030, accompanied by a comprehensive policy package to drive investments in renewables. Electrification needs to be accelerated, notably through the deployment of heat pumps and electric vehicles (EVs). Market access of those technologies must be guaranteed through better regulation and incentives, such as for the deployment of EV charging infrastructure. Improvements in energy efficiency must be supported with ambitious building standards and stringer regulation for vehicles. A realistic coal phase-out plan by 2030 should be defined. The current hydrogen strategy should be refined to focus the use of hydrogen on sectors where CO_2 emissions are most difficult to abate and where direct electrification is not an alternative. The development of green hydrogen infrastructures (domestic and imported) should be concretized.
- In order to accelerate the green transition in the energy, industrial, transport and building sectors, Japan will need a mix of instruments that combines market-based incentives, targeted support mechanisms and regulatory policies. Energy taxes, levies and duties will have to be reformed and carbon pricing increased, as existing price structures tend to promote oil, coal and gas and impede the use of renewable electricity. The upcoming discussions on the 6th Strategic Energy Plan will be crucial to this end.

[19] Only a small amount of FT fuels can still be imported in this scenario, leading to about 3% of primary energy demand imported to Japan in 2050, compared to 90% today.
[20] The model considers it more cost-effective to transport electricity close to where synthetic fuels are needed and to produce them there, rather than installing the electrolyzers close to power generation sources and transporting, say, green hydrogen or methane in converted gas grids.

- Government action starting now will determine how Japan goes about achieving climate neutrality by 2050 and a 45% reduction in GHG emissions by 2030. Intelligent policy instruments will be needed to make the Japanese economy sustainable and resilient. This transformation will need to ensure that structural changes are as fair and inclusive as possible.

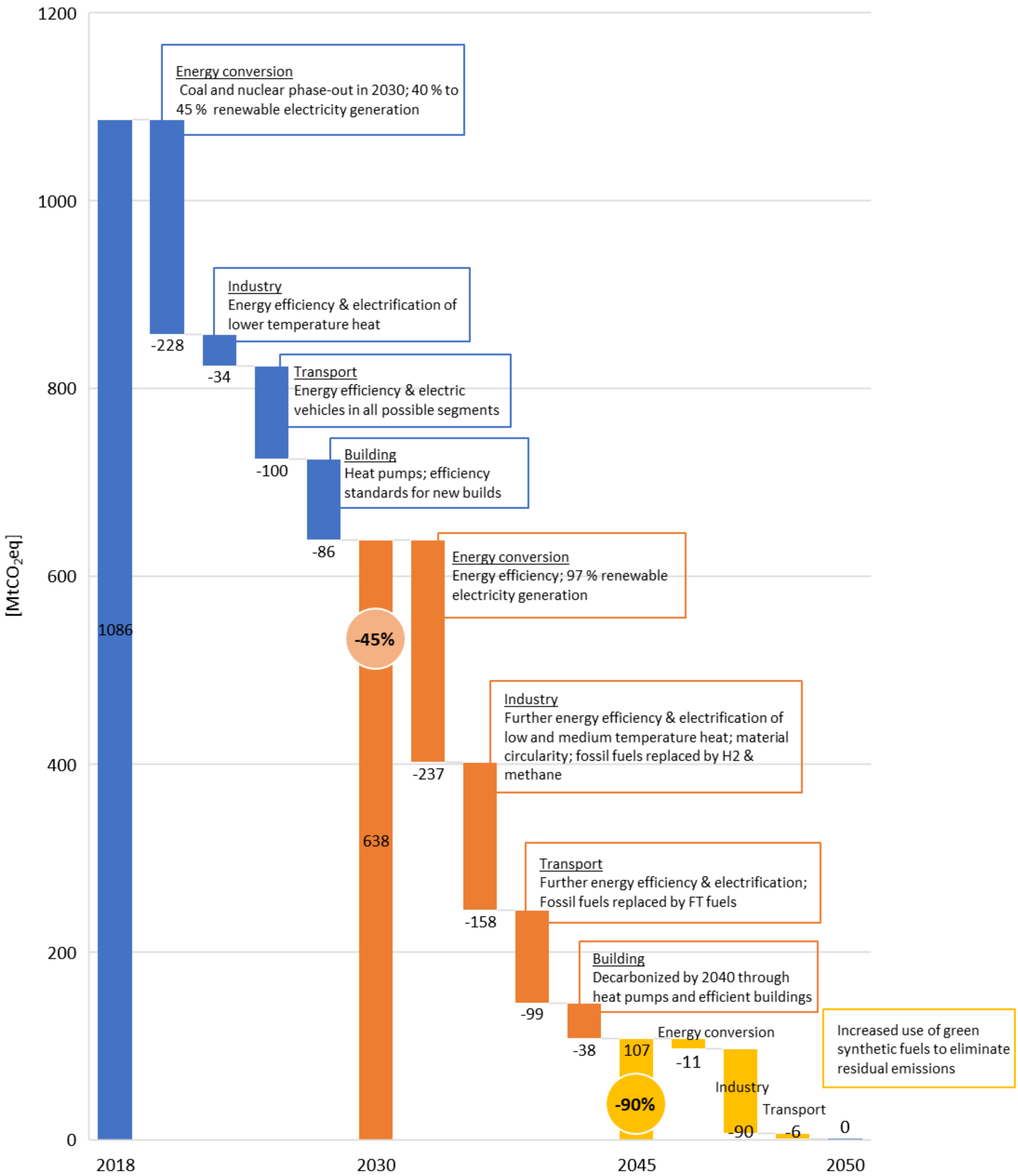


Figure 9: Three steps towards climate neutrality in the BPS imports scenario (GHG emissions in $MtCO_2eq$)

		2020	2030	2050	2030/2020 % change	2050/2020 % change
Energy-related GHG emissions (Mt CO_2eq)	**Total**	**1 045**	**638**	**-**	**-39%**	**-100%**
	Energy conversion	443	248	-	-44%	-100%
	Industry	281	247	-	-12%	-100%
	Buildings	119	38	-	-68%	-100%
	Transport	203	105	-	-48%	-100%
Primary energy consumption (PJ)	**Total**	**16 694**	**12 742**	**7 698**	**-24%**	**-54%**
	Coal	4 843	1 073	-	-78%	-100%
	Oil	3 001	1 604	-	-47%	-100%
	Gas	7 406	8 320	-	12%	-100%
	Nuclear	611	-	-	-100%	-100%
	Renewables	833	1 745	7 698	+109%	+824%
Electricity						
	Gross electricity consumption (TWh_{el})	962	1 009	1 430	+5%	+49%
	Gross electricity generation (TWh_{el})	970	1 021	1 351	+5%	+39%
	Renewable share in generation (%)	18	39	100	+113%	+453%
	Onshore wind capacity (GW)	4	18	88	+361%	+2 168%
	Offshore wind capacity (GW)	0	7	63	+12 155%	+105 048%
	Solar PV capacity (GW)	61	144	524	+134%	+752%
	Number of electric vehicles (M)	1	12	44	+908%	+3 480%
	Heat pumps (GW_{th})	46	89	142	+92%	+207%
Synthetic fuels demand (TWh_{th})	**Total**	**1**	**106**	**947**	**+7 507%**	**+67 906%**
	Hydrogen (TWh_{th})	1	76	670	+5 360%	+48 034%
	Share of import	-	-	*47%*		
	SNG (TWh_{th})	-	12	188		
	Share of import	-	-	*94%*		
	FT (TWh_{th})	-	18	89		
	Share of import	-	-	*78%*		
	Domestic electrolyzer capacity (GW_{el})	-	1	73		
	Power input for green H2 production (share of power generation) (%)	-	*0.3%*	*32%*		
	Population in Japan (M)	125	117	100		
	CO_2 price (JPY/t_{CO2})	289	5 496	18 000		

Figure 10: Base Policy Scenario with imports at a glance

1. Introduction

1.1. Overview of the current energy system

The current energy system of Japan strongly depends on fossil fuels. According to the latest statistics of the Ministry of Economy, Trade and Industry (METI) for 2019, renewable energy, including biofuels, hydropower, solar photovoltaics (PV), wind, solar thermal and geothermal contributed 9.3% to the total primary energy supply of Japan [1]. At the same time, energy system is highly dependent on energy imports, as only 12% of the energy supply is covered by local resources [2]. Coal, despite its severe negative environmental impact, still plays an important role in the total energy supply with a share of 25.4% and provides about one third of total electricity supply. The share of renewables in electricity supply reached 18% in 2019 and has been gradually increasing in recent years. The structure of the total energy supply and electricity generation in 2019 according to the METI statistics is presented in Figure 1.1.

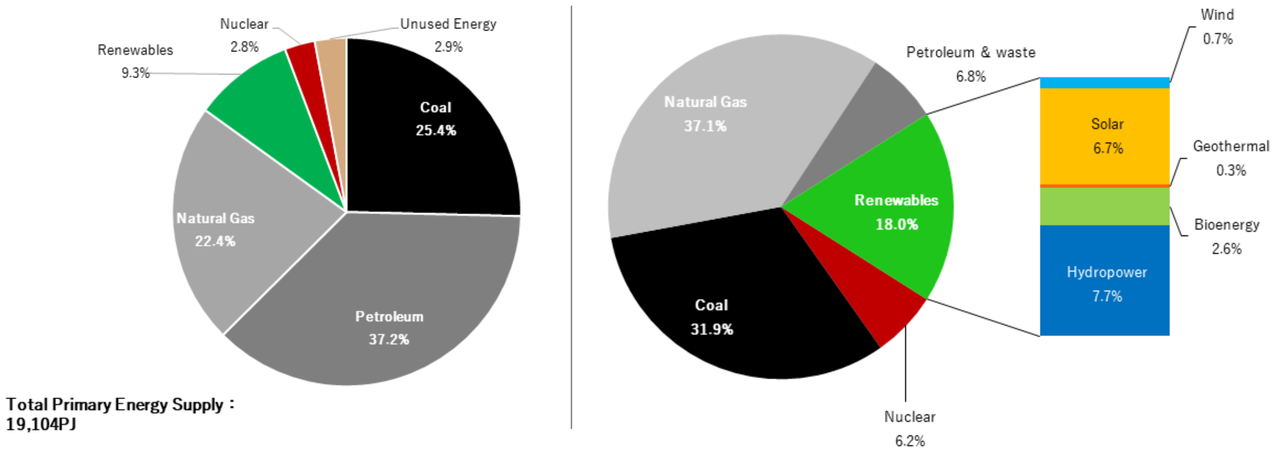


Figure 1.1. Total energy supply (left) and total electricity generation (right) in 2019 [1].

The structure of electricity supply has been changing during the last 10 years with a fast introduction of renewable energy (RE) - about 64 GW of solar PV, hydropower and wind capacities have been installed in the past 10 years - and additional gas power plant capacities, compensating the sharp decrease of nuclear power generation as a consequence of the Fukushima disaster. The construction of coal power plants that had almost stopped after peaking in the early 2000s has been restarted. About 4.4 GW of new coal power generation capacities have been commissioned since 2011, and a pipeline of 9 GW of new coal powerplants is currently under construction or in planning (7.3 GW under construction and 1.9 GW in planning) which will increase the dependency of the Japanese energy system on coal.

In 2018, the industry sector had the highest share of final energy consumption in Japan (46.6%), followed by transport (23.4%), commercial (16.1%) and residential sectors (14%) [2]. The industrial sector relies on fossil fuels for about 78% of its energy consumption (direct use of coal, oil and gas as well as indirect use through use of steam). In the residential and commercial sectors, 57% and 45%

respectively of final energy consumption went into heating, cooling and hot water,[21] and about 8-9% to cooking [2]. The direct use of fossil fuels (essentially natural gas and oil) represented 48% and 42% of final energy consumption respectively, which shows they are still widely used in space heating and hot water, although electric heating and especially heat pumps already represent a notable share of space heating demand, benefiting from favorable developments in costs and efficiency.

In the transport sector, rail transport is mostly electrified, while road, maritime and aviation transport modes mostly depend on fossil fuels (98%). Current trends show road transport is being slowly electrified, with hybrid electric vehicles already representing a significant market share (about 33.7% of new sales in 2018 [4]). Maritime transport and aviation have not seen changes in the past years.

1.2. Ongoing transition: progress, targets and limitations

The current NDC targets a decrease in GHG emissions by 26% until 2030 relative to 2013 levels. The Prime Minister announced in October 2020 a new long-term target for Japan to reach climate neutrality by 2050. The rate of defossilization should accelerate to reach this carbon neutrality target in 2050, and to limit cumulative GHG emissions to a level compatible with the ambitious 1.5°C target of the Paris Agreement.

It is often debated that renewable technologies are expensive, and that Japan does not have enough land to massively deploy these renewable technologies. Though, this is also the case for all the generation technologies, renewable technologies are still significantly more costly in Japan than in the global market and in the regions such as Europe, China, and India, where significant progress has been made. Land space is also scarce in general in the country. Proposals have been made to quickly decrease the cost thanks to a reform of the power market design or the adaptation of regulations notably for grid access and simplifying access to land, especially exhausted farmlands or land that are used for agriculture that could also host wind turbines. The potential for prosumer solar PV installing solar cells onto roofs has also not yet been tapped into, and the country has a large potential for offshore wind if costs were to decline enough.

In a joint project, LUT University, the Renewable Energy Institute (REI) and Agora Energiewende have analyzed several pathways for Japan to achieve climate neutrality by 2050 based on renewables in the sectors emitting energy related GHG, representing about 88% of all GHG emissions today: energy conversion (38%), transport (17%), building (10%) and industry (23%). Non-energy related greenhouse gas emissions (some industrial process emissions, agriculture, and waste) were not considered. Stakeholder meetings were organized with the main stakeholders involved in the energy debate in Japan in order to review the assumptions and discuss the preliminary results.

The next sections go through the methodology, the scenarios and assumptions, followed by the main trends and insights of the energy system transition in the power, heating and cooling, and transport sectors. The role of different techno-economic elements is highlighted such as storage, grids, sector integration, energy imports and their impact on total energy system cost.

[21] It is interesting to note in this context that final energy consumption per household in Japan is almost half as high as in Western European countries such as Germany. The Japanese households use much less energy for heating especially, leading to a share of electric appliances and lighting of 34%, and 57% for hot water (28.5%), and heating and cooling (28.5%). In Germany, 84% of household energy consumption goes into space heating (68%) and hot water (16%) [3].

2. Methodology

The energy system has been modelled with the LUT Energy System Transition Model, covering the energy conversion, residential and commercial, industry and transport sectors. These sectors are modelled in 3 categories of energy use: power, heat and transport, and all their GHG emissions are accounted for. The cost-optimized modelling was conducted in 5-year steps, in hourly resolution to ensure the supply-demand balance at each hour. More detailed explanation is presented below.

2.1. LUT Energy System Transition Model

The LUT Energy System Transition model [5,6] is applied across an integrated energy system covering demand from the power, heat and transport sectors as shown in Figure 2.1. The unique features of the model enable to draw cost optimal energy system transition pathways with a high level of geo-spatial and temporal resolution. Furthermore, the capability to model in an hourly resolution for an entire year enables uncovering crucial insights particularly, with respect to storage and flexibility options, most relevant for the future energy systems.

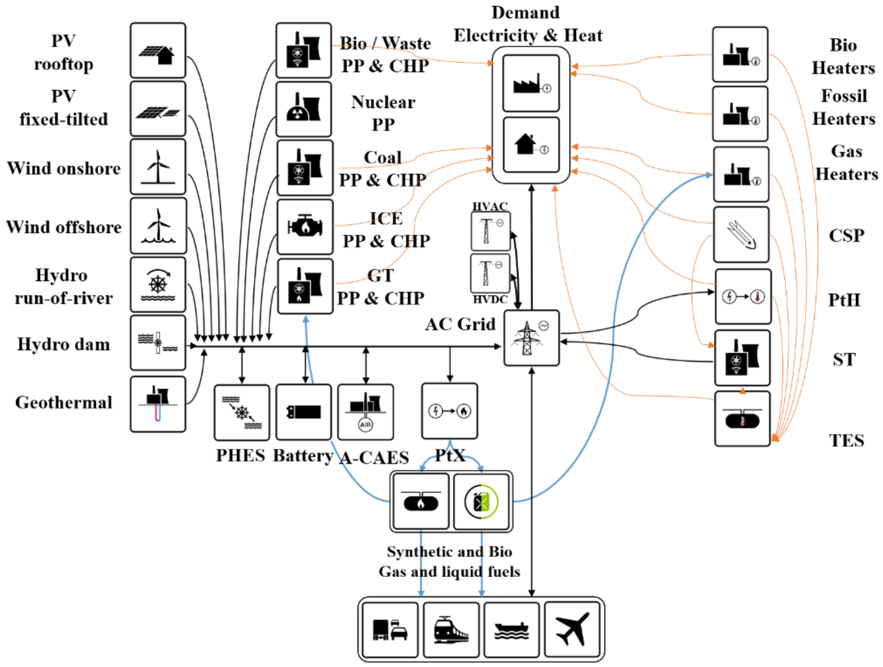


Figure 2.1: Schematic representation of the LUT Energy System Transition model. Abbreviations can be found in the Nomenclature section.

In order to take into account the potential of prosumer PV for the transition of the energy system, the simulations are carried out in a 2-stage approach. In the first step (Prosumers modelling), the model determines the introduction of prosumer PV and battery storage capacities and the transition of individual heating systems for space and water heating. In the second step (centralized energy system modelling), the transition of the centralized power system, industrial heat and transport sector is simulated.

First step: Prosumers modelling

In the model, residential, commercial and industrial PV prosumers can install their own rooftop PV systems either with or without lithium-ion batteries. PV prosumers can also draw power from the grid when they need it, while they can also feed-in surplus electricity to the grid. The model defines the optimal structure of power and heat supply considering the existing capacities, the investment costs of new and existing installations and their operational costs to balance supply and demand for each hour. As such, electricity for residential domestic hot water and space heating can be bought from the grid or supplied by own PV capacity, where applicable. Space heating demand varies across the different regions of Japan depending on climatic and weather conditions, for each region an individual climate related space heating demand profile is applied. A partial self-supply from rooftop PV systems to cover electricity demand of individual heat pumps and heating rod systems is also possible if it is economically viable for prosumers.

The target function for the prosumers is the minimization of the cost of consumed electricity and heat, calculated as the sum of self-generation annual costs, costs of fuels for heating and the cost of electricity consumed from the grid, minus the cost of electricity sold to the grid.

Second step: Energy system modelling

The model has integrated all crucial aspects of the power, heat and transport sector demands, while the non-energetic feedstock for industry, as well as non-energy related greenhouse gas emissions (in particular those from the agriculture sector) are not included (see remark above). For every time step, the model defines a cost-optimal energy system structure and operation mode for a given set of constraints: power demand, process heat demand for industry, space and domestic water heating. The model aims to minimize the total system cost.

The technologies modelled are:
- electricity generation technologies: renewable energy (RE), fossil, and nuclear technologies;
- heat generation technologies: renewable and fossil;
- energy storage technologies: electricity and heat storage technologies;
- Power-to-Fuel technologies: sustainable synthetic fuel production (also referred to as e-fuels in this report);
- electricity transmission technologies.

A more detailed overview of the model is available in the Appendix, based on Bogdanov et al. [5] and Child et al. [6].

2.2. Model Setup and the Japanese energy system structure for the study

The energy system transition has been carried out for Japan, divided into nine regions according to the main electric utility companies' supply areas. As the borders can differ from the ones applied in general statistics, the prefectures included in each of the nine regions are listed below:

- Hokkaido: Hokkaido
- Tohoku: Aomori, Akita, Iwate, Fukushima, Miyagi, Niigata, Yamagata;
- Tokyo: Chiba, Gunma, Ibaraki, Kanagawa, Saitama, Tochigi, Tokyo, Yamanashi, Shizuoka (partially);

- Hokuriku: Fukui, Ishikawa, Toyama;
- Chubu: Aichi, Gifu, Mie, Nagano, Shizuoka (partially);
- Kansai: Hyogo, Kyoto, Nara, Osaka, Shiga, Wakayama;
- Chugoku: Hiroshima, Okayama, Shimane, Tottori, Yamaguchi;
- Shikoku: Ehime, Kagawa, Kochi, Tokushima;
- Kyushu: Fukuoka, Kagoshima, Kumamoto, Miyazaki, Nagasaki, Oita, Saga;

The isolated grid of Okinawa was not considered in this study.

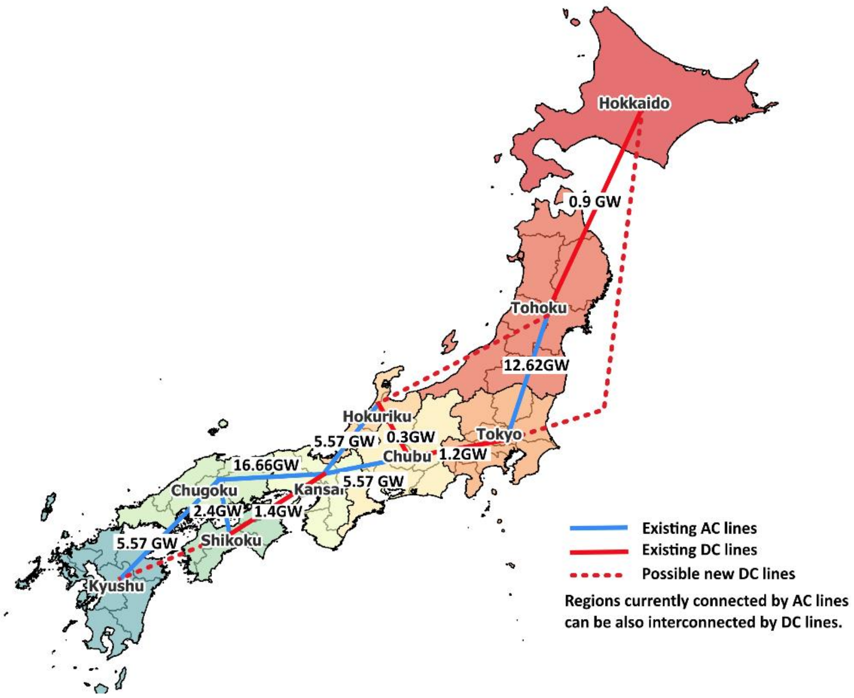


Figure 2.2: Regional structure based on the nine EPCO areas, existing physical and possible future grid interconnections.

The nine regions are interconnected with a power transmission network. The structure and the capacity of interconnections are based on the existing grid structure[7] updated according to the latest information by EPCOs). The model considers the possibility to build additional grid interconnections, like a direct sea cable connection between Hokkaido and Tokyo region, or DC connection from Tohoku to Hokuriku. Connection costs are considered in the model based on the connection cost per GW*km, line capacity and the distance between consumption centers of the nodes (biggest agglomeration in the region). For HVDC lines the costs of the AC-DC converters are also included. It does not take into account the grids within the regions. For 2020, the current grid utilization limits are applied according to the status quo (latest net transfer capacity (NTC) values range from about 25 to 50% of the total physical capacities for AC lines while DC lines can be used up to 100%), while for later periods, the grid utilization limitations are considered to be relaxed so the transmission power lines' average utilization is limited to 80% on average.

2.3. Data preparation

The main assumptions for the transition scenarios can be divided into three categories:

- Energy and services demand for each sector;
- Renewable resources;
- Financial assumptions.

Demand assumptions for the energy sectors

The estimation of the evolution of energy demand was carried out separately for power and heat on one hand, deriving from energy demand in the residential, commercial and industrial sectors, and for the transport sector on the other hand (see Figure 2.3). Overall final energy demand was assumed to decline by about 35% with the combined effect of different trends.

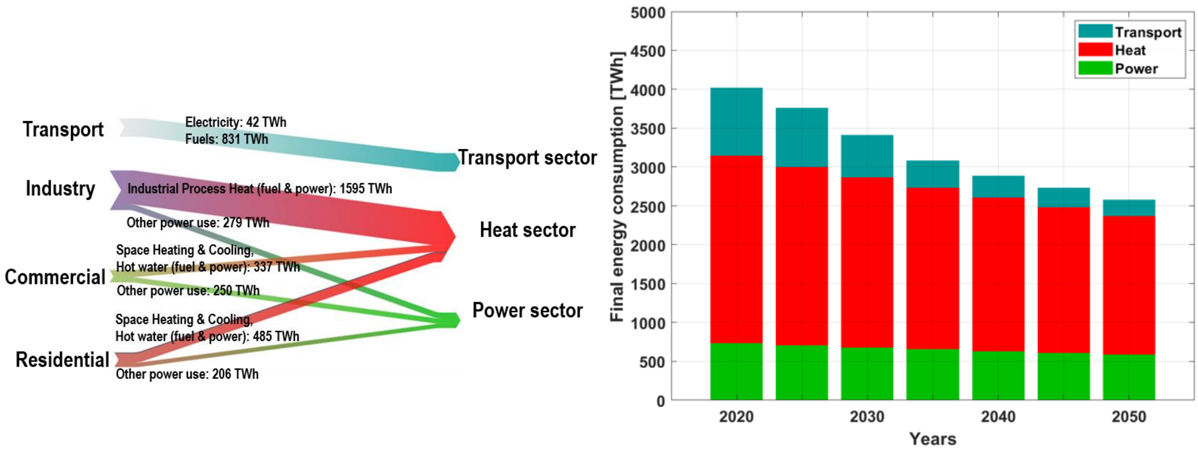


Figure 2.3: Demand structure for 2020 and evolution of final energy consumption per sector until 2050.

Demand assumptions for the power and heat were set in two steps. First, demand for the year 2020 was calculated from past available data. The data until FY2017 was available from statistics of the Ministry of Economy, Trade and Industry (METI) [8], as of February 2020, were used as a base and extrapolated until 2020. Data at prefectural level was summed up according to the EPCO area borders, with an exception for Shizuoka, for which the demand was divided between Tokyo and Chubu EPCO areas. The numbers were reprocessed to estimate the final power and heat consumption in three categories: final electricity consumption of residential, commercial and industrial sectors, final heat consumption for those same sectors, and electricity consumption for cooling, which was integrated into the heat sector.

As a second step, the evolution of the demand until 2050 was estimated and applied to the 2020 numbers. Final energy consumption was assumed to continuously decrease due to population decrease [9], corresponding to a 20% decline in final electricity consumption in the residential, commercial and industrial sectors by 2050.[22] Demand in the residential and commercial sectors was

[22] The final energy consumption here does not include energy efficiency improvements in the building sector, as it includes ambient heat for lower temperature heat supplied by heat pumps.

assumed to decline by 20%, and by 30% in the industrial sector. Efficiency improvements in the building sector are assumed to be compensated by rebound effect and the increase in living space and energy consumption per capita. In 2020, almost all the residential and commercial heat demand is covered by individual heat systems in Japan. By 2050, we assumed a gradual but limited introduction of district heat supply to 5% of the residential and commercial heat demand.

Energy demand for transport was calculated combining three elements: transportation service demand per segment, the share of fuel type for each segment, and average fuel consumption per segment and fuel type. Energy consumption in transport was considered to reduce more significantly than in the heat and power sectors due to efficiency improvements of ICE engines and especially the electrification of the road transport segment.

Transportation service demand was estimated for the following segments: road, rail, maritime transport, and aviation, both in passenger kilometers (p-km) for passenger transport and in (metric) tonne kilometers (t-km) for freight transport. In the model, the road segment is additionally subdivided into passenger light-duty vehicles (LDV), passenger 2/3-wheelers (2W/3W), passenger bus, freight medium-duty vehicles (MDV), and freight heavy-duty vehicles (HDV), for which separate assumptions were made. These numbers were based on population decline for the base scenario, and the METI projection of transportation volumes for 2030 for the delayed policy scenario [10] that were extrapolated until 2050. As this data is available at a national level only, regional demand for road and rail transport was estimated based on the regional share of population. For aviation and maritime transport, the regional split was made based on regional airport and seaport passenger and freight throughputs.

The shares of each vehicle type (internal combustion engine (ICE), plug-in hybrid (PHEV), electric (EV) and fuel cell electric vehicles (FCEV)) in the newly bought vehicles for each step of the transition were estimated based on the usage cost of the different vehicle types as described in Khalili et al. [11] and METI 2030 projections [10]. The specific energy consumption by transport means are based on METI material [4] and future estimation of efficiency improvements are based on Khalili et al. [11]. Detailed information on demand is presented in the Appendix (tables A5 to A23).

Renewable energy resources

For each of the nine regions considered in this study and each renewable technology, a capacity limit was set (see Table 2.4). The capacity was defined according to population density, the landscape, land use and building location determining the area available for wind turbines and PV installations and consistency was ensured with studies published by RTS and the Ministry of Environment. For hydropower, no significant possible addition to existing capacity was assumed due to negative impacts on the river ecosystems.

Table 2.4: Maximum capacity for RE technologies by 2050 set in the study.

	PV *[GW]*	Wind onshore *[GW]*	Wind offshore *[GW]*	Hydro RoR *[GW]*	Hydro Dam *[GW]*
Japan total	524	147	418	5.3	16.9
Hokkaido	20	84.25	223.3	0.5	0.75
Tohoku	49.1	25.9	76.9	0.7	3.8
Tokyo	163.7	6.5	55.3	0.9	2.1
Hokuriku	5.2	5.85	23.6	0.9	1.6
Chubu	87.8	2.5	0.5	1	2.5
Kansai	84.7	6.6	3.8	0.5	3.1
Chugoku	38	6.6	1.1	0.3	0.7
Shikoku	18.1	2.7	12.4	0.1	0.8
Kyushu	57	6.5	21.3	0.4	1.5

In addition, the maximum capacity that can be installed was limited to 145 GW for PV, and 18 GW and 10 GW respectively for onshore and offshore wind turbines until 2030.

The capacity factor profiles for optimally fixed tilted PV, onshore and offshore wind generation are calculated according to Bogdanov and Breyer [12] using global weather data for the year 2005 from NASA [13,14] and reproduced by the German Aerospace Centre [15]. The hydropower feed-in profiles are computed based on the monthly river flow data for the year 2005 [16], as a normalized weighed average flow in locations of existing hydropower plants. The maximum available biomass and waste resources are classified into four main categories: forest industry wastes, solid wastes, solid residues and biogas. The assumptions on available resources are based on data from the Food and Agriculture Organization of the United Nations [17] for agriculture and forestry residues and from the World Bank [18] for waste. The cost of biomass is based on METI data [19]. Detailed information on regional RE capacity factors as well as biomass fuels availability data in regional resolution are presented in detail in the Appendix (table A24).

Financial assumptions

The cost of technologies was determined in two steps. For current costs, the available data on existing cost of technologies in Japan as of 2019 were used. A future cost evolution trajectory was then determined for each technology, based on a range of projections made by RTS, METI, IEA-and REI. For new technologies which are not yet available in Japan (for example Power-to-X (PtX) technologies), global market assumptions for 2020 were used, to which a 100% cost top-up was added for the Japanese market, as it is currently the case for a wide range of technologies. The cost of RE-based generation, energy storage, PtX and transmission technologies was assumed to decline through the transition, as well as the Japanese cost top-up if applicable. The cost of onshore and offshore wind, batteries, and PtX technologies were assumed to converge with global market levels by 2050. An exception was made for solar PV, for which the cost was assumed to decrease from about 145 ¥/Wp (1.3 $/Wp) in 2020 to 44 ¥/Wp (0.4 $/Wp) in 2050, where the 2050 cost would still be 100% higher than in global markets. The cost of conventional generation technologies was set with a gradual decline until 2050, except for nuclear energy, for which the cost was assumed to remain at a constant level throughout the transition.

The cost of capital is set to 7% for the entire transition and investments in all technologies. A detailed description of the financial and technical assumptions, including capital and operational costs, lifetime and efficiency for all technologies, costs of fuels as well as retail electricity prices and their sources are presented in the Appendix, tables A1 to A3.

2.4. Scenarios

Six decarbonization scenarios for Japan based on renewables were modeled in this study around a central and ambitious scenario, the Base Policy Scenario (BPS). This scenario assumes favorable policies for a massive and early introduction of renewables in all sectors and electrification of demand, combined with a fast increase in carbon pricing and coal and nuclear phase-out in power generation, leading to a fast decline in greenhouse gas (GHG) emissions. In order to display the possible impact and benefits of sustainable energy imports from abroad, BPS was modeled in three scenarios: one with only Fischer-Tropsch (FT) fuels[23] that can be imported, another with FT fuels and electricity imports from Russia or Korea/China, and the last which can import electricity and all kinds of e-fuels (including FT).

Table 2.5: Scenarios modelled in the study.

<table>
<tr><td colspan="2"></td><td colspan="4">Energy import</td></tr>
<tr><td colspan="2"></td><td colspan="2">Autarky scenario (Fischer-Tropsch fuels can be imported)</td><td>Electric interconnexion with neighbors (FT fuels + power)</td><td>Import scenario (power + all e-fuels incl. FT fuels)</td></tr>
<tr><td rowspan="3">Demand</td><td>Reference</td><td>DPS</td><td>BPS (Autarky)</td><td>BPS power import</td><td>BPS all import</td></tr>
<tr><td>-10%</td><td></td><td>BPS Low10</td><td></td><td></td></tr>
<tr><td>-20%</td><td></td><td>BPS Low20</td><td></td><td></td></tr>
<tr><td colspan="2"></td><td>Lower</td><td>Higher</td><td></td><td></td></tr>
<tr><td colspan="2"></td><td colspan="2">Speed of transition</td><td></td><td></td></tr>
</table>

The impact of delayed policies is studied with a sensitivity scenario referred to as Delayed Policy Scenario (DPS), characterized by a slower introduction of RE during the initial years of the transition and sustained investments in the existing fossil generation capacities. The impact of lower future final energy demand due to population decline and efficiency improvements, notably in industrial processes, new insulation options in buildings or smart technologies are reflected in the demand sensitivity scenarios.

[23] The Fischer-Tropsch process is a collection of chemical reactions for liquid hydrocarbons synthesis from hydrogen and carbon monoxide. Synthetic liquid hydrocarbons can be further refined and used as fuels, typically in aviation and maritime transport, or as a raw material in the chemical industry. Among synthetic fuels (e-fuels), FT fuels are the costliest to produce, followed by synthetic methane and hydrogen.

Assumptions of the Base Policy Scenario

This scenario aims to reach both governmental and 1.5°C targets for 2030, and zero GHG emissions from the energy sector by 2050. To reach this goal, at least 35 GW of solar PV are installed in the years 2020-2025 and the share of RE in electricity generation reach at least 40% by 2030. At the same time, coal and nuclear power plants (respectively 41 GW and 9 GW in 2020) are totally phased-out by 2030, no additional nuclear reactors are restarted, and no new coal, oil or nuclear power plants are commissioned. Coal can still be used in industrial heat and processes until fossil fuels are fully banned in 2050. The commissioning of new gas-fired power plants is allowed, however these power plants would switch to use sustainable synthetic and bio-methane in the later steps of the transition.

A quick electrification of the transport and heat sectors is expected, especially in space and water heating in the residential and commercial sectors, as well as in road transport where internal combustion engine (ICE) vehicles would be replaced by electric vehicles. The following assumptions for road transport are taken for this scenario:

- By 2050, the share of battery-electric vehicles (BEV) in passenger transport is assumed to exceed 76%, while the share of ICE and plug-in hybrid electric vehicles (PHEV) drops to about 13%.
- In freight transport, the share of BEV in 2050 is assumed to reach 67%, while ICE and PHEV still play a significant role with 26% of all freight transport. Fuel cell electric vehicles (FCEV) powered with hydrogen are assumed to represent around 10% of passenger and 6% in freight segments of road transport in 2050.
- Rail transport is assumed to be fully electrified by 2050, while maritime transport and aviation are considered not to be electrified at all.

The existing carbon pricing was set to rise from 290 ¥/ton (2.64 $/ton) today to 5 500 ¥/ton (50 $/ton) in 2030 and to 18 000 ¥/ton (164 $/ton) in 2050 (see appendix, Table A3). For 2040 and 2045, a minimum share of sustainable e-fuels was also set to be used in the transport and industry sectors in order to enable a gradual introduction of decarbonized fuels in the system, in preparation of a fossil fuel ban in 2050. In the transport sector, 43% of liquid fuels used in maritime transport, aviation and road transport should be from sustainable sources in 2040 and at least 76% in 2045. The required sustainable liquid e-fuels will be imported, as it is the case for oil today. In the industrial sector, 15% of fuels used in processes must be H_2 or synthetic methane by 2040, increasing to 50% by 2050.

Last but not least, prosumers are assumed to play an important role in power supply, so that prosumers self-supply can increase to a maximum of 20% of all power sector demand.

Import sensitivity scenarios

To investigate the impact of sustainable energy imports on the energy system, two additional sensitivity scenarios were tested based on the BPS scenario. In a first scenario, renewable electricity imports from Russia and China/Korea are enabled after 2030, all other assumptions being same. In a second scenario, power import as well as import of green e-fuels from Australia is possible after 2030. In both scenarios, electricity import entry points are Ishikari, Hokkaido for imports from Russia, and

Matsue, Chugoku for imports from China via Korea. In 2035, 2 GW of grid interconnections are available for each route, increasing to 10 GW each in 2045-2050, with a maximum capacity factor of 80%, amounting to maximum power imports of 28 TWh_{el} per year starting in 2035 and 140 TWh_{el} per year between 2045 and 2050. In order to reflect the cost decline of RE generation, storage and transmission technologies during the expansion of the import capacity, a gradual decline in imported electricity costs is assumed (see Table 2.6, see in appendix, table A4 for more detailed information). The imported electricity cost includes generation, storage and transmission costs to Japan. The cost of RE resources in Russia's Far East and Northeast China are in line with global assumptions.

Table 2.6: Electricity import connection capacity and imported electricity prices.

		2035	2040	2045	2050
Grid connection capacity: China/Korea	*[GW]*	2	6	10	10
Estimated import cost at Matsue	*[¥/MWh]*	6 936	6 852	6 516	6 324
	[$/MWh]	63.1	62.3	59.2	57.5
Grid connection capacity: Russia	*[GW]*	2	6	10	10
Estimated import cost at Ishikari	*[¥/MWh]*	6 432	6 336	5 952	5 856
	[$/MWh]	58.5	57.6	54.1	53.2

In the second sensitivity with both electricity and e-fuel imports, additional imports of RE-based e-fuels, liquified natural gas (LNG) and hydrogen, are allowed from 2035 onwards. The imported e-fuels volume was however limited to 50% of total consumption, so that the rest has to be covered by local synthesis units. The cost of imported fuels was estimated based on the cost of RE resources in West Australia and assumed shipping costs, reflecting the expected cost decline of RE generation, storage and e-fuels synthesis technologies during the period (see Table 2.7; see in appendix, table A4 for more detailed information).

Table 2.7: E-fuels import prices.

		2035	2040	2045	2050
Green liquid hydrogen	*[¥/MWh]*	9 935	8 964	8 964	6 891
	[$/MWh]	90.3	81.5	81.5	62.6
Green synthetic methane	*[¥/MWh]*	13 632	12 217	12 217	9 381
	[$/MWh]	123.9	111.1	111.1	85.3

Delayed Policy Scenario

This scenario represents the case of a delayed transition in all the energy sectors, though aiming to fulfil governmental targets by 2030 and reach zero carbon emissions in 2050. PV capacity is expected to increase by 20 GW during the years 2020-2025, 15 GW less than in the BPS, and the share of RE in power generation in 2030 is set to reach 30% (10% lower than in the BPS). The total installed capacities will be increasing at a slower pace, with a delay of about 5 to 10 years compared to the assumption in the BPS. As such, the cost of PV and wind turbine technologies will be decreasing with a 5-year delay compared to the reference values assumed for the BPS.

Table 2.8: Comparison of the main assumptions in BPS and DPS.

Base Policy Scenario		Delayed Policy Scenario
Fast decarbonisation ahead of government plan until 2030, carbon neutral in 2050	Carbon targets	Delayed decarbonisation following government plan until 2030, carbon neutral in 2050
No new nuclear, no restarts, only currently operating plants stay Nuclear generation stops in 2030	Nuclear	2 new nuclear power plants under construction to be commissioned Nuclear PPs operate until end of lifetime, no further lifetime extensions permitted
Coal power generation banned in 2030 Coal use in heat optimised by the model and banned in 2050	Coal	Coal in power generation allowed till 2050 Coal in heat optimised by the model and banned in 2050
Cost decline following learning curve	RE cost	5-year delay in PV and wind cost decline
40% of RE in power generation in 2030 Generation mix fully optimised by the model based on financial and technical parameters	Generation mix	30% of RE in power generation in 2030 Coal and gas power generation supported after 2030 to limit stranded investments
Fast direct and indirect electrification	Heat	Delayed direct and indirect electrification
Fast electrification	Transport	Delayed electrification

Contrary to the BPS, some new coal and nuclear power plants under construction will be commissioned in addition to currently operating capacities: units 1 and 2 of the Yokosuka coal power plant in 2025, with a total capacity of 1.3 GW, as well as two nuclear power generation units by 2035, the 1.38 GW unit of Ohma power plant in Aomori prefecture and the 1.37 GW unit 3 of Shimane nuclear power plant. No additional lifetime extension of nuclear power plants is permitted beyond those already planned by end of 2019. New gas-fired power plants can also be commissioned; however, these power plants would switch to sustainable synthetic and bio-methane during the later periods of the transition. Overall, conventional power plants can operate until the end of their technical lifetime, the only limit being the fossil fuel ban in 2050.

In this scenario, coal generation is considered to be politically supported in the 2030s and 2040s in order to avoid stranded assets, with a minimum guaranteed capacity factor (CF) of 80% before 2040, 50% in 2040 and 30% in 2045. Similarly, gas generation also receives some support with a minimum

CF of 80% for combined cycle gas turbines (CCGT) before 2040, 70% in 2040 and 60% for 2045, and 12% for open cycle gas turbines (OCGT) before 2040, 6% in 2040 and 3% in 2045.

In the transport and heat sectors, the DPS assumes slow electrification of space and water heating in residential and commercial sectors, as well as road transport. By 2050, the share of BEV in passenger transport will increase to around 70%, while the share of ICE and PHEV will drop to about 20% and 10% respectively. In freight transport, the share of BEV in 2050 will increase to around 54%, while ICE and PHEV shares will be 20% and 10% of all freight transport. The share of hydrogen powered FCEV in 2050 road transport mix is assumed to be around 0.01% in the passenger and 16% in the freight segment. As in the BPS, rail transport is assumed to be fully electrified, while maritime transport and aviation are not electrified.

Carbon pricing increases, but half as much as in the BPS: from 290 ¥/ton (2.64 $/ton) in 2020 to 2 750 ¥/ton (25 $/ton) in 2030, and to 9 000 ¥/ton (82 $/ton) in 2050 (see appendix, Table A3). The minimum share of sustainable e-fuels in transport and industry are set at the same level as in the BPS, as well as the maximum share of PV prosumers self-supply.

Demand sensitivity scenarios: 10% lower and 20% lower demand scenarios

A decrease of about 35% of final energy consumption by 2050 was assumed in the reference demand level used in all the scenarios above. However, the impact of population decline and efficiency improvements on the level of energy consumption can be higher. To quantify the effect of a faster and steeper final energy consumption decrease on the energy system transition, additional Base Policy Scenario variants of the BPS autarky scenario were modelled with 10% (Low10), and 20% (Low20) lower final consumption in 2050, all other things being equal. As such, final energy consumption was assumed to decrease linearly between 2020 and 2050, the starting level in 2020 being the same in all scenarios.

3. Base Policy Scenario - Autarky

In this scenario, the Japanese energy system is set on an ambitious pathway: the introduction of renewables is supported starting from the 2020s so that the share of renewables in electricity generation will reach 40% by 2030; carbon pricing is expected to significantly rise to levels applied or planned in Europe; a ban on coal-based electricity generation from 2030 onwards leads to an accelerated substitution with low- or zero-emission technologies. Almost all the energy is produced domestically based on renewables by 2050, except for Fischer-Tropsch fuels used in the transport sector that can be imported. This pathway results in a sharp drop in fossil fuels imports and consequent GHG emissions, leading to a fast transition towards a sustainable self-sufficient energy system.

3.1. General outlook

The scenario shows a rapid decline in GHG emissions, especially after 2025, reaching zero emissions in 2050 in the energy-related sectors as modelled in this study (Figure 3.1).[24] By 2030, energy related GHG emissions decrease by 39% against 2020 levels in those sectors, corresponding to a reduction of 49% against 2013 levels, largely fulfilling the NDC target for 2030, and a reduction by 45% relative to 2010 levels, exactly in line with a 1.5°C scenario target for those sectors.[25]

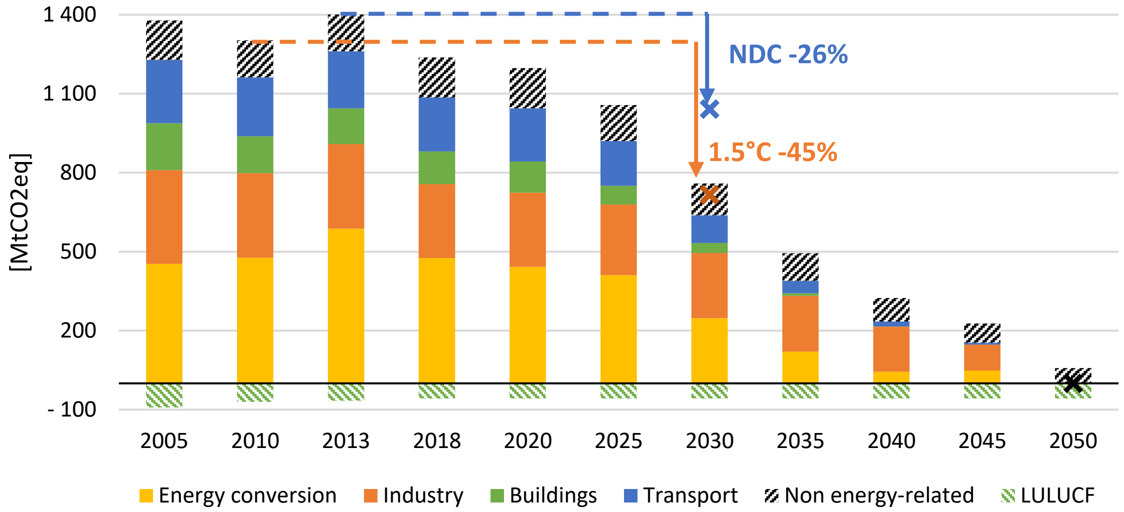


Figure 3.1: BPS (Autarky) – evolution of energy-related GHG emissions per sector and current climate targets.

The building sector would be the first sector to decarbonize, its emissions decreasing by 68% between 2020 and 2030, and the sector fully decarbonized by 2040. The transport sector undergoes a rapid

[24] The GHG emissions until 2018 are historical data from the National Greenhouse Gas Inventory Report of Japan 2020 published in the UNFCCC format. The 2018 values for non-energy related emissions and carbon sinks through LULUCF are prolonged as a reference for the year 2020 and are shown to decline linearly after that to reach the level of the carbon sinks so that Japan reaches net zero emissions in all sectors by 2050.

[25] The non-energy related emissions are not considered in this study and should decrease at least to the level of availability of carbon sinks (LULUCF) for the overall emissions to reach the 1.5°C target.

decarbonization with its emissions halved between 2020 and 2030 and achieving an emissions reduction of 97% by 2045. The energy conversion sector, an important sector considering the increasing electrification of energy uses, will also reach -44% of emissions by 2030 and -90% by 2040. The emissions in the industry sector decline more slowly than in the other sectors, as medium and high temperature heat can only be defossilized in the later stages of the transition. The emissions decline only by 12% between 2020 and 2030, and by 65% until 2045, the remaining emissions drastically eliminated in the last years of the transition. The cumulative GHG emissions from 2020 to 2050 reach around 14.3 $GtCO_{2eq}$.

The BPS scenario foresees a transition from fossil fuels to renewable energy technologies in all energy uses combined with a quick electrification and a decrease of about 35% in final energy demand. The FED decline is driven by the projected population decline and consequent 20% decline of the power, heat and transport sector services, and the estimated efficiency improvements on the demand side. Consequently, the population decline and the efficiency improvements on the demand side (mostly due to the electrification of the transport sector and increased motor efficiency) lead to a 35% decline in primary energy demand (PED), and efficiency improvements on the supply side (mainly due to renewable-based electrification of low and mid temperature heat (heat pumps)) to a further decline by 15%. This translates into a 50% drop in PED from about 4 600 TWh in 2020 to about 2 360 TWh by 2050 (see Figure 3.2). Without taking into account renewables-based electrification, PED would only decrease to about 3 700 TWh by 2050 (Figure 3.2 right), showing the effectiveness of electrification and defossilization in a decarbonization strategy.

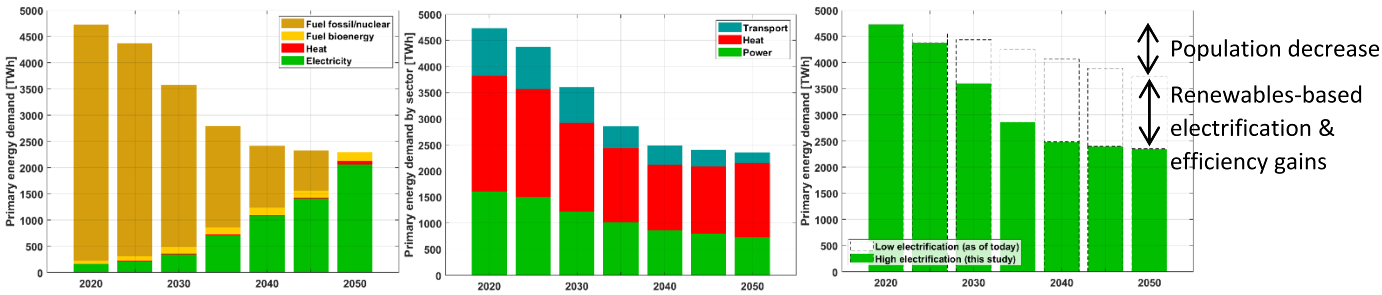


Figure 3.2: BPS (Autarky) – evolution of primary energy demand per energy carrier (left), per sector (middle), and effect of electrification and efficiency gains in primary energy demand (right) from 2020 to 2050.

This scenario foresees the replacement of imported fossil fuels by domestically produced renewable electricity, partly transformed into synthetic fuels to meet specific needs. Only Fischer-Tropsch (FT) fuels used in aviation and maritime transport were set to be possibly imported, as their production is likely to stay costly during the whole transition until 2050. About 700 TWh of FT fuels are imported according to this scenario between 2035 and 2050, settling at about 70 TWh in 2050, representing about 3% of total primary energy demand. Energy dependency would as such decline drastically by 2050 to achieve almost autarky, down from 88% in 2018 [2].

The following sections will analyze the energy transition pathway for each sector, at national and regional levels.

3.2. Energy supply and storage

Power

The electrification of the energy system leads to a substantial increase in power demand and installed generation capacities (see Figure 3.3). Power generation is multiplied by 2.2, while total installed capacity almost quadruples from around 240 GW in 2020 to about 968 GW in 2050, of which 90% would be wind and solar power, up from 27% in 2020. In 2050, power generation is covered to 100% by RE, up from 18% in 2020. The electrification-based decarbonization follows a 3 stage-process:

- 2020-2030: slight increase in energy generation (+0.4% on average per year), as new uses are starting to electrify, and renewables pursue their expansion
- 2030-2045: gradual increase in energy generation (+3.1% on average per year), as electrification is generalized in the transport and heating sectors
- 2045-2050: (+6.3% on average p.a.): sharp acceleration of electricity generation, as to provide synthetic fuels for the hard to electrify and hard to abate industry sectors. In case Japan relies more on imports of synthetic fuels (see section 4), this final increase in renewable based power generation (mostly onshore and offshore wind) is much less pronounced.

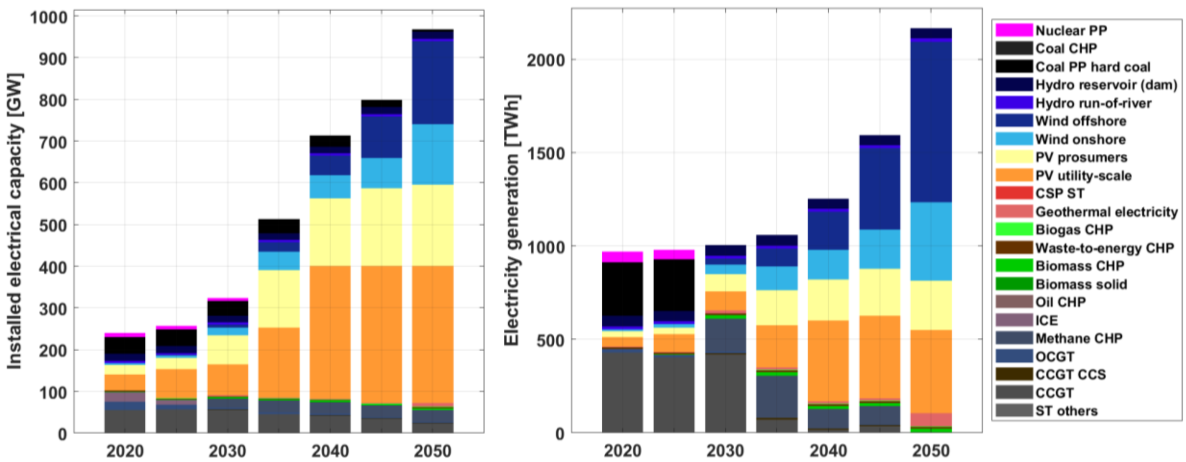


Figure 3.3: BPS (Autarky) – evolution of installed capacity (left) and power generation (right) from 2020 to 2050.

As coal and nuclear power generation is banned in 2030, 22 GW of gas CHP plants are being built and these fill about half of the supply gap, the rest being covered by newly installed solar PV and onshore wind capacities (144 GW solar PV and 25 GW wind installed capacities by 2030).[26] From 2035 onwards, mostly solar PV and wind energy are being installed. Solar PV is being built first as the least-cost energy source, reaching 524 GW in 2050, the maximum capacity that can be installed as set in this study. Wind energy is being built quicker after 2040, after most of the solar PV resources have been exhausted. Onshore wind is installed up to its maximum capacity that can be installed as set in this study (144 GW), similarly to solar PV. Offshore wind is the last technology to be installed due to its

[26] Carbon Capture and Storage (CCS) is a very costly technology with currently a lot of uncertainties in terms of cost and large-scale deployment. It is also unclear if reliable long-term CO_2 sinks can be created for carbon sequestration and how much captured CO_2 Japan would be able to store under its soil. Due to the high expected costs, carbon sequestration was limited in the scenarios.

comparatively higher cost but will reach 199 GW. This amounts to an annual installed capacity of 8.4 GW of solar PV, 1.5 GW of onshore wind, and 0.7 GW of offshore wind between 2021 and 2030, and of 20.1 GW of solar PV, 6.5 GW of onshore wind, and 9.6 GW of offshore wind between 2031 and 2050. Offshore wind will provide up to 40% of total electricity generation in 2050 (858 TWh).[27] Solar PV will contribute with 708 TWh (33%) and onshore wind with 422 TWh (19%).

The land issues related to renewable capacity installations and their respective need for space are often raised as a concern in Japan. According to the scenario, utility-scale solar PV (328 GW) uses 1.3% of land area by 2050, while onshore wind takes up to 3.8 %. This shows rather limited land area is needed to install this large amount of renewable capacity in Japan.

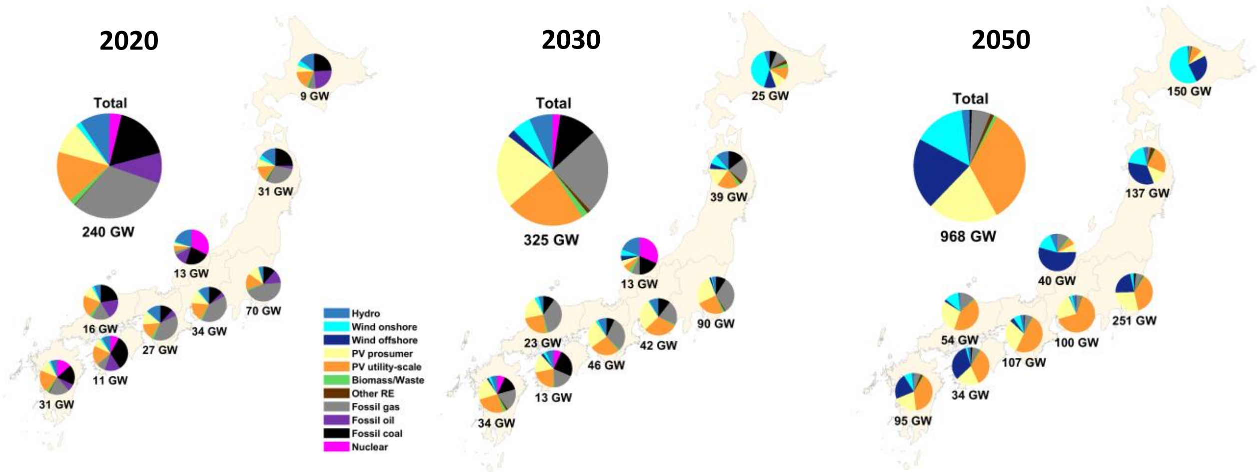


Figure 3.4: BPS (Autarky) – regional electricity generation capacities in 2020 (left), 2030 (center), and 2050 (right).

The modeling results additionally show that renewable capacities are distributed unevenly across the country (Figure 3.4). Solar PV capacities are spread across the country, representing most of the installed capacities in the western and central regions. The vast majority (76%) of onshore wind capacity is built in Hokkaido and Tohoku, the 2 northern regions with comparably low population density and high wind potential, while offshore wind mostly in the half Eastern side of Japan (in decreasing order Tokyo, Tohoku, Hokkaido and Hokuriku) but also in Kyushu as all the other regions have reached the upper capacity limit for all technologies. Though solar PV represents most of the installed capacity in 2050, wind generates more than 50% of the total electricity supply in most of the regions and country wide.

Prosumers[28] play an important role in the transition. Due to relatively high retail electricity prices, prosumer PV is highly competitive, leading to a quick capacity growth in the 2020s. From 23 GW in 2020, it more than doubles in 10 years and reaches 70 GW by 2030, representing half of the total installed PV capacity. By 2050, prosumer capacity reaches 196 GW – 37% of total PV capacity. Prosumer PV generates around 12% of all electricity supplied in 2050, though the role of PV prosumers

[27] Offshore wind offers a big opportunity in Japan due to long coastlines. The maximum capacity that can be installed was set at 418 GW for this study. More capacity could be built if costs were to decrease further than expected in the framework of this study.
[28] In this study, prosumers are individual residential, commercial and industrial entities installing solar PV systems on their rooftop, with or without lithium-ion batteries. See section 2.1 for more details.

in electricity generation depends on the region. It is lowest in the northern regions of Hokkaido and Tohoku due to higher LCOE of solar PV in these regions and the abundance of wind resources, and highest in the densely populated central regions such as Tokyo, Chubu, Kansai, and Chugoku.

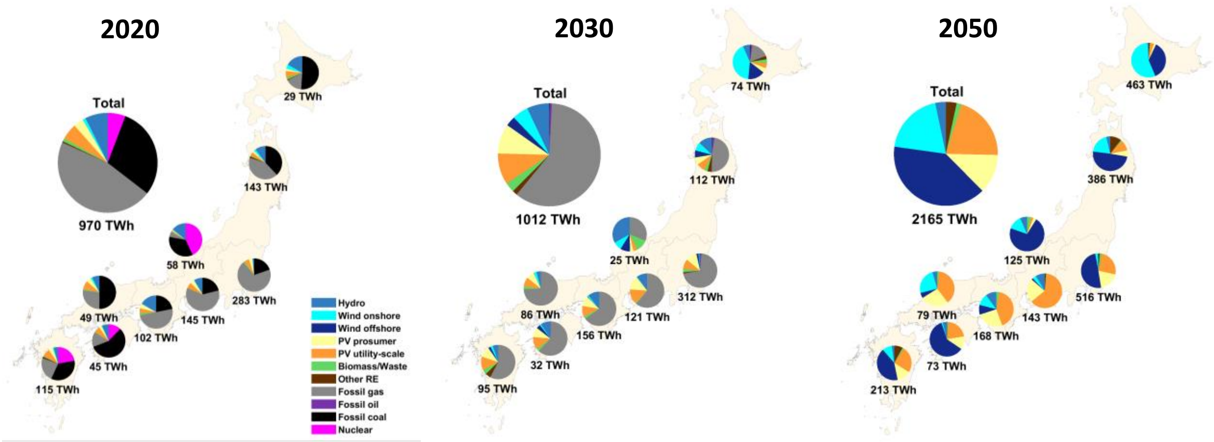


Figure 3.5: BPS (Autarky) – regional electricity generation in 2020 (left), 2030 (center), and 2050 (right).

Interregional power trade thus becomes important compared to today, providing additional flexibility to the system: about 38% (829 TWh) of the generated electricity is traded between the regions in 2050, up from 133 TWh in 2020 (Figure 3.6). Hokkaido exports about 70% of its total generation (321 TWh) as the leading net exporting region, followed by Tohoku with 182 TWh (47% of its generation) and Hokuriku with 80 TWh (65% of its generation). Tokyo imports most with 204 TWh of net import (29% of its demand), followed by Chugoku with 151 TWh (66% of its demand), Kansai with 129 TWh (44% of its demand), and Chubu with 77 TWh (34% of its demand).

Interregional transmission grids are being built accordingly. Most of the grid capacities are built to connect the windy regions in the east with the central and western regions. The model builds 60 GW of direct interconnection between Hokkaido and Tokyo, enabling the direct flow of electricity from wind farms in Hokkaido to satisfy the energy demand in the densely populated region of Tokyo. Additionally, a new interconnection is built between Tohoku and Hokuriku (+21 GW), the Tokyo-Chubu interconnection is reinforced (+20 GW) and the interconnections between the currently mostly self-sufficient 50Hz and 60Hz zones is increased by 40 GW. The reinforcement of the connections Hokuriku-Knsai, Chubu-Kansai, Kansai-Chugoku, Chugoku-Kyushu enables the transfer of wind energy from east to west.[29]

[29] Until 2030 the grids are used according to existing NTC limits, but afterwards the NTC limits are considered to be relaxed to optimize the use of the interconnections. The grid utilization capacity factor (CF) stays limited to 80% after 2030. The CF of most of the AC lines remain below 50%. Only in 2050, the CF for the lines Hokuriku-Kansai, Chubu-Kansai, and Kansai-Chugoku reach 80% to enable baseload electricity transfer to the Western regions of the country.

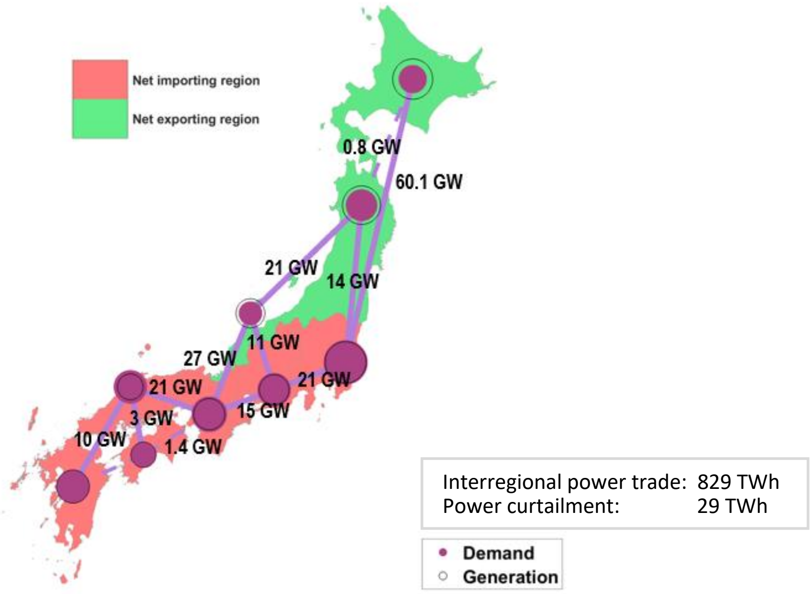


Figure 3.6: BPS (Autarky) – installed grid capacities and interregional power trade in 2050.

The net exporting regions have excellent wind resources which become the main source of exported electricity. Indeed, the grid and gas storage utilization profiles also show a strong correlation with wind generation profiles. The grid is mostly used during the winter (Figure 3.7, left), while gas storage is also being charged.

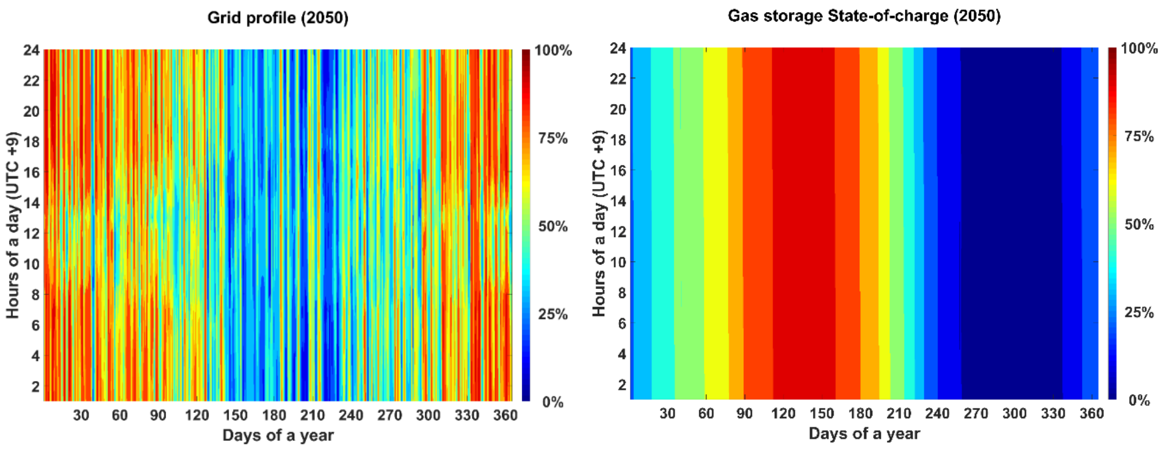


Figure 3.7: BPS (Autarky) – power grid utilization profile (left) and utilization of gas storage (right) in 2050.

In the summer, when wind generation is limited, regional energy systems become more self-sufficient, relying mostly on local PV generation and gas storage discharging (Figure 3.7, right). Synthetic methane stored during the winter allows the industry to operate during low wind periods, while e-fuels production for industry decreases significantly. In the scenario where a large share of synthetic fuels (hydrogen, synthetic methane and FT fuels) is imported, the need for infrastructure (grids, storage) declines significantly.

Figure 3.8 illustrates how typical weeks in the summer and the winter look like in 2050. The overall system capacity exceeds 1000 GW (including VRE and flexible generation) and flexible demands adjust to the generation profile of variable renewables. Overall, the balancing of the energy system based on variable renewable energy is done by three main flexibility sources. First, power grids allow to transfer electricity from areas with energy excess to areas with energy deficit, especially in the winter when there is a lot of wind power in the Eastern regions. Then, electricity storage including batteries, pumped hydro energy storage (PHES), smart charging and vehicle-to-grid (V2G) technologies balances temporal fluctuations of demand and renewable generation. Finally, power-to-heat and power-to-fuels coupled with heat and fuel storage offer long-term demand-side flexibility as seasonal storage. The flexible generation from hydro power also plays a role, but with a limited impact.

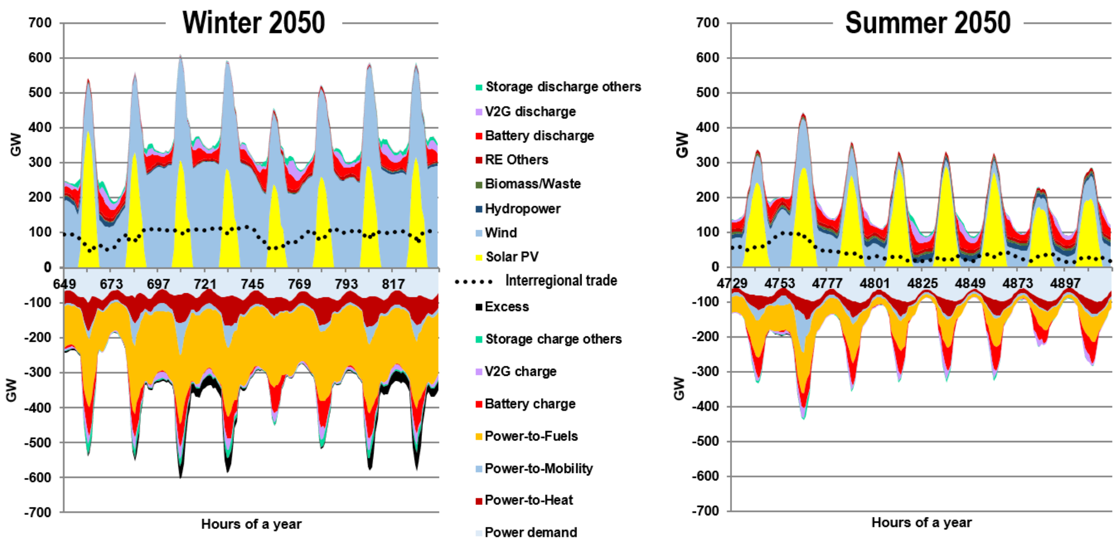


Figure 3.8: BPS (Autarky) – supply-demand balance during a typical week in the winter (left) and in the summer (right) in 2050.

Peak load (including power demand for general application, electricity for heating, cooling, e-fuels synthesis, electrical mobility, storages charge) can exceed 550 GW in winter at midday when solar PV and wind feeds-in are high (Figure 3.8, left). Flexible demand (storage, V2G charging, power-to-mobility, power-to-heat, power-to-fuels) is activated during those hours, pushing up the maximal load and resulting in a rather low curtailment level of renewables (less than 1.7% of total power generation). Since there is massive flexible demand, the peak load is much lower during hours of low renewables feed-in. It reaches only about 87 GW during those periods that occur mostly in summer at nighttime (Figure 3.8, right). This load then represents the inflexible demand (in particular power for general applications, dumb charge in transport and partially power-to-heat, as some part cannot be buffered through heat storage). The Japanese system has enough flexible energy sources available to meet this inflexible demand in 2050 with 17 GW of hydro dams, 30 GW of pumped-hydro storage, 53 GW of gas turbines and gas CHP running on biogas and e-fuels, 9 GW of biomass power plants and CHP and 98 GW of battery storage. Plus at least 11 GW of wind capacity that are generating during every hour in 2050.

The operation of an energy system based on RE can be highly efficient. In a RE based energy system with a share of variable renewables of about 85% of TPES, curtailment can be limited to about 1.7%

of total power generation (Figure 3.8). Curtailment occurs in the periods of energy surplus, usually when wind generation is high, all the generated energy is used in the summer months with lower generation.

Heat

Heat is primarily used for industrial processes, domestic hot water, and space heating in the residential and commercial sectors. Heat generation is currently mostly based on fossil fuels across all sectors, but they are substituted gradually over the transition by RE-based electric heating and wherever direct electrification is not possible, by e-fuels (green hydrogen and synthetic methane). By 2050, all the heat demand is directly or indirectly electrified, making it the main electricity consumer - 59% of all electricity generation is required for electric heating and e-fuels production for industrial heat processes.

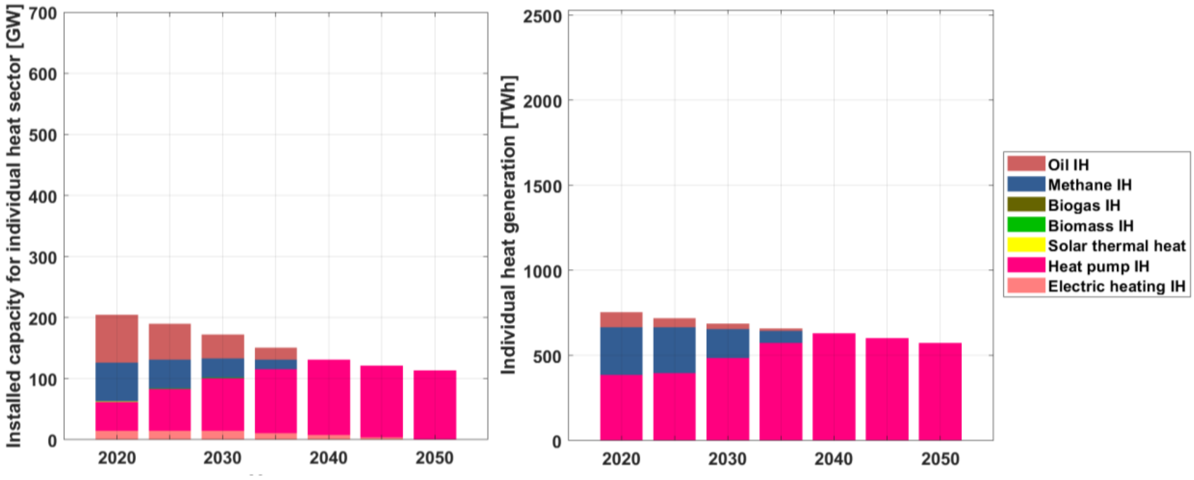


Figure 3.9: BPS (Autarky) – evolution of heat generation capacity (left) and heat generation (right) in the buildings sector from 2020 to 2050.

The decrease in heat demand in industry, space and water heating leads to a significant reduction of heat generation capacity. The deployment of heat storage technologies allows to further decrease the heat capacity needed to satisfy the demand during peak hours. Consequently, the installed heat generation capacity for domestic hot water, and space heating in the buildings sector declines from about 200 GW in 2020 to 113 GW in 2050 (Figure 3.9). Heat supply is being electrified quickly so that all the residential and commercial heating demand is covered by heat pumps and some residual direct electric heating in 2040 already. The installed capacity of heat pumps almost doubles from 46 GW to 86 GW between 2020 and 2030, and then increase by 30% between 2030 and 2050 to reach 115 GW.

Similarly, in the industrial sector, heat supply is electrified quickly. Low and medium temperature heat supply in the industry is electrified early in the transition, while fossil fuels use in high temperature industrial processes are substituted by e-fuels, namely synthetic hydrogen and methane, only in the later steps of the transition (Figure 3.10), due to the high cost of production of e-fuels compared to the expected price of fossils fuels. The fossil-based heat generation capacities that will not have reached the end of their technical lifetime are considered stranded investments. In 2050, high temperature process heat demand is supplied by e-fuels,[30] while medium temperature heat demand is covered by industrial scale heat pumps, direct electric heating, and sustainable biomass to a very limited extent as resources are limited in Japan.

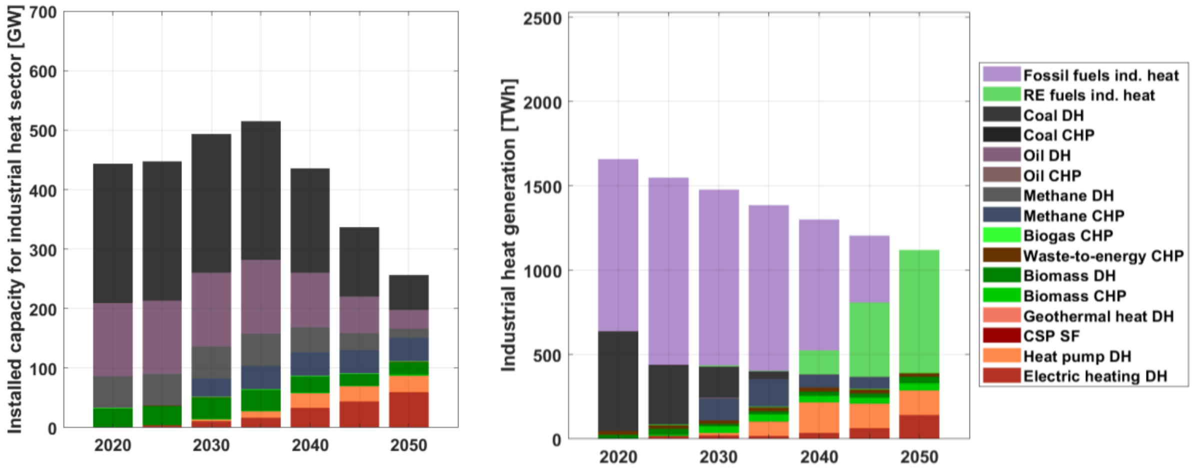


Figure 3.10: BPS (Autarky) – evolution of heat generation capacity (left) and heat generation (right) in the industrial sector from 2020 to 2050.

Transport

Final energy demand in transport sector declines drastically from around 870 TWh in 2020 to about 210 TWh by 2050 (from 22% to 8% of TFED), mainly due to efficiency gains and electrification (Figure 3.11). Direct electrification is primarily expected to develop in road transport with the adoption of battery-electric and plug-in hybrid vehicles in all the segments (light, medium and heavy-duty vehicles including buses), as well as rail transport [11]. Direct electrification of transport covers about 18% of final energy demand in transport in 2030 and about 48% in 2050. This corresponds to 12.5 million EV in 2030 and 44 million in 2050 (compared to about 1 million EV as of today). The electrification of road transport will bring additional benefits by providing flexibility to the power system with smart charging and vehicle-to-grid technologies.

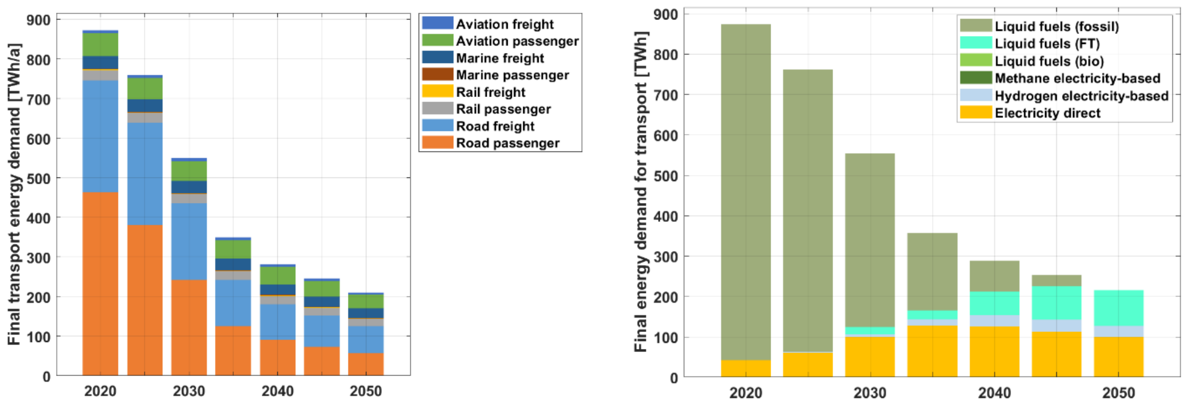


Figure 3.11: BPS (Autarky) – evolution of final energy demand for the transport sector – by mode (left) and fuel type (right) from 2020 to 2050.

[30] Some fossil heat generation capacity that can be converted to be used with e-fuels such as gas technologies are further used in 2050.

Where direct electrification is currently difficult, indirect electrification will be needed through electricity-based decarbonized synthetic fuels such as green hydrogen, synthetic methane, and mostly Fischer-Tropsch (FT) fuels. This will be the case particularly for maritime transport and aviation. It is assumed that biofuels do not play an important role due to limited access to sustainable resources in Japan and limited scalability of imports. Demand for sustainable e-fuels kicks in from 2035 onwards until 2050, mostly FT fuels that are imported, due to their very high cost if locally produced (69 TWh out of 89 TWh of FT fuel demand will be imported). In this autarky scenario, the limited amount of domestically produced synthetic fuel necessary in 2050 in the transport sector (22% of final energy demand for transport) will require 44% of the 180 TWh_{el} of power needed in 2050 for direct and indirect electrification of transport.

Energy storage

As seen earlier, storage plays an important role over the transition in providing flexibility to the system, as conventional capacities are phased-out and replaced by renewables. Installed electricity storage capacity nearly doubles in 2030 (61 GW or 0.32 TWh) and quadruples in 2050 (128 GW or 0.66 TWh) in comparison to 2020 (28 GW or 0.18 TWh), while the output increases from around 17 TWh_{el} in 2020 to 211 TWh_{el} in 2050 (Figure 3.12).

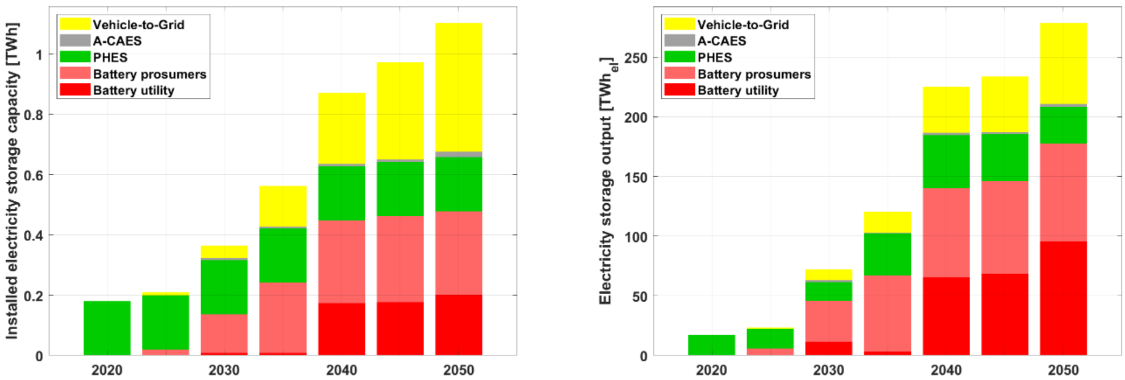


Figure 3.12: BPS (Autarky) – evolution of installed electricity storage capacity (left) and electricity storage output (right) from 2020 to 2050.

Pumped hydro energy storage (PHES) initially built to balance coal and nuclear generation switches to support variable RE capacities. Its use will increase during the transition, although the storage capacity will not increase. Indeed, from 2030 onwards, significant battery storage capacity will be built by prosumers and later by utilities too. By 2050, prosumer and utility-scale batteries will contribute 64% of all electricity storage throughput, while V2G will contribute about 24%, and PHES about 11%. Adiabatic compressed air storage (A-CAES) will play a limited role due to its high cost and low roundtrip efficiency (about 1%). During the last years of the transition, the system slightly decreases the use of PHES due to its higher losses compared to modern battery storage technologies.

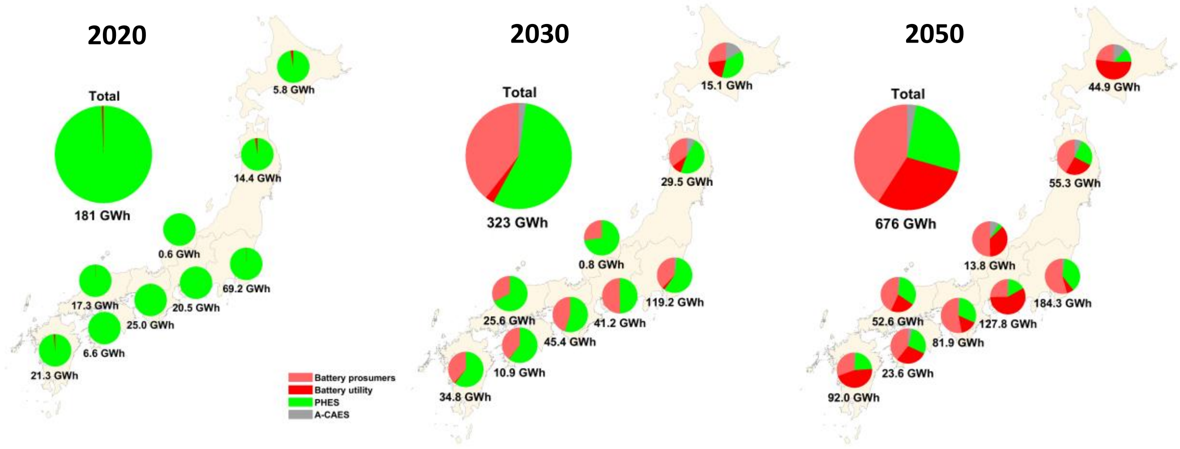


Figure 3.13: BPS (Autarky) – regional electricity storage capacities in 2020, 2030 and 2050.

In the scenario, storage capacity is being built in all the regions, but the system prefers to store electricity close to the load centers rather than in the generating regions (Figure 3.13). In the western and central regions, storage capacities have daily cycles supporting PV generation. On the contrary, in regions such as Hokkaido and Tohoku that export most of their wind generation, storage tends to have higher number of cycles over the year to compensate for the higher variability of wind generation and to increase the utilization of transmission grids (Figure 3.14).

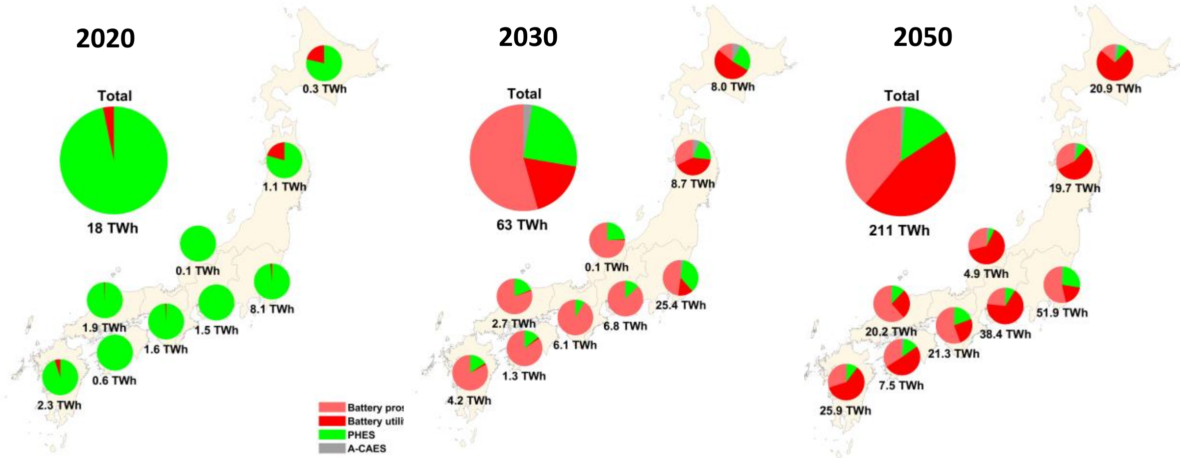


Figure 3.14: BPS (Autarky) – regional electricity storage generation in 2020, 2030 and 2050.

Similarly, heat storage plays a critical role in balancing heat supply and peak shaving, which is reflected in the decrease of installed heating capacity. It is below 1 TWh until 2045 but increases significantly to over 110 TWh in 2050 to store synthetic methane for industrial use that replaces fossil gas (Figure 3.15, left). Heat storage output more than quadruples in the same period, synthetic methane storage accounting for half of it in 2050 (Figure 3.15, right). Low and high temperature thermal energy storage (TES) play an important role during the whole transition in providing flexibility to the heat supply. Low temperature heat storage capacity is directly linked to low temperature industrial heat, space and water heating, while high temperature TES and methane storage is linked to industrial heat demand. Heat storage is mostly used as a buffer for peak demand shaving with high cycles over the year, methane storage is used as a seasonal storage, as shows the annual throughput that is only slightly higher than the storage capacity. In order to fully decarbonize industrial heat in 2050, important investments in synthetic methane storage are required. More realistically, those investments would be distributed more evenly from 2035 to 2050, over the transition.

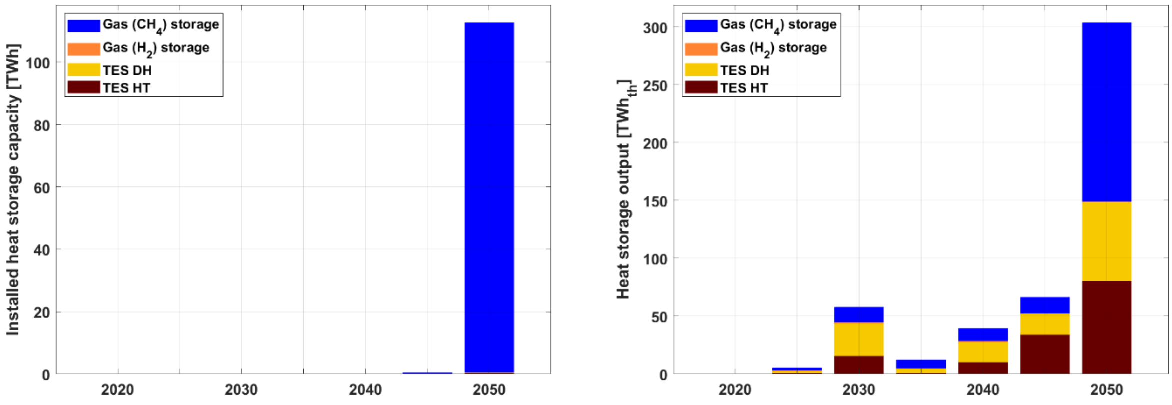


Figure 3.15: BPS (Autarky) – evolution of installed heat storage capacity (left) and heat storage output (right) from 2020 to 2050.

Synthetic fuels

Electrolyzers are an integral part of the synthetic fuel production chain and provide crucial flexibility to the energy system. E-fuels are produced at the consumption site. As such, the highest installed capacity of electrolyzers can be seen in Tokyo. A total of around 197 GW_{el} of electrolyzer capacity is needed in 2050 to cover the demand of e-fuels in the industrial and transport sectors that increases to about 840 TWh_{th} in 2050, of which about 70% of hydrogen (600 TWh or 15 Mt, higher calorific value).

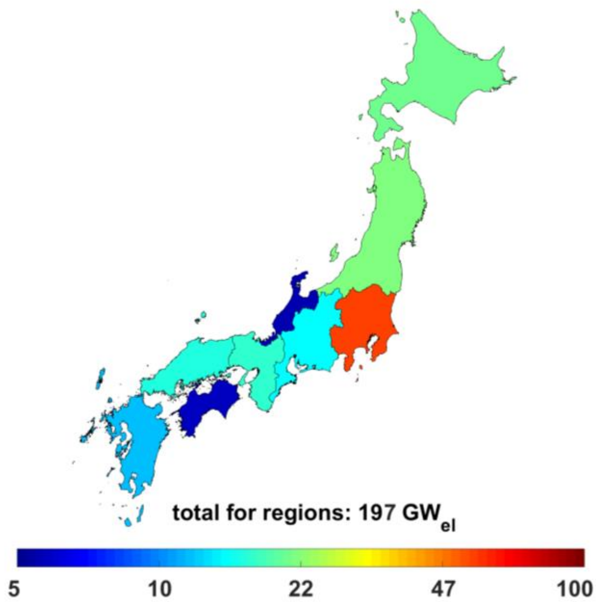


Figure 3.16: BPS (Autarky) – regional electrolyzer capacity in GW_{el} in 2050.

In this autarky scenario, electrolyzer capacity increases sharply after 2040 to supply the demand in the industry and transport sectors. A 20% decrease in demand by 2050 leads to a decrease of 27% in electrolyzer capacity (Figure 3.17, BPS Low20). Importing about 50% of e-fuels demand leads to a 63% decrease, although the consumption slightly increases (BPS all import).[31] Hydrogen is not used for storage, the role of hydrogen storage being limited over the transition to buffer hydrogen required for the production chain of synthetic methane and FT-fuels.

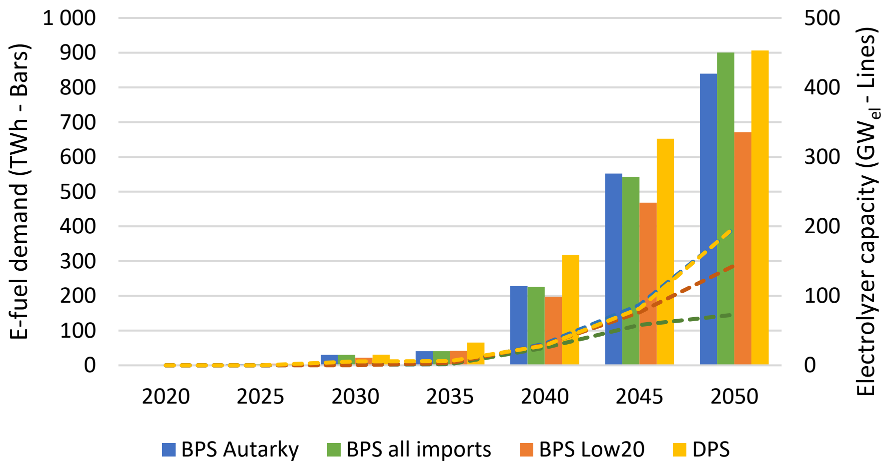


Figure 3.17: Evolution of e-fuel consumption and electrolyzer capacity from 2020 to 2050 in the main scenarios.

3.3. Costs and investments

Annual system costs

The annual system costs represent the yearly average costs of the whole energy system calculated in 5-year intervals. Annual system costs in 2050 are 15% lower than today. They decline significantly from around 24 700 b¥ (225 b$) in 2020 to about 21 000 b¥ (191 b$) in 2050 after a slight increase in 2030, representing about 3.7%-4.4% of current GDP.[32] This slight increase in 2030 is due to an increase in investments and CO_2 price in the power sector while the costs in other sectors stagnate. The power and transport sectors transitioning quickly afterwards, reducing their overall costs, the heat sector becomes the main cost driver by 2050. The transition requiring significant investments into new decarbonized technologies, energy system costs related to capital expenditure (CAPEX) steadily increase throughout the transition, compensated by the decline of fossil fuel consumption (Figure 3.18, right).

[31] Synthetic fuel demand includes intermediate demand, such as hydrogen needed to produce synthetic methane or FT fuels partly only produced to store power, or hydrogen and synthetic methane used for power generation. Consumption only includes final demand for those e-fuels, mostly in the industry and transport sectors.

[32] GDP in 2019 in current yens amounted to 561 267 b¥, about 5.1 trillion $. See Cabinet office – Government of Japan, GDP (Expenditure Approach) and Its Components, December 2020

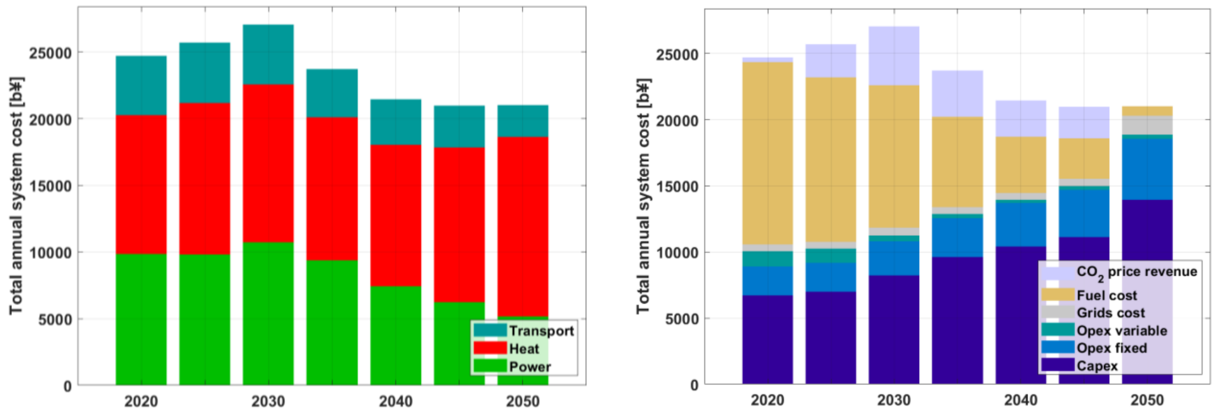


Figure 3.18: BPS (Autarky) – annual system costs per sector (left) and cost component (right) from 2020 to 2050.

The reduction of fossil fuel and uranium imports, that represent nearly half of the overall system cost in 2020, provides savings of nearly 145 000 b¥ (1300 b$) from 2020 to 2050. These savings can stimulate domestic investment instead, supporting the development of domestic industries such as renewable energies, electric vehicles, electrolyzers, efficient heat pumps for space heating but also industrial heat etc.

The cumulative cost through the transition will reach 709 000 b¥ (6 445 b$), including annualized capex, OPEX, fuel costs and CO_2 price revenue. The cumulative cost would be about 10% lower if CO_2 price revenues were not taken into account, considering they will return to the economy in the form of subsidies or support measures for climate investments or environment protection.

Levelized cost of energy

The levelized cost of energy – average cost of the energy consumed in the system – is calculated as the total cost of energy production divided by the final energy consumption. It increases by about 30% between 2020 and 2030, from 6 150 ¥/MWh (56 $/MWh) to 8 000 ¥/MWh (72 $/MWh), and stagnates afterwards until 2050 (Figure 3.19, left). The levelized cost of energy is increasingly dominated by capital costs as imported fuel costs continue to decline throughout the transition, which could imply an increased level of energy diversification and self-reliance in Japan.

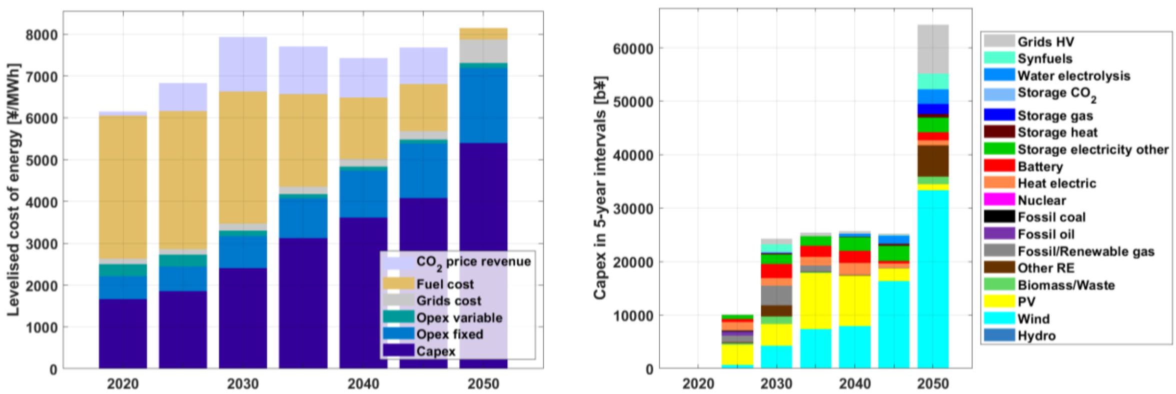


Figure 3.19: BPS (Autarky) – evolution of levelized cost of energy (left) and cumulative capital expenditures in five-year intervals (right) from 2020 to 2050.

Capital expenditures are well spread across a range of technologies with the majority of investments in the power sector, mostly in wind energy followed by solar PV (Figure 3.19, right). Yearly capital investment needs increase quickly until 2030 and then stagnate: from 2 000 b¥/year (18 b$/year in 2021-2025, to nearly 5 000 b¥/year (45 b$/year) from 2026 to 2045. They peak during the last step of the transition, at 13 000 b¥/year (117 b$/year) in 2046-2050, as the remaining fossil fuels in power, heat and transport sectors are being substituted. This increase is mostly compensated by a decrease in fossil fuel imports and CO_2 price revenue.

Levelized cost of electricity

The levelized cost of electricity (LCOE) is the average cost of electricity consumed in the system, made up with generation, storage, curtailment and grid costs. It increases from 12 800 ¥/MWh (116 $/MWh) in 2020 to 15 000 ¥/MWh (136 $/MWh) in 2030 due to the accelerated RE introduction and increasing carbon pricing, and later declines by 43% to 8 450 ¥/MWh (77 $/MWh) in 2050 thanks to the integration of low-cost RE generation and reduction of fossil fuel cost to zero (see Figure 3.20, left). From 2035 onwards, over 50% of the LCOE is due to CAPEX, as fuel costs (including CO_2 pricing) decline through the transition. Hokkaido has the lowest LCOE in 2050 at around 7 200 ¥/MWh (66 $/MWh), between 9 and 29% lower than in the other regions. The highest average LCOE are found in Shikoku and Chugoku at around 10 100 ¥/MWh (92 $/MWh) and 9 650 ¥/MWh (88 $/MWh) respectively by 2050. Indeed, the Shikoku region is mostly self-sufficient but has a generation mix with 64% of offshore wind (Figure 3.5) that has higher costs than PV or onshore wind. In Chugoku, the installed RE capacities reach their upper limit between 2046 and 2050, leading to a stark increase in power imports from other regions to 66% of demand in 2050. This implies additional grid and storage in order to balance the system, adding to the costs. It remains cheaper to build local generation capacities than to build them elsewhere as well as grids to transport power.[33]

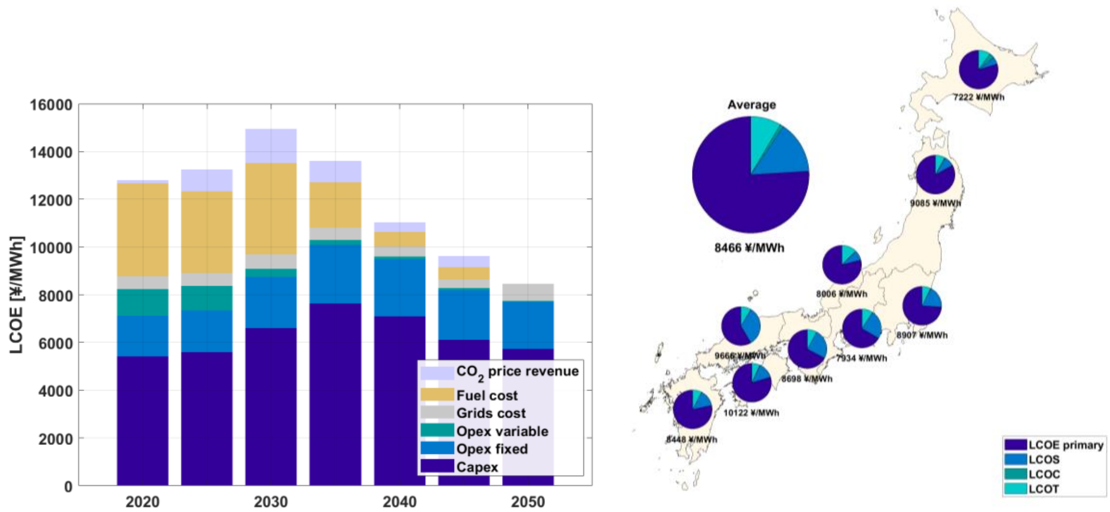


Figure 3.20: BPS (Autarky) – levelized cost of electricity per cost component from 2020 to 2050 (left) and per region in 2050 (right)

[33] The grid reinforcement and development costs were calculated based on the assumption that the grids' NTC limits were going to be relaxed after 2030 for the AC lines, to optimize the use of the interconnections. If the NTC remained at 50% as it is the case today for most of the AC lines, the LCOE would be about 8% higher due to additional grid reinforcement costs.

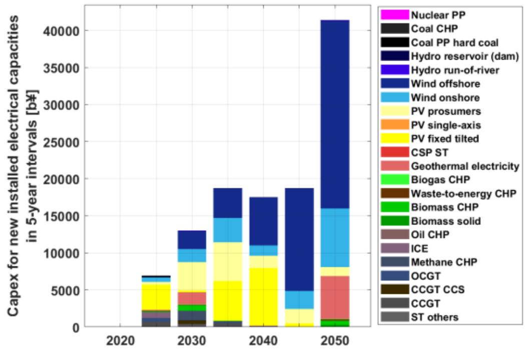


Figure 3.21: BPS (Autarky) – capital investment in generation capacities in five-year intervals

The investments are well spread across a range of power generation technologies with the highest share in offshore wind, followed by solar PV (Figure 3.21). In this autarky scenario, investments peak in 2050, when significant capacity has to be built to satisfy energy demand of e-fuels production.

Levelized cost of heat

The levelized cost of heat (LCOH) – average cost of heat consumed in the system – consists of generation (including CO_2 price) and storage costs. Contrary to LCOE, it almost doubles during the transition, from around 4 000 ¥/MWh (36 $/MWh) in 2020 to around 7 600 ¥/MWh (69 $/MWh) in 2050 (Figure 3.22, top left). Indeed, heat demand is driven mainly by industrial process heat. Here, cost grows quickly after 2040 as fossil fuels are switched to e-fuels where heat source cannot be electrified (Figure 3.22, bottom left). Space and water heating cost in the building sector declines steadily over the transition with further efficiency gains and the introduction of heat pumps, allowing to electrify 100% of residential and commercial heat demand by 2040.

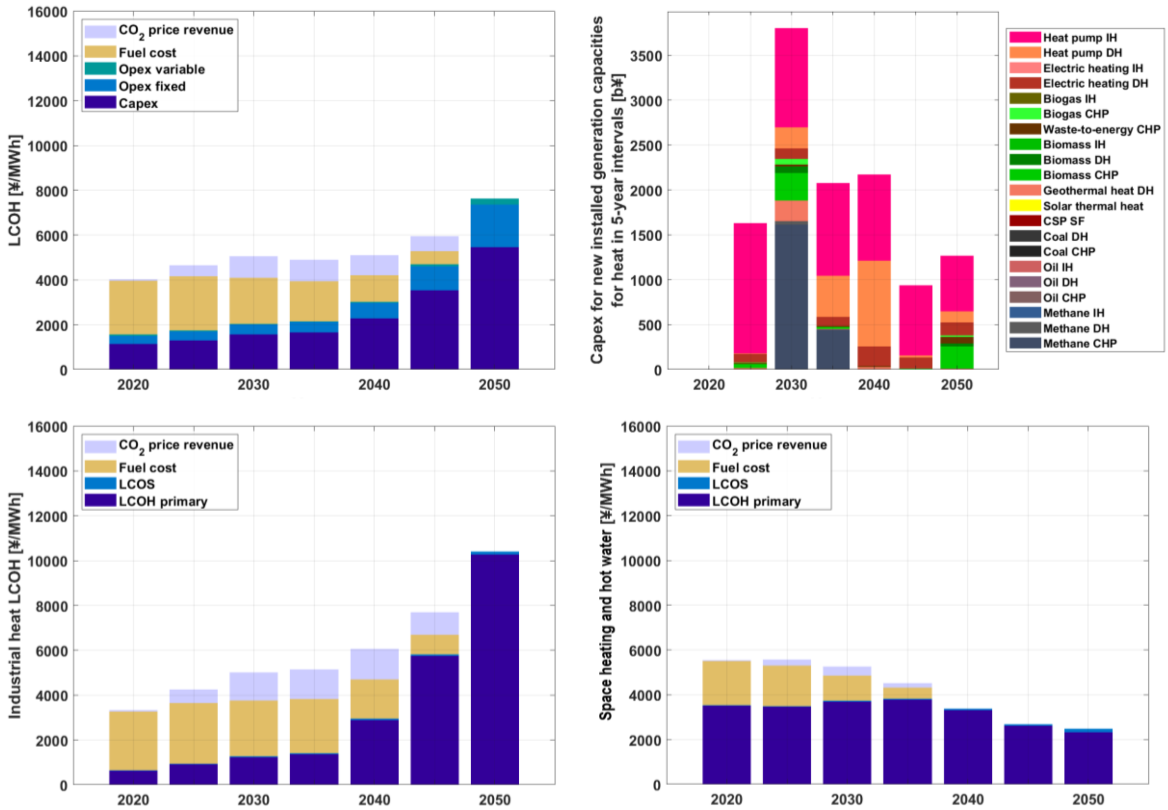


Figure 3.22: BPS (Autarky) – evolution of levelized cost of heat (top left), cumulative investment in generation capacities in five-year intervals (top right), LCOH for industry (bottom left) and LCOH for the building sector (bottom right) from 2020 to 2050.

Similar to LCOE, CAPEX becomes the largest cost component for heat as fossil fuel use declines over the transition. The investments mainly go towards heat pumps (individual and for industrial heating), but also some electric heating in industry and 5 GW of biomass CHP and utility-scale heat plants (for district heating and low temperature heat in industry) (Figure 3.22, top right). Most of the investments occur in 2026-2030, when the system builds additional gas CHP capacity to partially substitute coal use for industrial heat. Hokkaido and Tohoku have the highest average LCOH, due to seasonality of the climate with high peak heat demand in the winter months, and higher reliance on heat storage.

Costs of synthetic fuels

Even though most of the energy system can be directly electrified, some processes in the industry, maritime and aviation transport, and the remaining combustion vehicles will still require the use of liquid fuels. In order to fully decarbonize the energy system, fossil fuels used in these processes have to be substituted by biofuels or synthetic fuels. Due to limited access to sustainable biofuels in Japan and limited scalability of imports, synthetic fuels are expected to provide a notable portion of the fuels required for a complete defossilization of the industry and transport sectors. Yet, the cost of production of sustainable e-fuels expected for Japan by 2050 are significantly higher than the cost of fossil fuels (Figure 3.23).

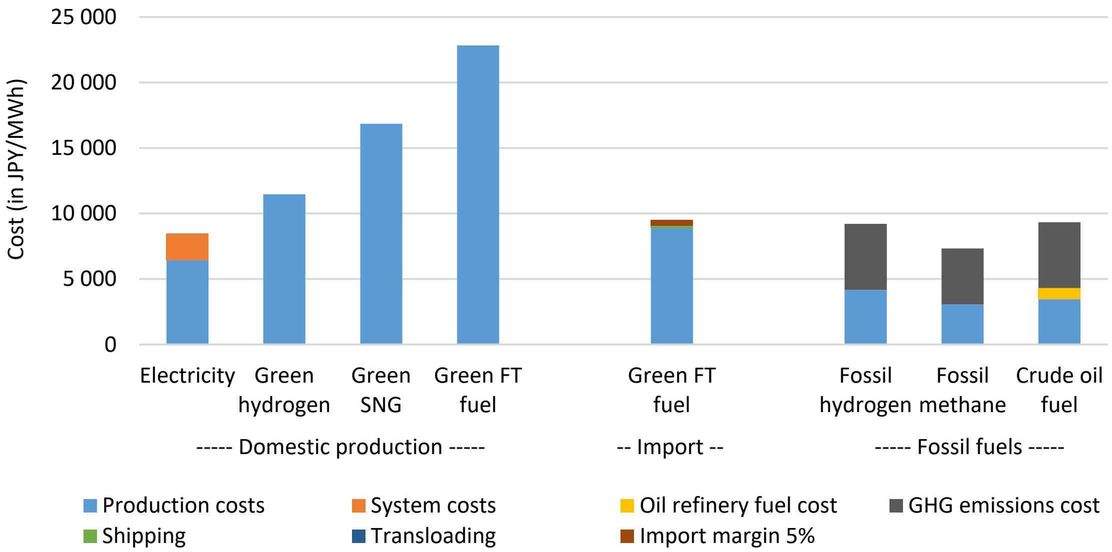


Figure 3.23: BPS (Autarky) – fossil and synthetic fuel costs in 2050

In a power-based energy system, renewable electricity becomes the cheapest energy carrier, with costs comparable to fossil fuels (when including carbon pricing). The cost of e-fuels produced from electricity depends mostly on the overall efficiency of the synthesis processes and partially on their CAPEX. As such, green hydrogen is the cheapest e-fuel and will play a central role in the industrial sector, while synthetic methane and FT-fuels – that use synthetic hydrogen in their production process – are significantly more expensive due to additional equipment costs and higher losses in the synthesis process. FT fuels are thus almost three times more expensive than green hydrogen. Synthetic methane will still be produced and used for a seasonal energy storage mostly to cover the industrial demand during energy deficit periods, as storing hydrogen is more expensive. FT fuels are mostly imported to cover the demand of the transport sector, FT fuels cost largely determining the final cost of energy for the sector by 2050 (see Figure 3.24).

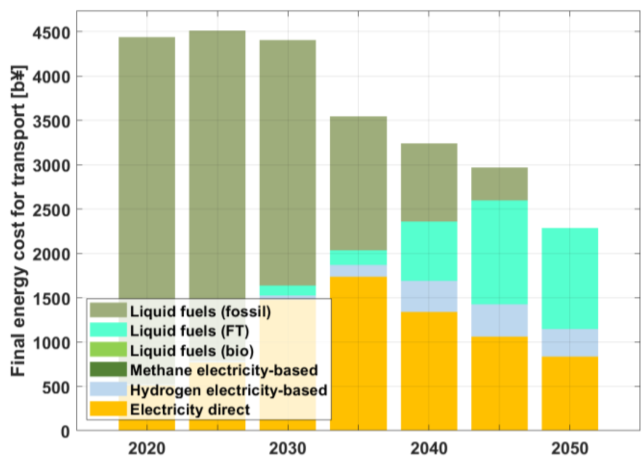


Figure 3.24: BPS (Autarky) – evolution of final energy cost for transport per fuel type from 2020 to 2050.

As seen in the previous section, the use of e-fuels significantly impacts the cost of heat for industry, but also for the transport sector, consequently leading to higher overall energy system cost. Direct electrification remains the most efficient solution where possible, and the use of synthetic fuels should be limited to the minimum. Importing sustainable e-fuels from abroad (see section 4) could also significantly decrease the cost of industrial heat and transport, as long as their availability in sufficient amounts can be secured.

Overall, Base Policy Scenario shows that a fully sustainable energy system can be built in Japan and the energy related emissions can be reduced to zero by 2050 by producing almost all of the required energy domestically. The accelerated decarbonization will allow to fulfill the 1.5-degree scenario target by reducing the energy related GHG emissions in 2030 by 39% and in 2040 by 78% from 2020 levels. The results show that the maximum capacity of renewables that can be installed in Japan is sufficient to cover most of the country's energy demand: only 3% of TPES is imported in 2050. This energy autarky will demand the utilization of very large amounts of renewables: 524 GW of solar PV, 144 GW of onshore wind and 200 GW of offshore wind. This leads to a lower LCOE in the RE based system than today. At the same time, energy autarky also leads to cost increase of the heat supply for the industry due to higher cost of locally produced e-fuels compared to fossil fuels. Importing those e-fuels or green electricity from regions with less limited RE resources will allow to decrease the cost of energy, which is explored in the next section. Further actions supporting the deployment of RE technologies including releasing administrative constraints and adapting the power system to adjust to variable production would also help achieving the same target in a self-sufficient energy system.

4. Base Policy Scenario with power and e-fuels imports

The BPS autarky scenario shows that domestic RE resources are sufficient to reach full defossilization and an almost self-sufficient energy system by 2050. However, it comes at the cost of high utilization of local RE resources, high dependence on grids and electricity exchange between the regions, and finally higher energy costs, especially for the industrial processes. Imports of sustainable energy in form of electricity or e-fuels could release some of those constraints and achieve lower cost of energy supply.

To investigate the impact of sustainable energy imports on the energy system, two additional sensitivity scenarios were tested based on the BPS scenario. In one scenario, import of renewable e-fuels from Australia is possible after 2030 as well as renewable electricity imports from Russia and China/Korea, all other things being equal. In the other scenario, power import only is possible after 2030.

This first scenario will be analyzed in more details in the following sections. Also, the analysis will focus on the period 2035-2050, the years 2020-2030 being the same as in the BPS autarky scenario since the impact of the imports on the energy system are visible only from 2035.

4.1. General outlook

In this scenario, green synthetic fuels such as synthetic methane or hydrogen can be imported, additionally to the Fischer Tropsch fuels that can be imported in all scenarios. The volume of imported e-fuels was limited to 50% of total e-fuels consumption, so that the rest must be covered by local synthesis units. Additionally, renewable electricity can be imported from Russia through Hokkaido in the north of Japan, and from China via Korea with an entry point in Chugoku, in the west of Japan. In 2035, 2 GW of grid interconnections were assumed to be available for each route, increasing to 10 GW each in 2045-2050, with a maximum capacity factor of 80% amounting to maximum power imports of 28 TWh_{el} per year starting 2035 and 140 TWh_{el} per year between 2045 and 2050.

Similar to the BPS scenario, the scenario with e-fuel imports shows a rapid decline in GHG emissions, especially after 2025, reaching zero GHG emissions in the energy consuming sectors in 2050 (Figure 4.1).[34] By 2030, GHG emissions decrease by 39% from 2020 levels, and by 49% from 2013 levels, fulfilling the NDC target for 2030, and by 45% relative to 2010 levels - exactly the 1.5°C scenario target.

[34] The GHG emissions until 2018 are historical data from the National Greenhouse Gas Inventory Report of Japan 2020 published in the UNFCCC format. The 2018 values for non-energy related emissions and carbon sinks through LULUCF are prolonged as a reference for the year 2020 and are shown to decline linearly after that to reach the level of the carbon sinks so that Japan reaches net zero emissions in all sectors by 2050.

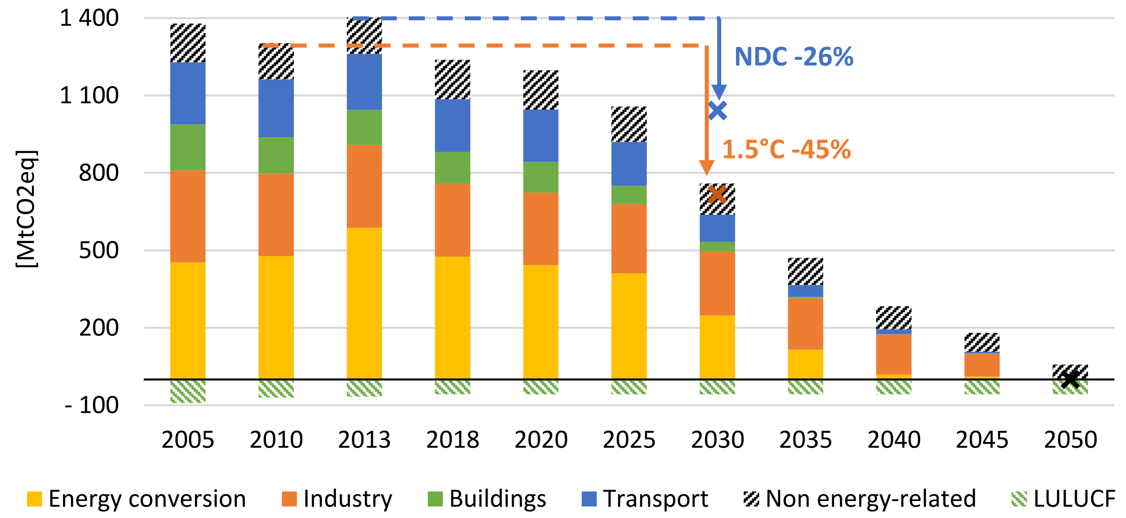


Figure 4.1: BPS all import – evolution of energy-related GHG emissions per sector and current climate targets.

The energy imports do not lead to significant reduction in cumulative GHG emissions, which can be explained by their late introduction: most of the emissions occur before 2035 and the import amounts available in 2035 are still very limited and increase slowly in later periods. The difference in yearly emissions start to show in 2040, when the imports scenario has about 17% less emissions than the BPS scenario. In 2045, the difference grows to 30%. This difference is mostly seen in the energy conversion, building and industry sectors, which decarbonize more quickly thanks to imports compared to the autarky scenario. This allows all the sectors except the industry sector to be nearly decarbonized by 2045. The cumulative GHG emissions reach 13.7 $GtCO_{2eq}$ from 2020 to 2050, about 3.9% lower than in the BPS scenario without imports.

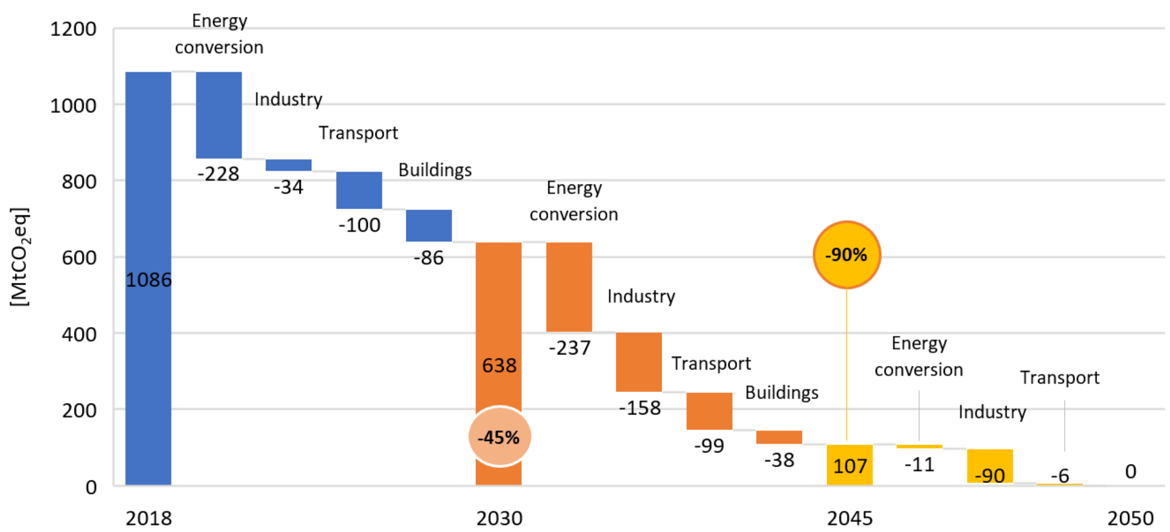


Figure 4.2: BPS all import – evolution of energy-related GHG emissions per sector in 3 steps.

**Emissions reductions relative to 2010*

The building sector would be the first sector to decarbonize, its emissions decreasing by 68% between 2020 and 2030, and the sector fully decarbonized by 2040. The energy conversion sector, an important sector considering the increasing electrification of energy uses, will also reach -44% of emissions by 2030 and -98% by 2040. The transport sector undergoes a rapid decarbonization with its emissions halved between 2020 and 2030 and achieving an emissions reduction of 97% by 2045. The emissions in the industry sector decline more slowly than in the other sectors, as medium and high temperature heat can only be defossilized in the later stages of the transition. The emissions decline only by 12% between 2020 and 2030, and by 68% until 2045, the remaining emissions drastically eliminated in the last years of the transition.

Indeed, the BPS scenarios foresee a transition from fossil fuels to renewable energy technologies in all energy uses combined with a quick electrification and a decrease of about 35% in final energy demand. Efficiency improvements on the demand side (mostly due to the electrification of the transport sector and increased motor efficiency) lead to a 15% decline in primary energy demand (PED), and efficiency improvements on the supply side (mainly due to renewable-based electrification of low and mid temperature heat (heat pumps)) to a further decline by 19%. This translates in this specific scenario into a 54% drop in PED, from about 4,600 TWh in 2020 to about 2,100 TWh by 2050, the power and e-fuels imports allowing for an additional 10% decrease in 2050 (see Figure 4.3). Consequently, the energy system relies on 32% imports in 2050, down from 90% today.

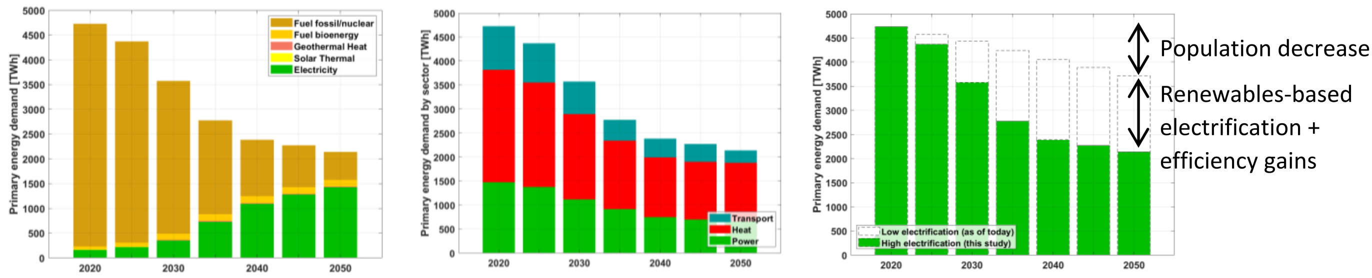


Figure 4.3: BPS all import – evolution of primary energy demand per energy carrier (left), per sector (middle), and efficiency gain in primary energy demand (right) from 2020 to 2050.

The heat and transport sectors evolve in this scenario exactly as in the BPS scenario without imports. This analysis will thus not be repeated, please refer to section 3.2. The following sections will analyze the energy transition pathway on all the other differing points.

4.2. Energy supply and storage

Power

The electrification and defossilization of the energy system lead to a substantial increase in power demand, especially at the latest stage of the transition as all the fossil fuels are being banned. As this scenario can rely on green e-fuels and power being imported from abroad at reasonable costs, power demand gradually increases between 2020 and 2050 but only by 50%, and power generation by 40% (+ 1% on average per year), while total installed capacity almost triples from around 240 GW in 2020 to about 760 GW in 2050, of which 88% would be wind and solar power, up from 27% in 2020 (Figure 4.4). Power generation is covered to 100% by RE, up from 18% in 2020.

All the BPS scenarios rely equally on solar PV, reaching the maximum capacity of solar PV set in this study (524 GW by 2050). Since coal and nuclear generation are phased-out by 2030, 22 GW of gas CHP plants are also being built and fill about half of the supply gap. The rest is covered by newly installed solar PV and onshore wind capacities (144 GW solar PV and 25 GW wind installed capacities by 2030). After 2030, sustainable e-fuel imports reduce the need for building additional most expensive RE that are mostly built otherwise in the later stages of the transition to supply power for the national production of e-fuels. Solar PV is being built first since it is the least cost energy source, reaching 524 GW in 2050 (in both the autarky and import scenarios), the maximum capacity set in this study. Offshore wind is being built much less, with a total installed capacity of 63 GW in 2050 (137 GW less than in the "autarky" scenario), as well as onshore wind with 88 GW (56 GW less than in the "autarky" scenario). This amounts to an annual installed capacity of 8.4 GW of solar PV, 1.5 GW of onshore wind, and 0.7 GW of offshore wind between 2021 and 2030, and of 20 GW of solar PV, 3.7 GW of onshore wind, and 2.8 GW of offshore wind between 2031 and 2050. In this scenario, solar power is the largest supplier of electricity starting 2040 (52% of generation by 2050). The capacity installation rates stay rather constant in 2031-2050, without a sharp peak of installation in 2046-2050, observed in autarky scenarios.

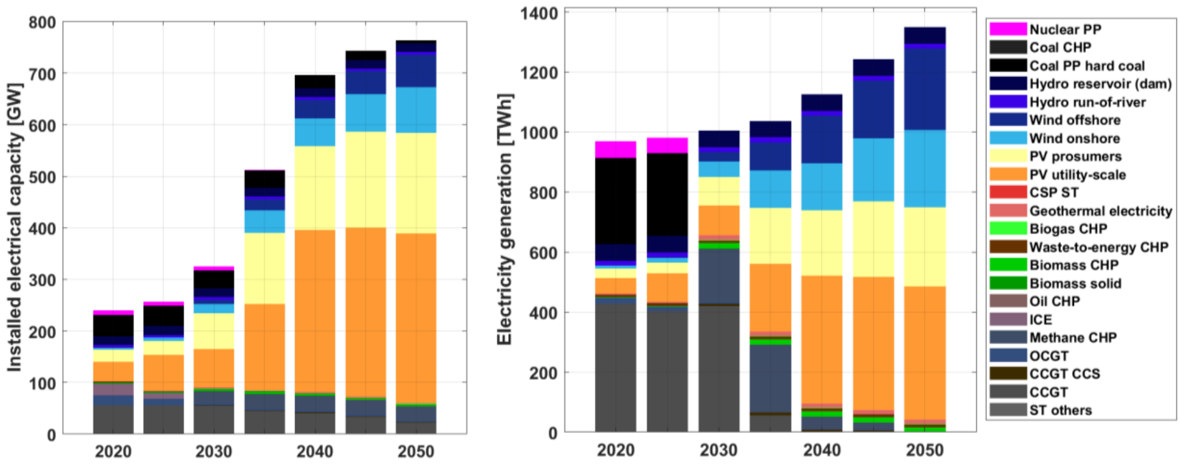


Figure 4.4: BPS all import – evolution of power generation capacity (left) and generation (right) from 2020 to 2050.

The modeling results additionally show that renewable capacities are distributed unevenly across the country (Figure 4.5). Solar PV capacities are well spread, representing the majority of the installed capacities in almost all the regions. The vast majority (68%) of onshore wind is built in Hokkaido and Tohoku, the 2 northern regions with comparably low population density and high wind potential, while offshore wind mostly in Tokyo (40%) and Kyushu (20%). Power imports from the north reduce mostly the need for generation capacities in Hokkaido, while the differential in installed capacities and generation is spread among the regions in the south, as Chugoku relies strongly on interregional power imports.

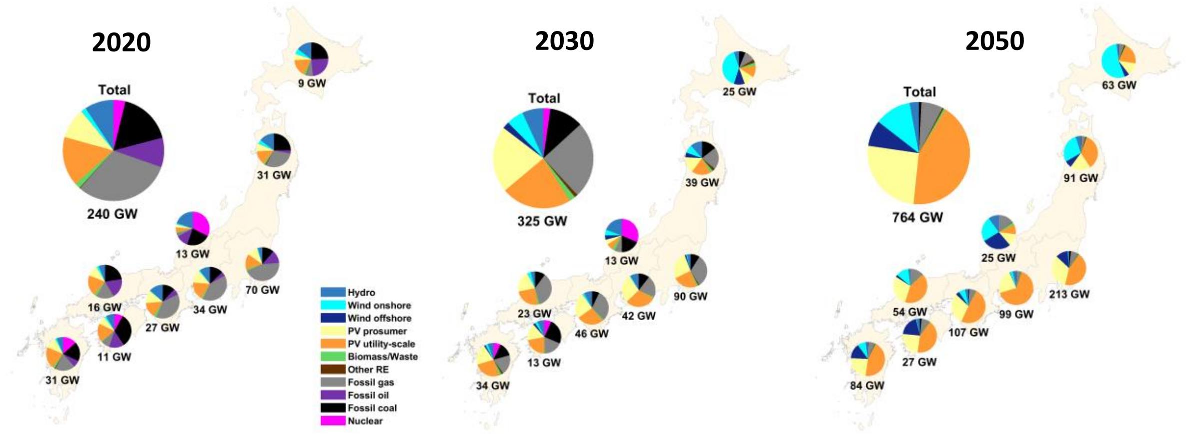


Figure 4.5: BPS all import – regional electricity generation capacities in 2020 (left), 2030 (center), and 2050 (right).

The land issues related to renewable capacity installations and their respective need for space are often raised as a concern in Japan. According to the scenario, utility-scale PV (328 GW) will use about 1.3% of land area, while onshore wind will use 2.3%. This shows rather limited land area is needed to install this large amount of renewable capacity in Japan.

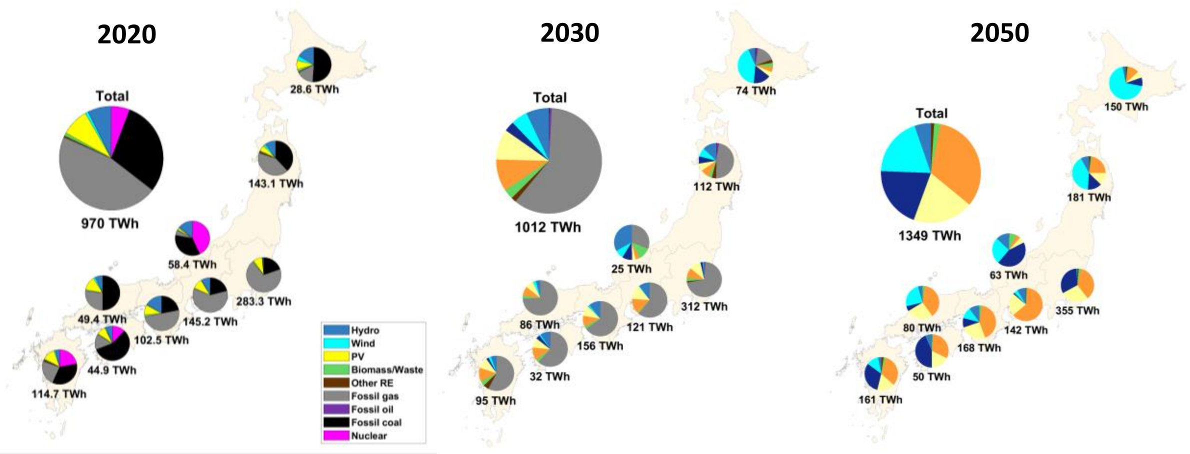


Figure 4.6: BPS all import – regional electricity generation in 2020 (left), 2030 (center) and 2050 (right).

Imports have no impact on the behavior of power prosumers. As in the BPS autarky scenario, prosumer PV capacity grows fast, increasing from 23 GW in 2020 to 70 GW by 2030. By 2050, prosumers capacity reaches 196 GW. Indeed, electricity imports from China/Korea and Russia and e-fuel imports affect the centralized energy supply, but power demand in the residential, commercial and industrial sectors stays the same. Thus, the behavior and prosumer PV capacity does not change. As power consumption in the system decreases due to lower inland e-fuels production, only the share of prosumers in the power supply increases to almost 20% in 2050 (12% in BPS autarky). Similar to the BPS scenario, prosumer PV plays an important role in the densely populated central regions such as Tokyo, Chubu, Kansai, and Chugoku.

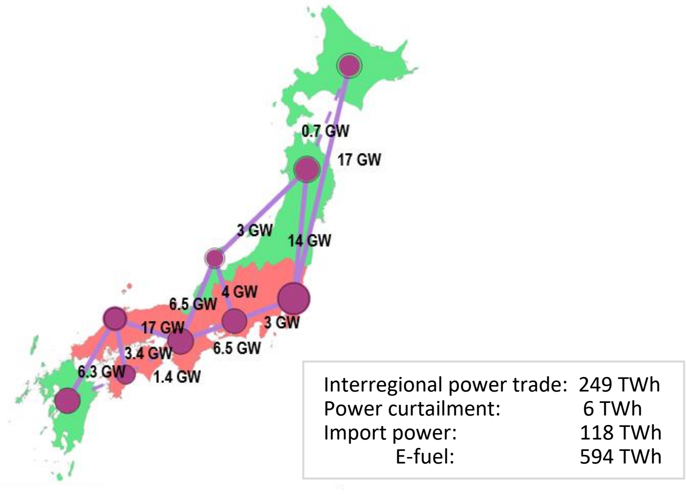


Figure 4.7: BPS all import – grid capacity and interregional power trade in 2050.

Interregional electricity trade increases by about two thirds from 2020 to 2050, to 249 TWh (18% of generation) (Figure 4.7). However, electricity imports, especially from China/Korea to Chugoku, as well as e-fuels imports decrease the need for power flow from the eastern regions to the west, compared to the BPS autarky scenario. Hokkaido exports about 80% of its total generation (120 TWh) as the largest exporting region, followed by Tohoku with 46 TWh (25% of its generation). Tokyo imports the most with 145 TWh (30% of its demand), followed by Kansai with 28 TWh (15% of its demand).

Interregional transmission grids are being built accordingly: 17 GW of direct connection from Hokkaido to Tokyo would be needed in 2050 though much less than in the autarky scenario with 60 GW. Other interconnections are reinforced and the 50/60Hz interconnection capacity grows to 6 GW which is much less than the 42 GW in the BPS autarky scenario. This shows both grid areas stay more self-sufficient in this import scenario.

In total, grid capacity and the role of the electricity trade between regions is much lower than in the BPS autarky scenario that needs about 100 GW more of interregional transmission grids spread across the country. Indeed, e-fuels imports reduce electricity demand for localized e-fuels production and the power demand of regions can be covered mostly by local resources, without large scale electricity transfers from the Hokkaido and Tohoku regions. Also, the seasonality of power supply and demand decreases compared to BPS autarky scenario.

Figure 4.8 illustrates how typical weeks in the summer and the winter look like in 2050. Thanks to e-fuel imports, power demand for e-fuels stays more stable throughout the year: the system only produces and stores some limited amounts of e-fuels in the winter, while in the summer with lower RE generation, less power needs to be used to produce e-fuels. Batteries, smart charging and V2G still play a central role in balancing the system, but the role of grids and demand response from e-fuels production decreases compared to BPS autarky case.

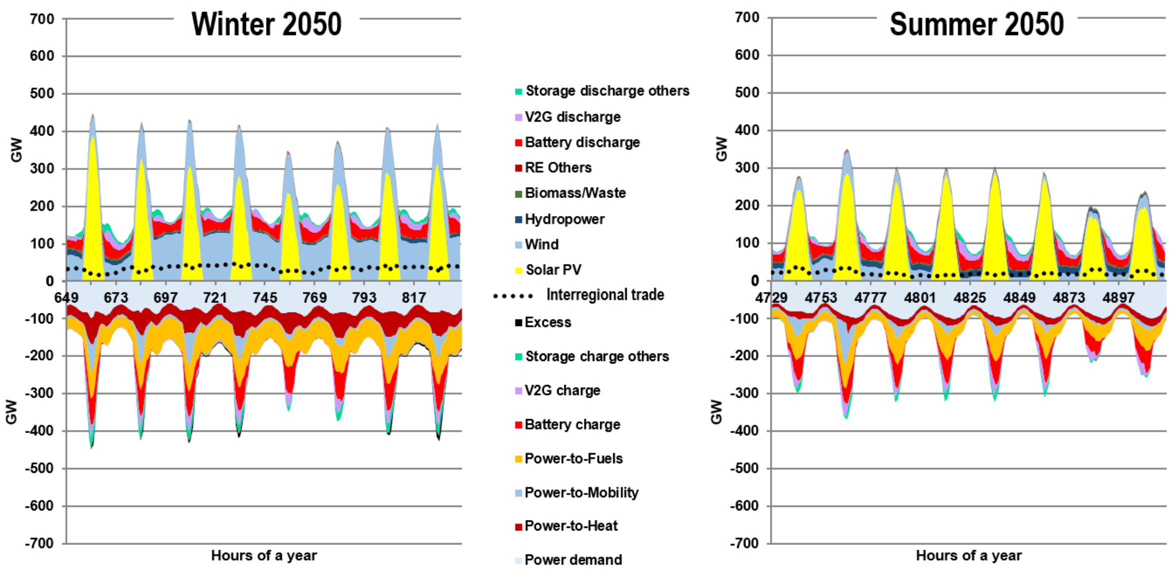


Figure 4.8: BPS all import – power system balance during winter (left), summer (right) week in 2050.

In 2050, the overall system capacity exceeds 750 GW (including VRE and flexible generation) and flexible demands adjust to the generation profile of variable renewables. Peak load reaches about 490 GW in winter at midday when solar PV and wind feed-in are high (Figure 4.8, left). This is 35% less than in the BPS autarky case. Flexible demand (storage, V2G charging, power-to-mobility, power-to-heat, power-to-fuels) is activated during those hours, pushing up the maximal load and resulting in a rather low curtailment level of renewables (less than 1.1% of total power generation). Since there is massive flexible demand, the peak load is much lower during hours of low renewables feed-in. It reaches only about 84 GW during those periods that occur mostly in summer at nighttime (Figure 4.8, right). This is 5% less than in the BPS autarky case. This load then represents the inflexible demand (in particular power for general applications, dumb charge in transport and partially power-to-heat, as some part cannot be buffered through heat storage). In this scenario, the Japanese system has enough flexible energy sources available to meet this inflexible demand in 2050 with 17 GW of hydro dams, 30 GW of pumped-hydro storage, 52.4 GW of gas turbines and gas CHP running on biogas and e-fuels, 5 GW of biomass power plants and CHP and 87 GW of battery storage. Plus at least 5 GW of wind capacity that are generating during every hour in 2050.

Energy storage

In this scenario, national power transmission grids add some flexibility to the system. Some of those capacities are freed by the phase-out of conventional capacities and can be used to balance renewables in-feed and consumption pattern between regions. Additionally, storage as well as electricity imports from China/Korea and Russia provide some additional flexibility to the system. Because the system can import both e-fuels and electricity, it needs marginally less storage capacity than in the BPS autarky scenario.

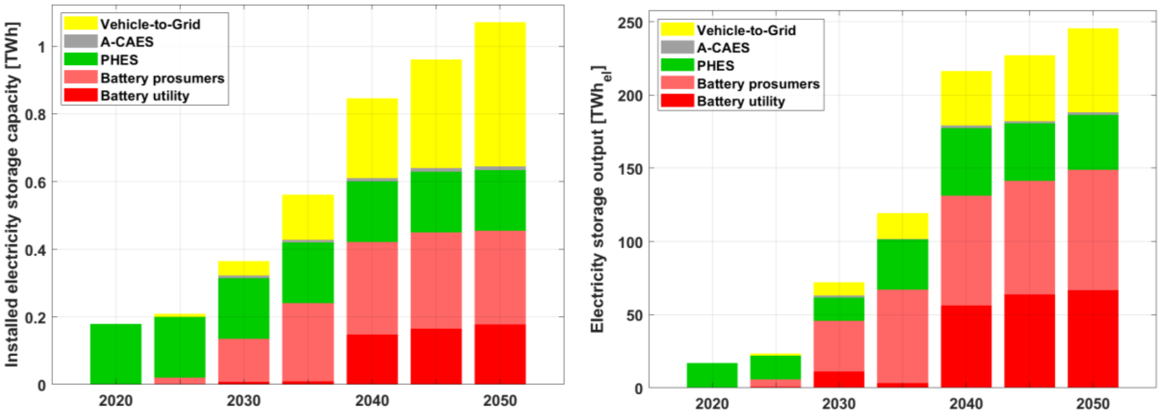
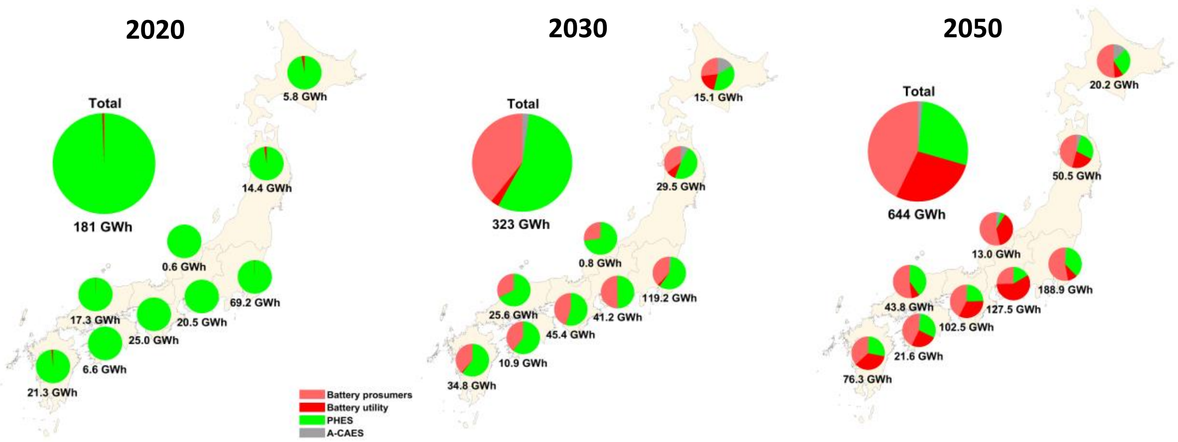


Figure 4.9: BPS all import – evolution of installed electricity storage capacity (left) and electricity storage output (right) from 2020 to 2050.

Installed electricity storage capacity nearly doubles in 2030 (61 GW or 0.32 TWh) and quadruples in 2050 (119 GW or 0.64 TWh) in comparison to 2020 (28 GW or 0.18 TWh), while the output increases 10 times from around 18 TWh$_{el}$ in 2020 to 188 TWh$_{el}$ in 2050 (Figure 4.9). Pumped hydro energy storage (PHES) initially built to balance coal and nuclear generation switches to support variable RE capacities. Its use will increase during the transition, although the capacity will not increase. Indeed, from 2030 onwards, significant battery storage capacity is built by prosumers and later by utilities too. By 2050, prosumer and utility-scale batteries will contribute 60% of all electricity storage throughput, while V2G will contribute about 25%, and PHES about 15%. Adiabatic compressed air storage (A-CAES) will play a limited role. During the last years of the transition, the system slightly decreases the use of PHES due to its higher losses compared to modern battery storage technologies.

In the scenario, storage capacity is being built in all the regions, but the system prefers to store electricity close to the load centers rather than in the generating regions (Figure 4.10). In the western and central regions, storage capacities have daily cycles supporting PV generation. On the contrary, in regions such as Hokkaido and Tohoku that export most of their wind generation, storage tends to have a higher number of cycles over the year to compensate for the higher variability of wind generation and to increase the utilization of transmission grid capacity (Figure 4.7).



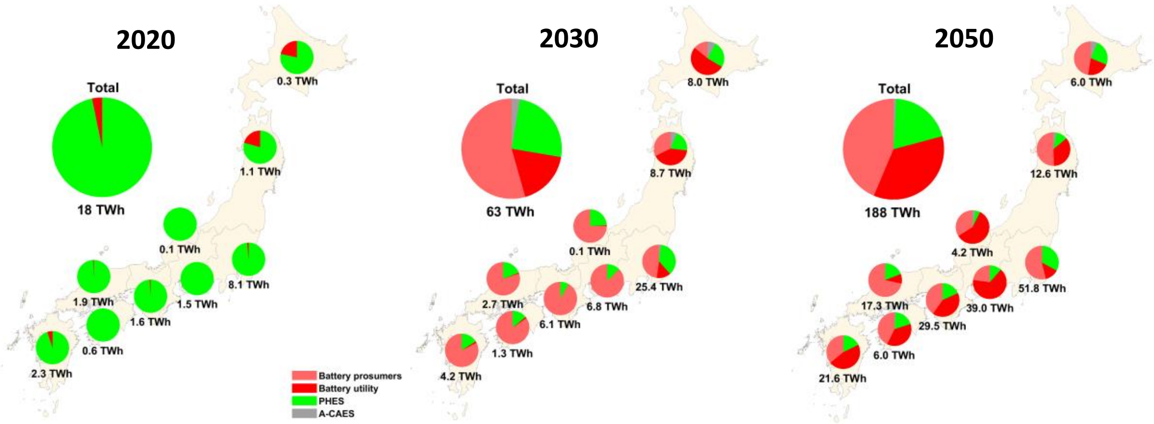


Figure 4.10: BPS all import – regional electricity storage capacities (top) and annual throughput (bottom) in 2020, 2030 and 2050.

For heat, seasonal imports of synthetic fuels in this scenario reduce the need of thermal energy and synthetic gas storage capacity to balance heat supply and for peak shaving. The installed heat storage capacity remains low, increasing gradually from zero in 2020 to 0.27 TWh in 2045, then almost doubling in 2050 to store synthetic methane for industrial use that replaces fossil gas (Figure 4.11, left). Heat storage output stays at a maximum of 50 TWh_{th} until 2045, while it increases by 5 times in 2050, synthetic methane storage accounting for about 75% of it in 2050 (Figure 4.11, right).

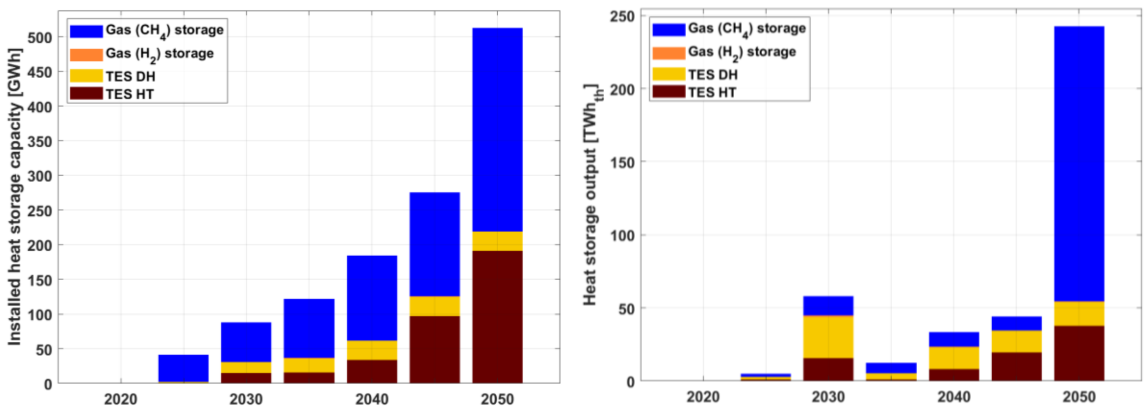


Figure 4.11: BPS all import – evolution of installed heat storage capacity (left) and heat storage output (right) from 2020 to 2050.

Low temperature heat storage capacity is directly linked to low temperature industrial heat demand, space and domestic water heating demand, while high temperature TES and methane storage are linked to the industrial heat demand. Both low and high temperature thermal energy storage (TES) play an important role during the whole transition in providing flexibility to heat supply. While heat storage is mostly used as a buffer for peak heat demand shaving with high cycles over the year, methane storage is used as a storage for bio-methane in 2025-2045, and as a buffer for e-fuels imports from 2050.

Overall, electricity imports from China and Russia and e-fuels imports from Australia provide additional flexibility to the energy systems integration, allowing the system to decrease the local storage capacity compared to BPS autarky scenario: utility scale battery storage capacity is 10% lower and thermal energy storage capacity about 66% lower, while synthetic gas storage is close to zero, because the seasonality of local production is compensated by imports.

Synthetic fuels

Synthetic fuels start to play a role in 2030, and more significantly starting 2040. Consumption increases to 900 TWh_{th} in 2050, slightly more than in the autarky scenario, of which about 70% of hydrogen (627 TWh or 16 Mt, higher calorific value).[35] Sustainable synthetic methane and FT fuels are mostly imported in this scenario (94% for synthetic methane, 78% for FT fuels) as they are the costliest fuels to make with significant conversion losses.

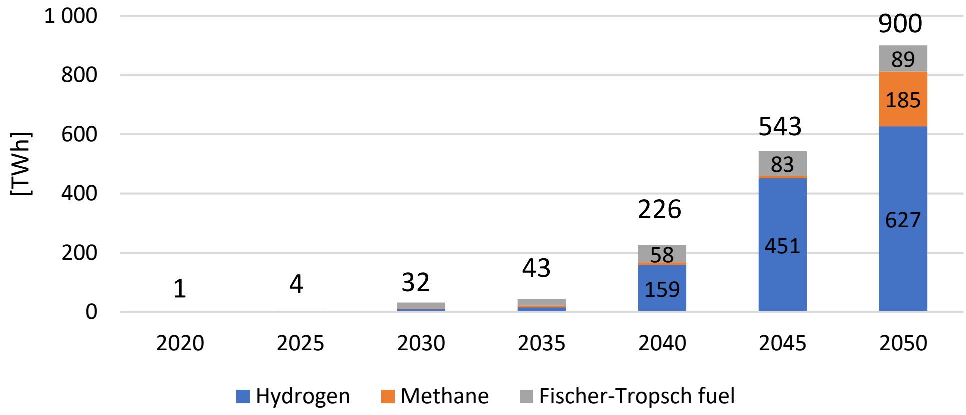


Figure 4.12: BPS all import – evolution of synthetic fuel consumption from 2020 to 2050.

At first, the additional hydrogen demand is expected to be produced through steam reforming, as electrolysis will not yet be competitive and widely available in Japan. Imports of sustainable hydrogen are considered to be available after 2035 in the model. Green hydrogen production is expected to reach 3 TWh in 2030 (~77 000t), up to 68 TWh in 2040 (~2 Mt) and 353 TWh in 2050 (9 Mt), while about the same amount is imported starting 2040. Most of the hydrogen demand is expected to stem from the industry, as gas and coal used to produce high and medium temperature heat are replaced. It is noteworthy in this context that final energy demand from the industry sector was assumed to decrease by 30% between 2020 and 2050, which is a conservative assumption considering the population decline expected at 20% during the same period and the potential of material circularity being currently increasingly discussed, which could reduce demand for energy-intensive primary materials drastically (up to 75% of steel, 50% of aluminum, and 56% of plastics in the EU by 2050 according to Material Economics)[20]. In any case, hydrogen is not used much for power generation or in the transport sector that favors direct electrification, and hydrogen storage is limited over the transition to buffer hydrogen required for the production chain of synthetic methane and FT-fuels.

[35] Synthetic fuel demand includes intermediate demand, such as hydrogen needed to produce synthetic methane or FT fuels partly only produced to store power, or hydrogen and synthetic methane used for power generation. Consumption only includes final demand for those e-fuels, mostly in the industry and transport sectors.

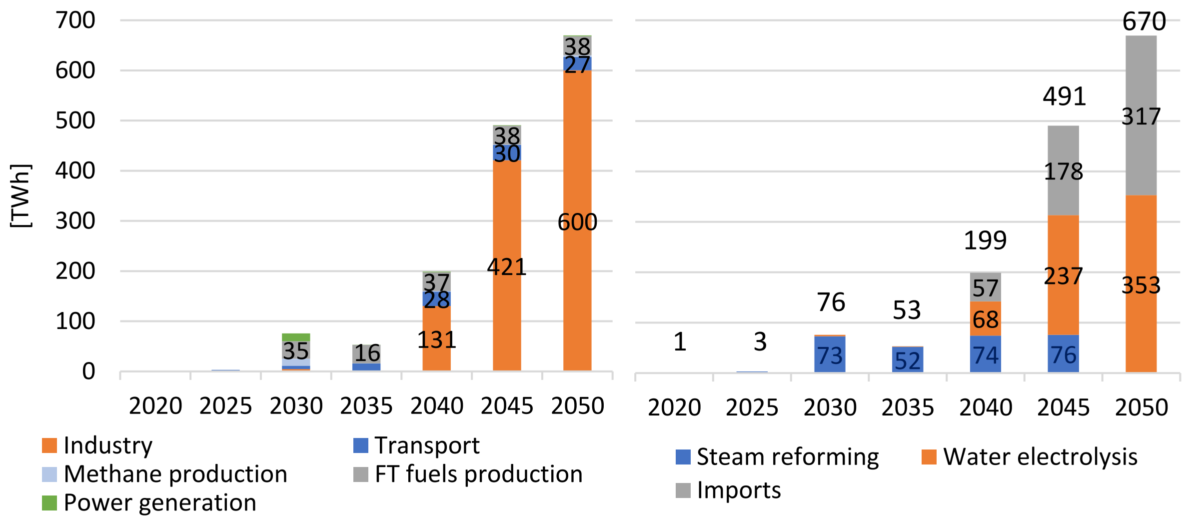


Figure 4.13 BPS all import – evolution of hydrogen demand (left) and supply (right) from 2020 to 2050.

Electrolyzers are an integral part of the synthetic fuels production chain and provide crucial flexibility to the energy system. E-fuels are produced in the model at the consumption site, which explains that there are more electrolyzers in Tokyo, although the installed capacities are relatively well distributed across Japan (except in Shikoku and Hokuriku). A total of around 73 GW_{el} of electrolyzer capacity is needed in 2050 (compared to 197 GW_{el} in the autarky scenario), most of which is built between 2035 and 2045, to cover at least half of the demand in e-fuels in the industrial and transport sectors (Figure 4.14).

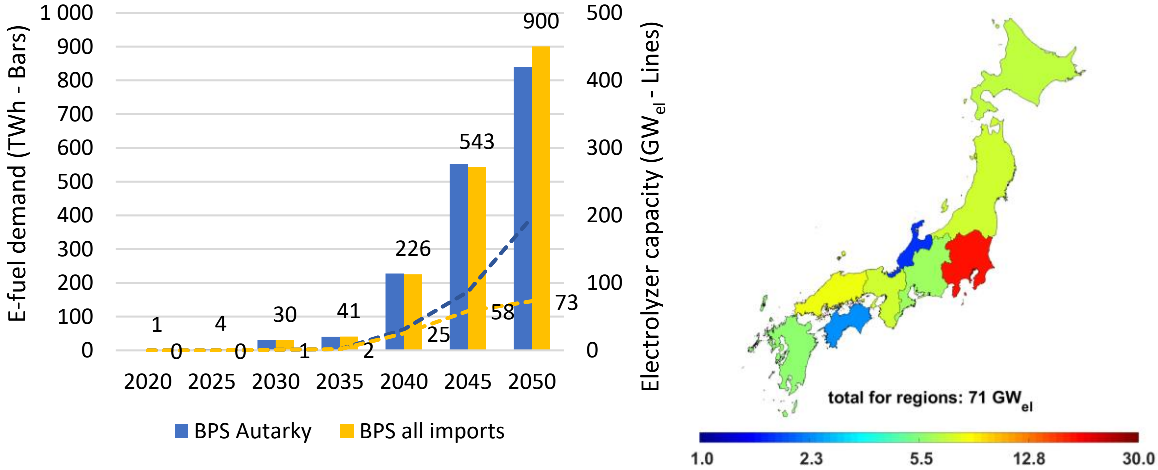


Figure 4.14: BPS all import – comparison of e-fuel consumption and electrolyzer capacity with BPS autarky scenario (left) and regional distribution of electrolyzer capacity in 2050 (right).

4.3. Costs and investments

Annual system costs

The annual system costs represent the yearly average costs of the whole energy system calculated in 5-year intervals. Annual system costs in 2050 are about 30% lower than today. They decline significantly from around 24 700 b¥ (225 b$) in 2020 to about 17 400 b¥ (159 b$) in 2050 after a slight increase in 2030 (Figure 4.13), representing about 3%-4.4% of current GDP.[36] This slight increase in 2030 is due to an increase in investments and CO_2 price in the power sector while the costs in other sectors stagnate. By 2050, imports represent about 26% of the annual system costs. The power and transport sectors transitioning quickly after 2030, reducing their overall costs, the heat sector becomes the main cost driver by 2050. And the transition requiring significant investments into new decarbonized technologies, CAPEX-related energy system costs steadily increase throughout the transition, compensated by the decline of fossil fuel consumption.

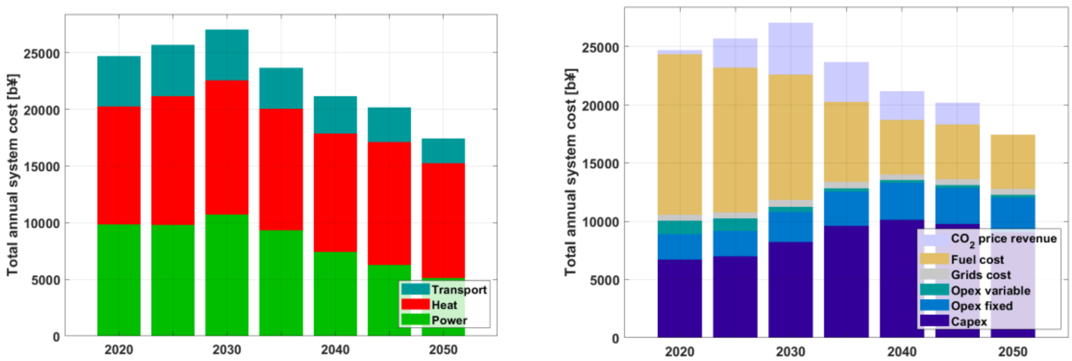


Figure 4.15: BPS all import – total annual system cost per sector (left) and per cost component (right).

The cumulative costs through the transition reach 695 000 b¥ (6 313 b$), including annualized capex, OPEX, fuel costs and CO_2 cost. Note that carbon costs can also be perceived as carbon tax revenue for the state. Without considering carbon costs (which can eventually return to the system in form of RE subsidies or for climate investments), the cumulative cost would be about 10% lower.

Investments are well spread across a range of technologies with most of the investments in the power sector, mostly in solar PV, followed by wind energy (Figure 4.14, right). Yearly capital investment needs increase quickly until 2030 but decrease again quickly after 2040, once the ramp up in renewable energies has been made to cover for the increasing power demand: from 2 000 b¥/year (18 b$/year) in 2021-2025, to nearly 4 700 b¥/year (43 b$/year) in the period 2026-2040, and then back to about 2700 b¥/year (24.5 b$/year) in 2041-2050, representing about 1.4%-3.2% of current gross investment levels.[37] This increase is mostly compensated by a decrease in fossil fuel imports and CO_2 price revenue.

[36] GDP in 2019 in current yens amounted to 561 267 b¥, about 5.1 trillion $. See Cabinet office – Government of Japan, https://www.esri.cao.go.jp/jp/sna/data/data_list/sokuhou/files/2020/qe203_2/pdf/jikei_1.pdf, December 2020

[37] Gross fixed capital formation (GFCF) for 2019 estimated at 146 017 b¥ by the OECD (https://data.oecd.org/gdp/investment-gfcf.htm)

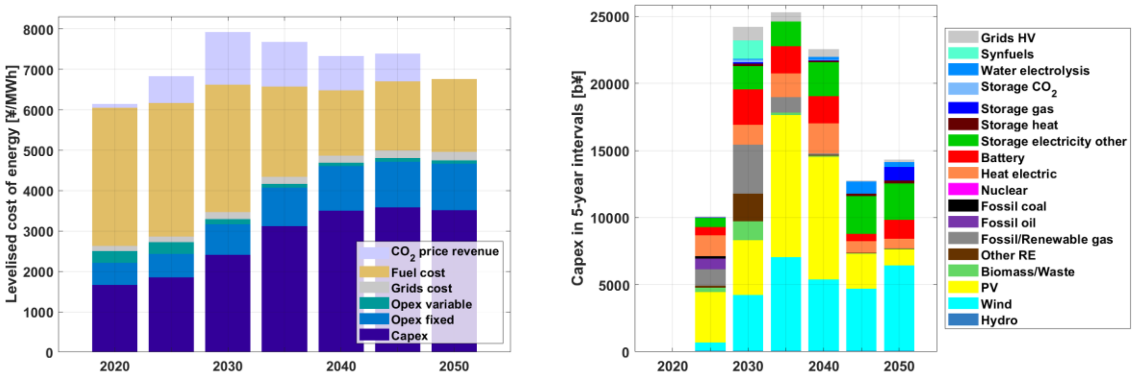


Figure 4.16: BPS all import – evolution of levelized cost of energy (left) and cumulative capital expenditures in five-year intervals (right) from 2020 to 2050.

The levelized cost of energy – the average cost of the energy consumed in the system – is calculated as the total cost of energy production divided by the final energy consumption. It increases by about 30% between 2020 and 2030, from 6 150 ¥/MWh (56 $/MWh) to 7 900 ¥/MWh (72 $/MWh), but decreases afterwards to 6 750 ¥/MWh (61 $/MWh) in 2050 (Figure 4.16, left). The levelized cost of energy is increasingly dominated by capital costs as imported fuel costs continue to decline throughout the transition, which could imply an increased level of energy diversification and self-reliance in Japan.

Levelized cost of electricity

The levelized cost of electricity (LCOE) - average cost of electricity consumed in the system is made up of generation, storage, curtailment and grid costs. It increases from 12 800 ¥/MWh (117 $/MWh) in 2020 to 15 000 ¥/MWh (136 $/MWh) in 2030 due to the accelerated RE introduction and increasing carbon pricing, and later declines by 42% to 8 700 ¥/MWh (79 $/MWh) in 2050 thanks to the integration of low-cost RE generation and reduction of fossil fuel cost to zero (see Figure 4.17, left). From 2035 onwards, over 50% of the LCOE is due to capital expenditures (CAPEX), as fuel costs (including CO_2 pricing) decline through the transition. The share of power import costs remains limited to about 6% of LCOE. Hokkaido has the lowest LCOE in 2050 at around 7 150 ¥/MWh (65 $/MWh), between 13 and 35% lower than in the other regions. The highest average LCOE is found in Shikoku at around 11 000 ¥/MWh (100 $/MWh) by 2050, due to a much lower CF of onshore wind in this region and consequently higher cost of wind energy generation.[38]

[38] The grid reinforcement and development costs were calculated based on the assumption that the grids' NTC limits were going to be relaxed after 2030 for the AC lines, to optimize the use of the interconnections. If the NTC remained at 50% as it is the case today for most of the AC lines, the LCOE would be about 4% higher due to additional grid reinforcement costs.

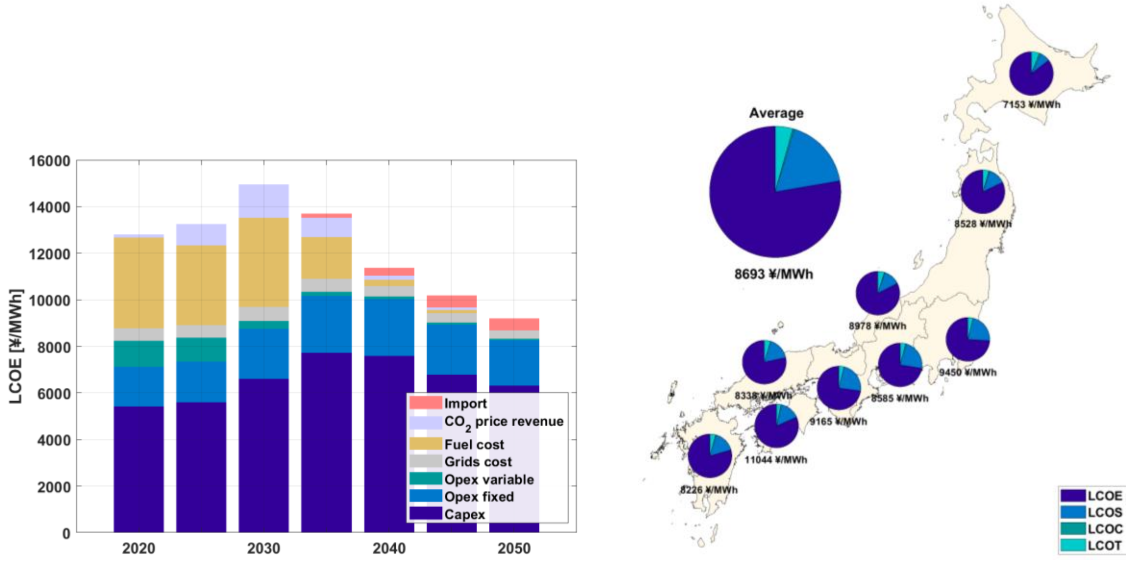


Figure 4.17: BPS all import – levelized cost of electricity per cost component from 2020 to 2050 (left) and per region in 2050 (right)

Levelized cost of heat

The levelized cost of heat (LCOH) is the average cost of heat consumed in the system and consists of generation (including cost of CO_2) and storage costs. Contrary to LCOE, it gradually increases during the transition, from around 4 000 ¥/MWh (37 $/MWh) in 2020 to around 5 800 ¥/MWh (53 $/MWh) in 2050 (Figure 4.18, top left). This is due to the fact that heat demand is driven mainly by industrial process heat, for which the cost increases after 2040 as fossil fuels are switched to e-fuels where heat cannot be electrified (Figure 4.18, bottom left). Space and water heating cost declines steadily over the transition with the further introduction of heat pumps, allowing to electrify 100% of residential and commercial heat demand by 2040, and efficiency gains (Figure 4.18 bottom right).

Similar to LCOE, CAPEX become the largest cost component for heat as fossil fuel use declines over the transition. The investments mainly go towards heat pumps (individual and for industrial processes), but also some electric heating in industry and 2 GW of biomass CHP in 2030 (Figure 4.18, top right). Most of the investments occur in 2026-2030, when the system builds additional gas CHP capacity to substitute coal use in low temperature industrial processes.

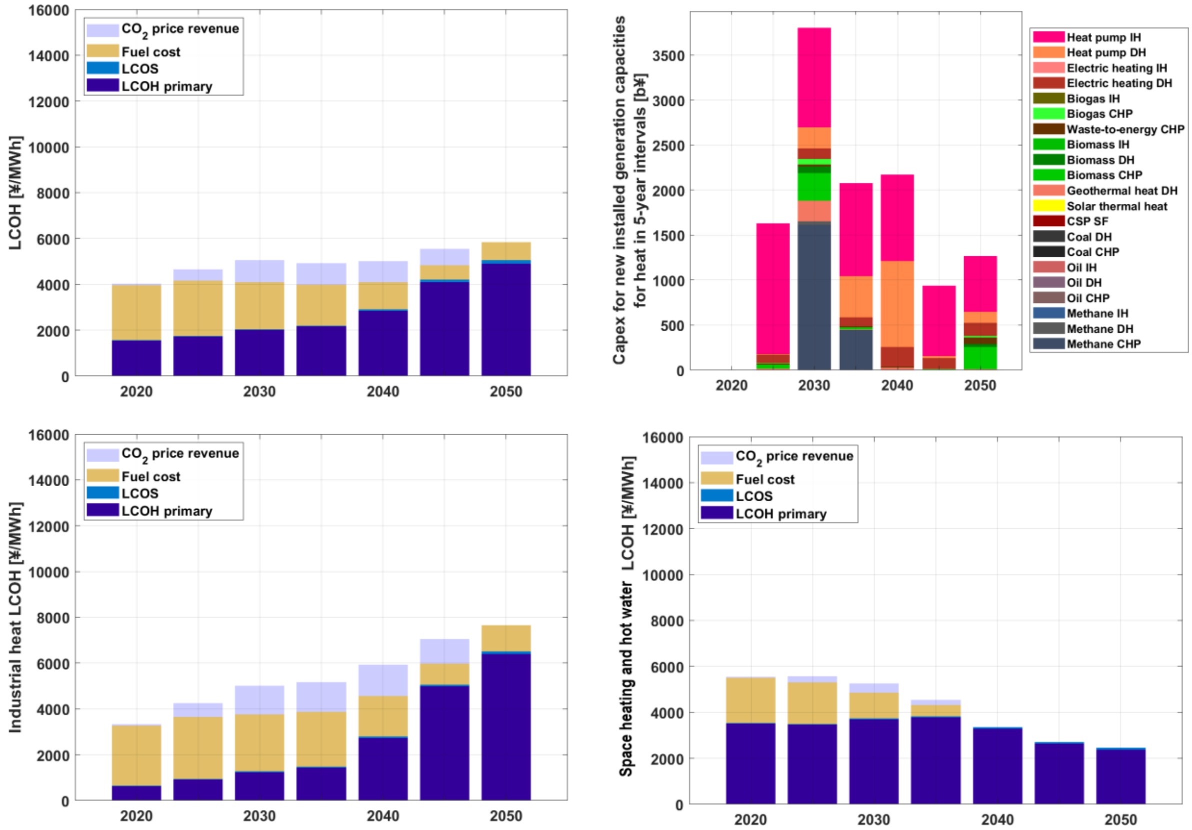


Figure 4.18: BPS all import – evolution of levelized cost of heat (top left), cumulative investment in generation capacities in five-year intervals (top right), LCOH for industry (bottom left) and LCOH for residential and commercial sectors (bottom right) from 2020 to 2050.

However, imports of green e-fuels allow to keep investments and heat cost for industry down. Industrial heat cost increases by 130% to about 8 000 ¥/MWh (73 $/MWh) in 2050, instead of 10 250 ¥/MWh (93 $/MWh) in the BPS scenario, which is compensated by a large decrease in the levelized cost of electricity seen above. This mostly contributes to the overall cost decline between 2040 and 2050. As a result, this import scenario leads to an overall lower levelized cost of energy in the system by 2050. The industrial heat cost increase could be limited to about 7 000 ¥/MWh (64 $/MWh) if hydrogen imports for industry were not capped to a maximum of 50% of demand, as it has been in this scenario. Thus, unlimited e-fuels imports would allow to further decrease LCOH by more than 12% (Figure 4.19).

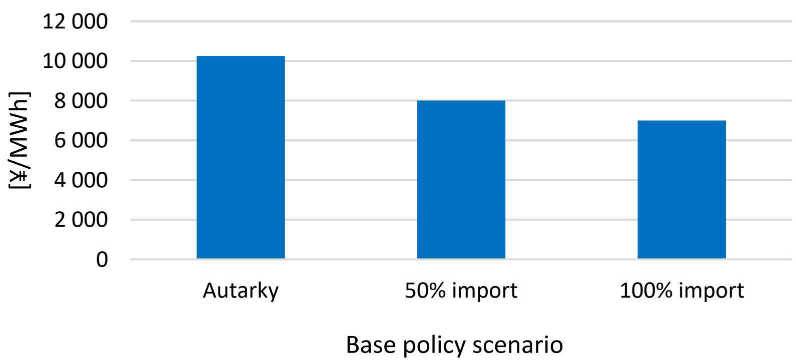


Figure 4.19: Levelized cost of heat in the Base Policy Scenario in various energy dependency settings.

The observed cost decline induced by energy imports comes at the cost of a higher dependence on energy imports and respective exporting regions, and consequently lowers energy security compared to a fully self-sufficient scenario. The share of imports in this scenario would still decline to only 32% from 88% today. Even with unlimited e-fuels imports, the share of local energy supply would be higher than in the current energy system. The optimal balance of energy security and minimization of energy cost requires further investigations and a respective societal discourse.

Cost of synthetic fuels

Even though most of the energy system can be directly electrified, some processes in industry, maritime transport and aviation transport, and the remaining combustion vehicles still require the use of liquid fuels. In order to fully decarbonize the energy system, fossil fuels used in these processes must be substituted by biofuels or synthetic fuels. Due to limited access to sustainable biofuels in Japan and limited scalability of imports, synthetic fuels are expected to provide a notable portion of the fuels required for a complete defossilization of the industry and transport sectors. Yet, the cost of production of sustainable e-fuels expected for Japan by 2050 are significantly higher than the cost of fossil fuels (Figure 4.20, left).

In a power-based energy system, renewable electricity becomes the cheapest energy carrier, with costs comparable to fossil fuels (when including carbon pricing). The cost of e-fuels produced from electricity depends mostly on the overall efficiency of the synthesis processes and partially on their CAPEX. As such, green hydrogen is the cheapest e-fuel and plays a significant role in the industrial sector, while synthetic methane and FT-fuels – that use synthetic hydrogen in their production process – are significantly more expensive due to added equipment costs and higher losses in the synthesis process.

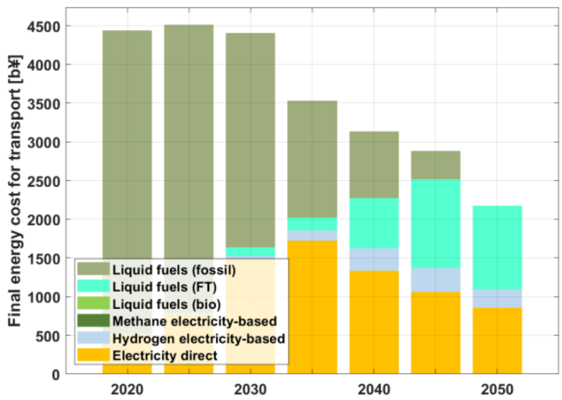


Figure 4.20: BPS all import – evolution of final energy cost for transport per fuel type from 2020 to 2050.

As shown in Figure 4.21, local e-fuel production cost is much higher than the estimated cost of the sustainable e-fuels imports from Australia. In 2050, hydrogen import cost from Australia is estimated at around 6 900 ¥/MWh$_{th}$ (63 \$/MWh$_{th}$), including production cost of about 4 830 ¥/MWh$_{th}$ (44 \$/MWh$_{th}$), transport and transloading costs of 1 800 ¥/MWh$_{th}$ (16.4 \$/MWh$_{th}$) and a 5% margin. This is considerably lower than local hydrogen production cost (11 900 ¥/MWh$_{th}$, 108 \$/MWh$_{th}$).

A similar observation can be made for methane and FT fuels, for which local production can be twice as high as import cost. As a result, no synthetic methane is produced locally in the import scenario except some bio-methane, which price is closer to imported SNG: 11 600 ¥/MWh_{th} (105 \$/MWh_{th}) compared to 9 400 ¥/MWh_{th} (85 \$/MWh_{th}) for imported SNG including transport and transloading costs.

The main component of e-fuels cost is the LCOE. A further decrease of investment cost for RE technologies could decrease the gap between local production and imported e-fuel cost.

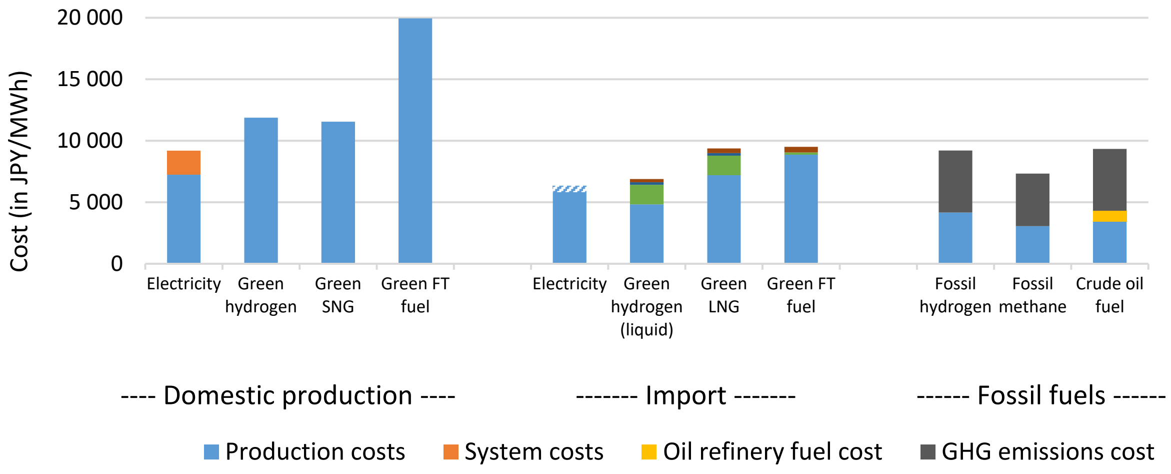


Figure 4.21: BPS all import – local production and import cost of power and e-fuels in 2050.[39]

As seen previously, the use of e-fuels significantly impacts the cost of heat for the industry, but also for the transport sector due to higher e-fuel cost compared to fossil fuels, consequently leading to higher overall energy system cost. Direct electrification remains the most efficient solution where possible, and the use of synthetic fuels should be limited to a minimum.

4.4. Scenario with power import

In this scenario, electricity can be imported from Russia through Hokkaido in the north of Japan, and from China via Korea with an entry point in Chugoku, in the west of Japan. In 2035, 2 GW of grid interconnections were assumed to be available for each route, increasing to 10 GW each in 2045-2050, with a maximum capacity factor of 80% amounting to maximum power imports of 28 TWh_{el} per year starting 2035 and 140 TWh_{el} per year between 2045 and 2050. All other assumptions are same as in the BPS autarky scenario.

This scenario sees an increase in power demand as high as in the BPS autarky scenario with the electrification of all the possible usages (direct and indirect). All the synthetic fuels necessary for the system to decarbonize in the later years of the transition are produced domestically, except for Fischer-Tropsch fuels that are partly imported (up to 70 TWh in 2050). The system imports 26 TWh of power in 2035 (2.5% of demand), and increasingly more to reach 120 TWh in 2050 (6% of demand).

With this level of power imports, the system needs marginally less generation capacities (Figure 4.22 left). That leads to 18% less offshore wind capacity (164 GW) installed by 2050 compared to the BPS autarky scenario, especially in the exporting regions such as Hokkaido, Tohoku and Hokuriku. Solar PV

[39] Power import cost vary depending on entry point (China/Korea or Russia). Domestic SNG includes bio-methane and synthetic methane obtained by methanation, both produced in limited amounts in this scenario. Producing bio-methane being cheaper than SNG produced through methanation, the average is quite low.

and onshore wind both reach their maximum capacity set in this study as they are comparably cheaper than offshore wind.

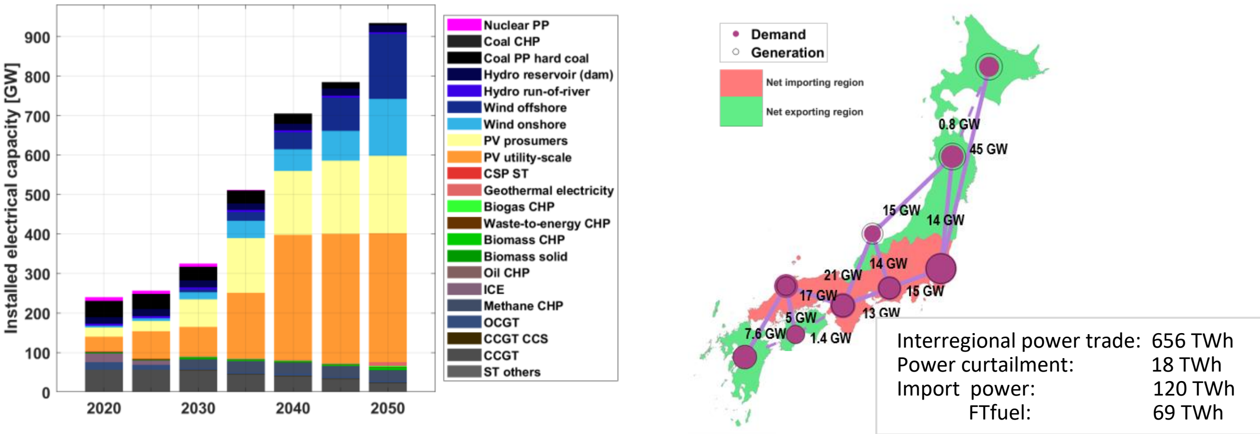


Figure 4.22: BPS power import – installed power generation capacities from 2020 to 2050 (left) and interregional grid capacities and interregional power trade in 2050 (right).

Interregional power trade remains important (see Figure 4.22 right), with a strong reliance on cheaper power generated in the north and south of the country to produce synthetic fuels in the central part of the country. Grids are being built to transport this electricity, but about 30% less is needed over the whole country in this scenario than in the BPS autarky scenario. Power imports from China and Russia also provide an additional source of flexibility to the energy systems integration, allowing the system to decrease the local utility-scale battery capacity by 10%, thermal energy storage by about 5% and synthetic gas storage by about 30%, mostly used as seasonal storage.

Most of the characteristics of the energy system structure and cost otherwise remain the same as in the BPS autarky scenario.

The results of the energy import scenarios show that sustainable electricity and e-fuel imports have benefits for the energy system. Those imports, if available in sufficient amounts and reasonable costs, make it possible to avoid the most expensive energy generation sources and decreases the need for costly energy storage and grid expansion. Imports can additionally decrease the cost of energy supply. Imports of electricity have negligible impact on the levelized cost of energy in this study, due to the relatively small cost difference between imported and domestic electricity and the limited amounts of imports in relation to total electricity generation. Imports of e-fuels have the highest impact on the heat and transport costs, so on the levelized cost of energy due to a higher cost difference between imports and local generation, in addition to the quantity of e-fuels imported. Without the 50% cap on e-fuel imports, the energy cost would be even lower.

5. Delayed Policy Scenario

In this scenario, the Japanese energy system is decarbonized and almost self-sufficient by 2050 but following a pathway that transforms more slowly than the BPS scenario: existing fossil fuel capacities (coal and gas) are politically supported in the system until 2045 in order to maximize the earnings of past investments. Carbon pricing remains lower, and renewables are being deployed later, although they cover a minimum of 30% of power generation in 2030. This pathway also leads to a sharp electrification of heat and transport, resulting in a strong electricity demand growth. In addition, renewable electricity emerges as the prime energy carrier from 2035, though the DPS scenario does not reach a 100% renewable generation by 2050, as a few nuclear power plants are still in service.

5.1. General outlook

GHG emissions decline in this scenario to reach net zero emissions in the energy-related sectors in 2050, but the largest efforts are made after 2030 (Figure 5.1).[40] Emissions decline by 2030 only by 18% relative to 2020 levels, half as much as in the BPS scenario. This corresponds to a reduction of 32% below 2013 levels, which allows this scenario to fulfil the NDC target for 2030. However, the 1.5°C scenario target is not achieved. GHG emissions in the energy-related sectors in the DPS are 35% higher than in the BPS scenario in 2030 and 93% in 2040. The cumulative GHG emissions from 2020 to 2050 are around 18.6 $GtCO_{2eq}$, which is 30% higher than in the BPS scenario.

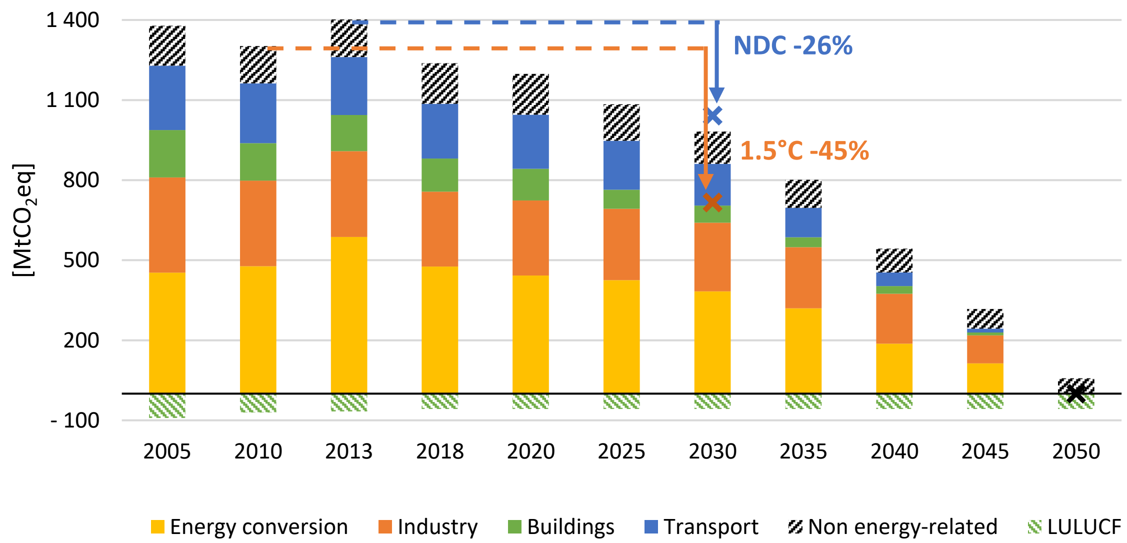


Figure 5.1: DPS - evolution of energy-related GHG emissions per sector and current climate targets.

The building sector is the quickest sector to decarbonize as in the BPS scenario, its emissions halved between 2020 and 2030, and cut by 91% by 2045. The transport sector decarbonizes at a slower pace,

[40] The GHG emissions until 2018 are historical data from the National Greenhouse Gas Inventory Report of Japan 2020 published in the UNFCCC format. The 2018 values for non-energy related emissions and carbon sinks through LULUCF are prolonged as a reference for the year 2020, and are shown to decline linearly after that to reach the level of the carbon sinks so that Japan reaches net zero emissions in all sectors by 2050.

achieving an emissions reduction of 23% between 2020 and 2030, and 93% by 2045. The energy conversion sector, an important sector considering the increasing electrification of energy uses, and the industry sector is the slowest to decarbonize: -13% and -9% of GHG emissions between 2020 and 2030, and -74% and -63% respectively by 2045, leaving significant residual emissions to be abated during the last years of the transition.

As in the BPS scenario, electrification and defossilization of the energy system leads to a massive gain in energy efficiency, lowering primary energy demand (PED) significantly (Figure 5.2). Efficiency improvements on the demand side (mostly due to the electrification of the transport sector and increased motor efficiency) lead to a 15% decline in PED, and efficiency improvements on the supply side (mainly due to renewable-based electrification of low and mid temperature heat (heat pumps)) to a further decline by 13%. PED decreases by 48% (compared to 50% in BPS), from about 4 600 TWh in 2020 to about 2 400 TWh in 2050, as renewable electricity replaces fossil fuels. The difference lies in the transitional years, during which PED in the DPS scenario decreases at a lower rate, about 5 to 10 years later than in BPS, leading to a higher cumulative PED of about 11%. The 2% difference in 2050 originates from the transport sector, which is less electrified in DPS. Without taking into account renewables-based electrification, the primary energy demand would decrease only to about 3 700 TWh in 2050 (Figure 5.2. right), confirming the effectiveness of electrification and defossilization in a decarbonization strategy.

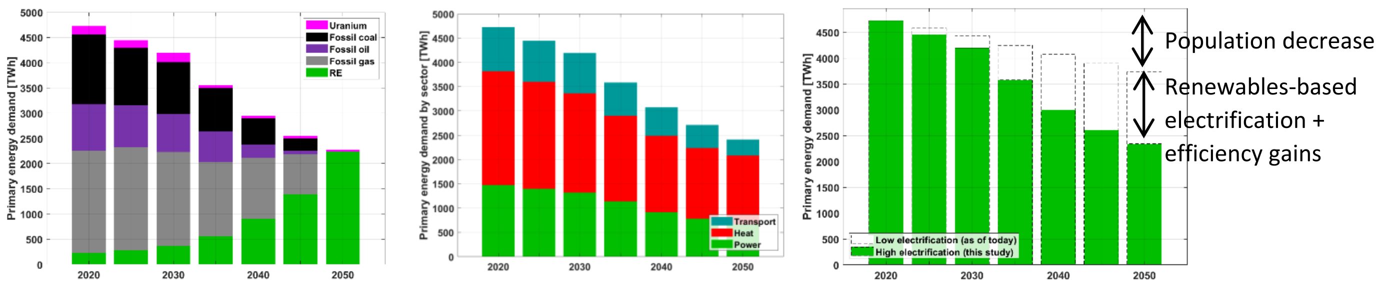


Figure 5.2: DPS – evolution of primary energy demand per energy carrier (left), per sector (middle), and efficiency gain in primary energy demand (right) from 2020 to 2050.

The following sections will analyze the energy transition pathway for each sector, at national and regional levels.

5.2. Energy supply and storage

Power

The electrification and defossilization of the energy system leads to a substantial increase in power demand and installed generation capacities (see Figure 5.3) by 2050. Power generation increases by 2.2 times, while total installed capacity almost quadruples from around 240 GW in 2020 to about 938 GW in 2050, both slightly less than in BPS. Wind and solar generation capacities represents 91% of the total, slightly higher than in the BPS scenario. Power generation is covered to 99.2% by RE, up from 18% in 2020, the remaining by nuclear power.

The electrification-based decarbonization follows a 3 stage-process in this scenario:

- 2020-2030: stagnation of electricity generation
- 2030-2040: gradual increase of electricity generation (+1.8% on average per year), as new uses are starting to electrify, and renewables pursue their expansion
- 2040-2050 (+ 6.2% on average p.a.): sharp acceleration of electricity generation, as electrification is generalized in the transport and heating sectors and synthetic fuels are needed in vast amounts for the hard-to-electrify and hard-to-abate industry sectors.

The continuous support for coal and the commissioning of additional nuclear capacities in the 2030s delay the deployment of renewables by about 5 years and reduce the role of fossil gas compared to the BPS scenario, although existing gas power plants also are supported to avoid stranded assets. In total, only 7 GW of additional gas CHP power plants are being built (73% less than in BPS). Both coal and gas existing capacities are run at their minimum enforced capacity factor after 2035 when renewables become significantly cheaper and cause the phase down of the conventional capacities.

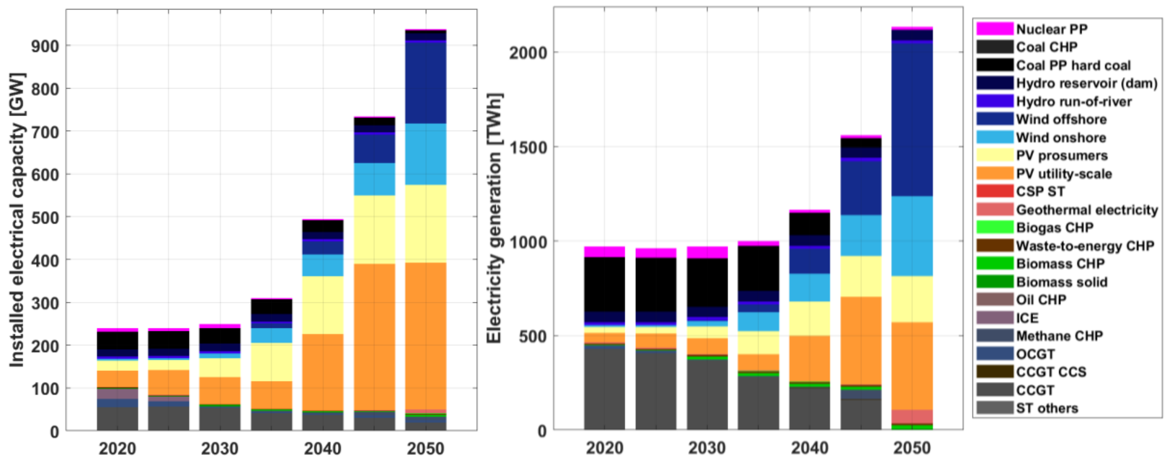


Figure 5.3: DPS – evolution of installed power generation capacity (left) and electricity generation (right) from 2020 to 2050.

By 2050, solar PV and onshore wind reach their maximum capacity set in this study (524 GW and 144 GW respectively), while offshore wind is installed at almost the same level as in the BPS scenario (188 GW). As RE capacities are being installed later than in the BPS scenario, the largest efforts have to be made during the later years of the transition. Between 2021 and 2030, the installed capacities increase annually by 4.1 GW for solar PV, 0.7 GW for onshore wind and only 0.1 GW for offshore wind. Between 2031 and 2050, about 22 GW of solar PV, 7 GW of onshore wind, and 9 GW of offshore wind is installed per year. The fast growth in wind installations occurs during the last step in 2046-2050, with about 14 GW of onshore wind, and 24 GW of offshore wind per year.

The regional distribution of renewable capacities is similar in this scenario as in the BPS scenario: solar PV capacities are well spread across the country, representing most of the installed capacities in the western and central regions. The vast majority (76%) of onshore wind are built in Hokkaido and Tohoku, the 2 northern regions with comparably low population density and high wind potential, while offshore wind mostly in the eastern regions (in decreasing order Tokyo, Tohoku, Hokkaido, and Hokuriku) but also in Kyushu. Only Hokkaido installs marginally less offshore capacity (since from a system perspective it is most costly to develop wind offshore in Hokkaido, as it also requires a significant reinforcement of the grid infrastructure towards the rest of Japan). There is no notable variation in the distribution of conventional capacities.

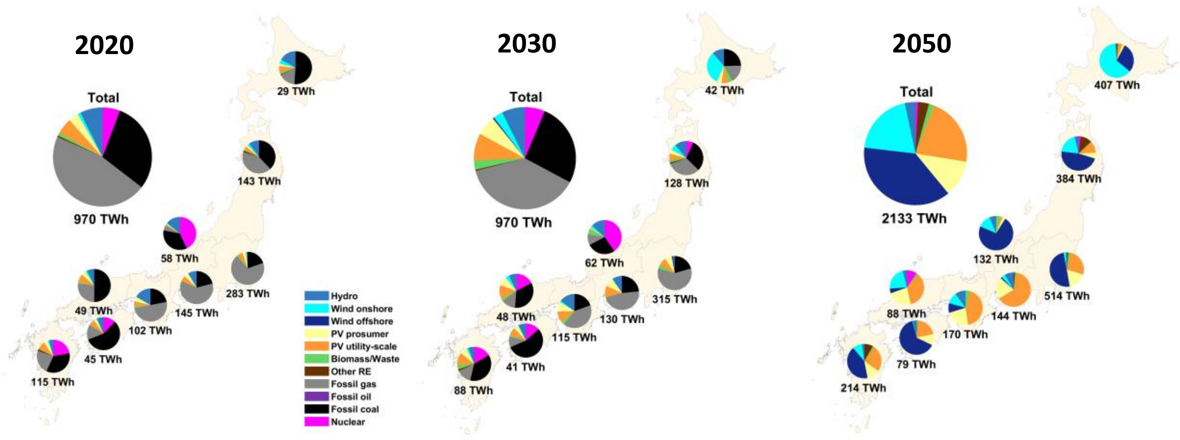


Figure 5.4: DPS – regional electricity generation in 2020, 2030, and 2050.

Power generation also looks similar in both scenarios in 2050, but discrepancies can be seen during the transitional years, since total power consumption increases more slowly in the DPS scenario due to slower electrification. In 2030, power consumption of the DPS scenario is exactly the same as in 2020, and 40% of total power is supplied by gas power plants, 25% by coal power plants, and 6% by nuclear power plants. In 2040, renewable capacities have increased enough to supply 69% of all power generation, the rest split between gas (19%), coal (11%) and nuclear power (1.5%). Renewable power generation and defossilization of the power sector accelerate during the last 10 years of the transition in parallel with electrification of transport and heat demand. As a result, power consumption increases by 80% between 2040 and 2050. In comparison, the BPS scenario integrates renewables earlier, has more gas power generation (with a temporary increase to 60% of total generated electricity in 2030) and no coal or nuclear power starting 2030. This results in substantially higher GHG emissions in the DPS scenario over the transition, resulting in 30% higher cumulative GHG emissions than in the BPS scenario.

Similar to the BPS scenario, interregional power trade becomes important, providing additional flexibility to the system: about 31% (670 TWh) of the generated electricity is traded in 2050, up from 133 TWh in 2020 (Figure 5.5). Hokkaido is exporting the most, with about 68% of its total generation (278 TWh), followed by Tohoku with 194 TWh (51% of its generation) and Hokuriku with 68 TWh (52% of its generation). Tokyo imports the most with 170 TWh (25% of its demand), followed by Chugoku with 145 TWh (63% of its demand), Kansai with 124 TWh (42% of its demand) and Chubu with 89 TWh (38% of its demand).

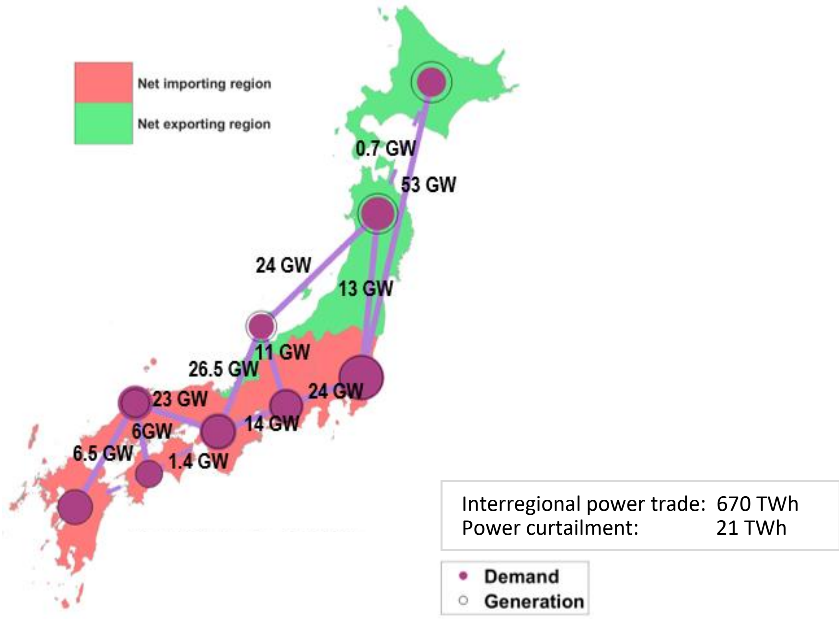


Figure 5.5: DPS – installed interregional grid capacities and interregional power trade in 2050.

Similar to the BPS scenario, most of the grid capacities are built to connect the windy regions in the east with the central and western regions. Grid connections between Hokkaido and Tokyo reach 53 GW capacity, slightly less than in BPS (60 GW). The interconnections between the 50Hz and 60Hz zones is increased to 48 GW, more than in the BPS autarky scenario that goes up to 42 GW. The connections Hokuriku-Kansai, Chubu-Kansai, Kansai-Chugoku, and Chugoku-Kyushu are also reinforced to enable east-west wind energy transfer across the country. In 2020, the grids are used according to existing NTC limits, that are rather restrictive. We have considered that the NTC limits are relaxed after 2030, leading to a relative decrease in the cost of the interregional interconnection reinforcements (with grids utilization capacity factor (CF) limited to 80%). For most of the AC lines, the average capacity factor stays below 50%. The CF for the Chubu-Kansai and Kansai-Chugoku lines reach 70% in 2050 – which remains lower than in the BPS autarky scenario.

Heat

Similar effects as in the BPS heat sector are also observed in the DPS scenario but delayed. Due to lower carbon pricing, the electrification rate is lower and fossil fuels play a significant role in individual and industrial heat supply longer than in the BPS. Though most of the individual heat supply is electrified, fossil gas is still used in individual heating in the early 2040s, while in the BPS scenario the individual heating is fully electrified by 2040. In the industrial sector, some coal is still used until 2045 for heat generation, while coal was substituted by fossil methane by 2040 in the BPS scenario. By 2050, all the fossil fuels are substituted by direct electrical heating, heat pumps or e-fuels and the 2050 system structure and generation mix is the same as in the BPS case (Figure 5.6).

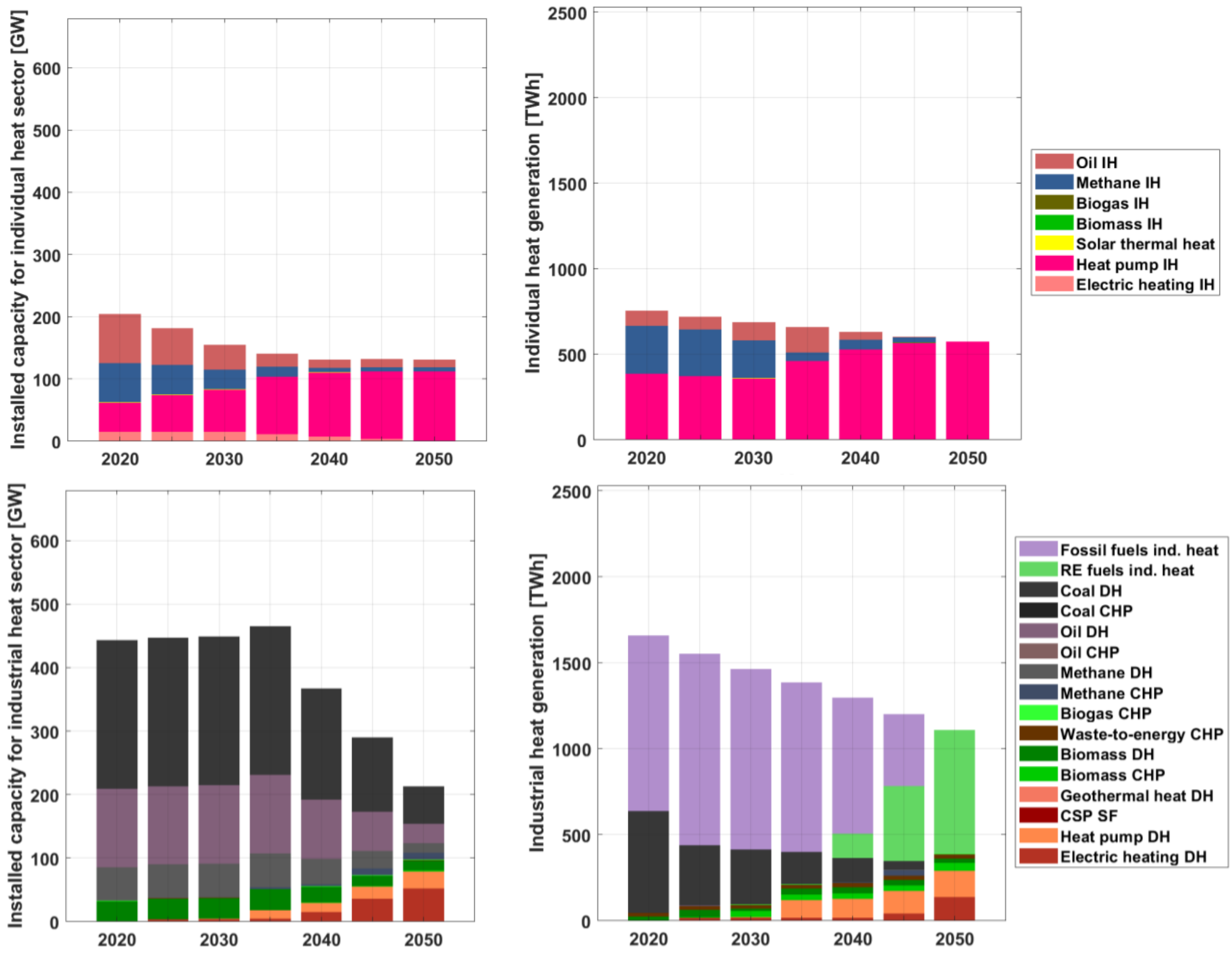


Figure 5.6: DPS – individual heat installed capacity (top left) and heat generation (top right), industrial heat installed capacity (bottom left) and heat generation (bottom right) during the energy transition from 2020 to 2050.

Transport

Final energy demand for transport declines significantly from around 880 TWh in 2020 to about 280 TWh in 2050 (from 22% to 10% of TFED), driven mainly by increasing electrification rates and efficiency gains in road transport, though the transition starts only after 2030 (Figure 5.7). Also, efficiency gains in this scenario are not as significant as in the BPS scenario, as higher shares of internal combustion engine (ICE) vehicles remain in the mix. As such, about half of TFED (159 TWh_{th}) is needed as FT fuels in 2050, of which 134 TWh_{th} are imported, almost twice as much as in the BPS scenario. Similar to the BPS scenario, about 9% of all electricity generation is required for direct electrification of transport and the local production of e-fuels in the transport sector in 2050.

Because of the lower share of electric vehicles (EV) in this scenario, less flexibility is provided by smart charging and vehicle-to-grid technologies. Direct electrification of transport covers about 7% of final energy demand in transport in 2030 and about 32% in 2050. This corresponds to 4.9 million EV in 2030 and 32 million in 2050 (compared to about 1 million today). Together with additional local production and imports of e-fuels, this results in additional costs for the energy system.

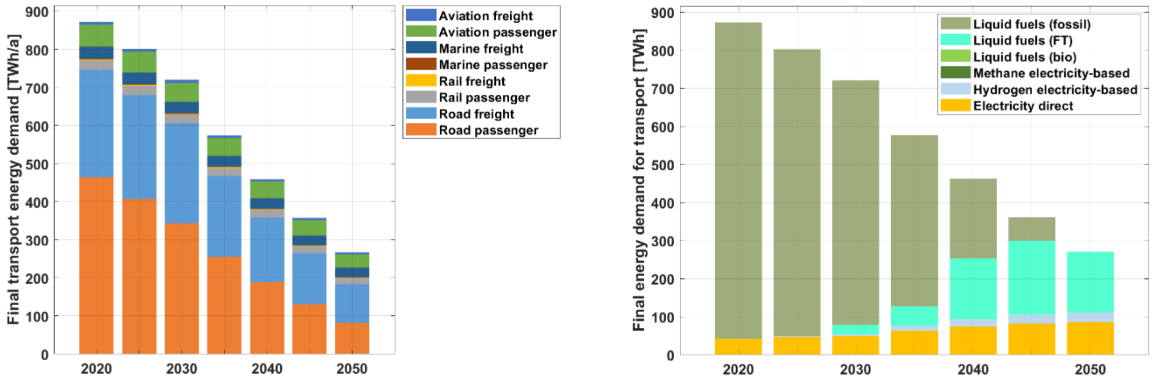


Figure 5.7: DPS – evolution of final energy demand for transport by mode (left) and by fuel type (right) from 2020 to 2050.

Energy storage

As the shares of solar PV and wind increase significantly from 2030 onwards, the role of electricity storage becomes more important in providing continuous energy supply. Similar observations can be made for this scenario as in the BPS scenario: electricity storage capacity increases significantly as well as the output (Figure 5.8). As fewer electric vehicles are in the road transport mix, V2G services contributes less to system flexibility, leading to more utility-scale batteries being installed here. Due to added flexibility from a longer use of conventional power plants and lower shares of renewable energy in the system, the deployment of electricity storage also happens with about 5 years delay. A-CAES similarly plays a limited role while the use of PHES decreases even more at the end of the transition in this scenario, as more modern battery storage technologies with lower losses are available in the system.

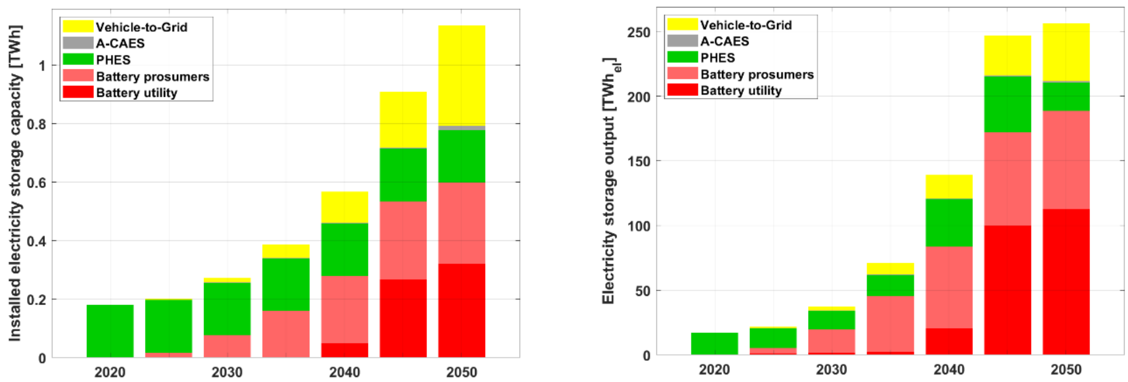


Figure 5.8: DPS – evolution of installed electricity storage capacity (left) and electricity storage output (right) from 2020 to 2050.

As in the BPS scenario, storage capacity is being built in all the regions, but the system prefers to store electricity close to the load centers rather than in the generating regions (Figure 5.9). The regional distribution is even more centered in the densely populated regions such as Tokyo, Chubu and Kansai, where a significant amount of utility storage capacity has to be built to compensate for the lack of V2G services (Figure 5.9).

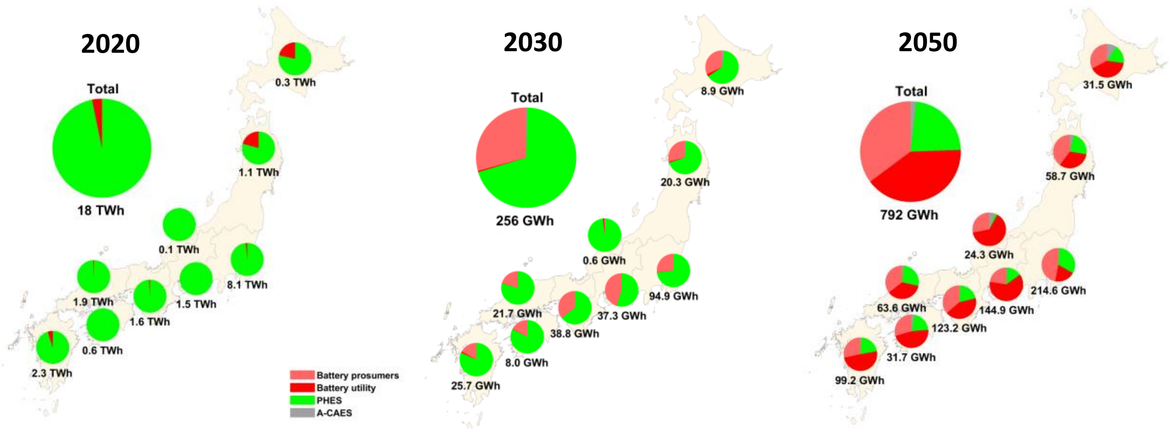


Figure 5.9: DPS – regional electricity storage capacity in 2020 (left), 2030 (center) and 2050 (right).

In the western and central regions, storage capacities have daily cycles supporting PV generation. On the contrary, in regions such as Hokkaido and Tohoku, storage tends to have higher number of cycles over the year to compensate for the higher variability of wind generation and to increase the utilization of transmission grid capacity in those regions that export most of their wind generation.

The deployment of heat storage capacity is the same as in the BPS scenario, with about 100 TWh of seasonal methane storage being installed in 2050 in order to provide synthetic fuels for industrial processes during the periods of low RE generation. The available storage capacity is only being used starting 2040 when fossil fuels are slowly phasing out (Figure 5.10). Heat storage output remains 20% lower than in the BPS scenario in 2050 (244 TWh_{th}), which is explained by a lesser use of both low temperature heat and high temperature thermal energy storage, mostly in the eastern regions (Hokkaido, Tohoku and Tokyo).

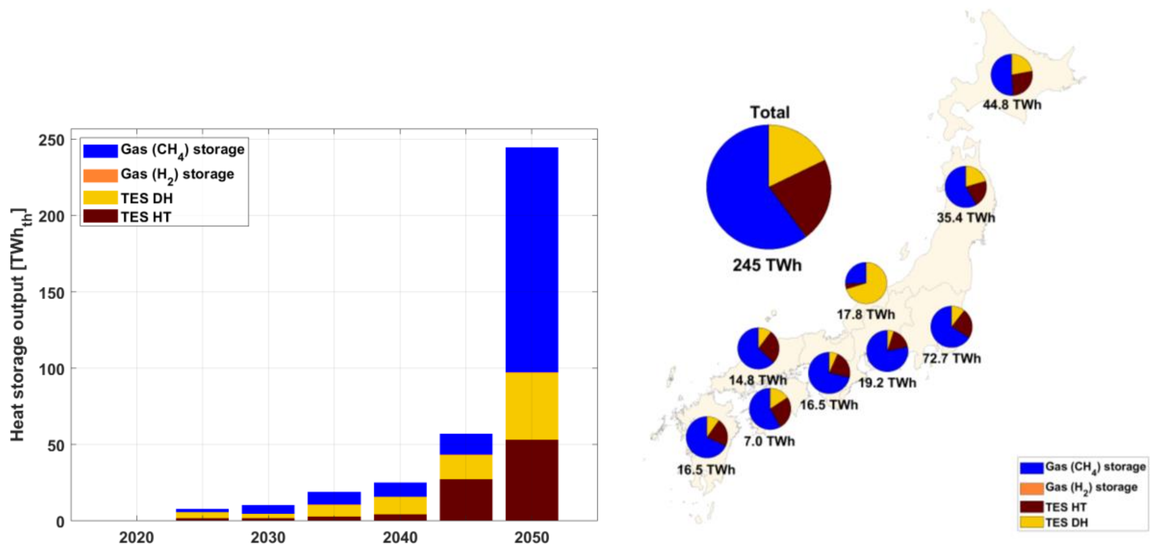


Figure 5.10: DPS – evolution of heat storage output from 2020 to 2050 (left) and regional heat storage output in 2050 (right).

Synthetic fuels

Electrolyzers are an integral part of the synthetic fuel production chain and provide crucial flexibility to the energy system. E-fuels are produced at the consumption site. As such, the highest installed capacity of electrolyzers can be seen in Tokyo. Slightly more electrolyzer capacity is installed in this scenario over the transition compared to the BPS autarky scenario for a total of 199 GW_{el} in 2050. E-fuel demand in the industrial and transport sectors increases to about 906 TWh_{th} in 2050 (about 7% more than in BPS), of which about 66% of hydrogen (602 TWh or 15 Mt, higher calorific value). Hydrogen is not used for storage. The role of hydrogen storage being limited over the transition to buffer hydrogen required for the production chain of synthetic methane and FT-fuels.

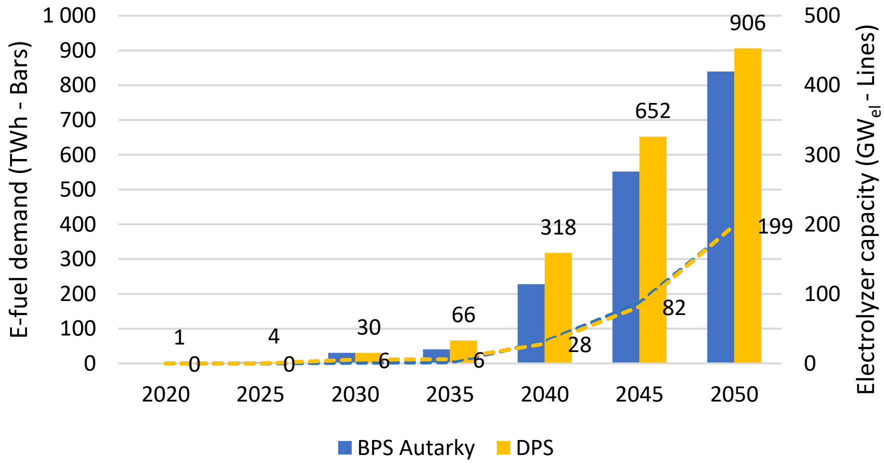


Figure 5.11: Evolution of e-fuel consumption and electrolyzer capacity from 2020 to 2050 in the BPS and DPS autarky scenarios.

5.3. Costs and investments

Annual system costs

The annual system costs represent the yearly average costs of the whole energy system calculated in 5-year intervals. As in the BPS scenario, they decline significantly from around 24 700 b¥ (225 b$) in 2020 to about 21 500 b¥ (196 b$) in 2050 (Figure 5.12), representing about 3.8%-4.4% of current GDP,[41] the cost of fossil fuels being replaced by investment costs over the transition. This transition happening later in this scenario, annual costs are lower than in the BPS scenario between 2020 and 2030, but this trend reverses after 2040.

The total cumulative system cost through the transition is same for the BPS and the DPS, with the costs of carbon representing about 8% of the total. Note that carbon costs can also be perceived as carbon tax revenue for the state. Without considering carbon costs (which can eventually return to the system in form of RE subsidies or for climate investments), the cumulative system costs of the DPS scenario are about 2.3% or 14 400 b¥ (131 b$) higher than in the BPS scenario.

[41] GDP in 2019 in current yens amounted to 561 267 b¥, about 5.1 trillion $. See Cabinet office – Government of Japan, GDP (Expenditure Approach) and Its Components, December 2020

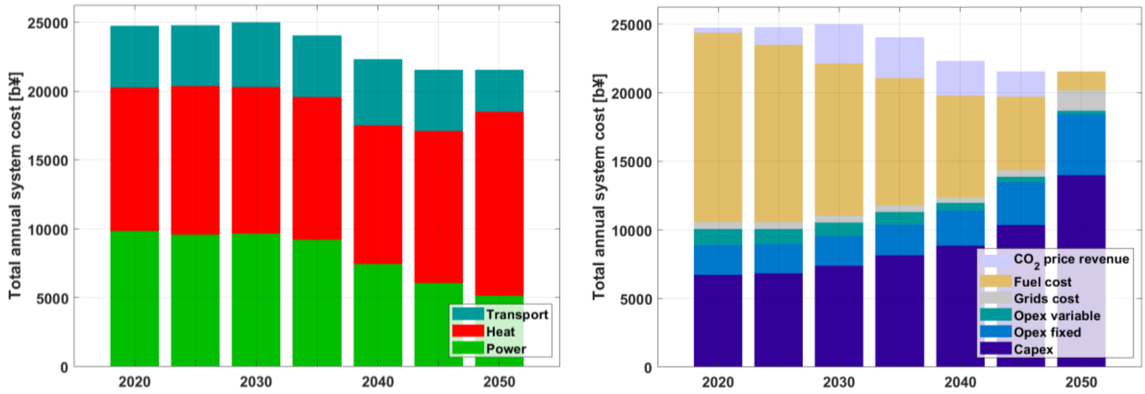


Figure 5.12: DPS – evolution of annual system costs per sector (left) and cost component (right) from 2020 to 2050.

Levelized cost of energy

The levelized cost of energy - calculated as the total cost of energy production divided by the final energy consumption - increases steadily by about 30% over the period, landing at a similar level as in the BPS scenario by 2050 (8 150 ¥/MWh, or 74 $/MWh), an increasing share of it being spent on investments (Figure 5.13). The capital costs are well spread across a range of technologies with the majority of investments in the power sector, mostly in wind energy followed by solar PV. But as electrification and defossilization take place later in this scenario compared to the BPS scenario, yearly capital investment needs increase gradually from 2020 to 2045, from 1 600 b¥/year (14.5 b$/year) in 2021-2025, to nearly 6 800 b¥/year (62 b$/year) in 2041-2045. They peak at 14 500 b¥/year (132 b$/year) in the latest period 2046-2050, 13% higher than in the BPS scenario (13 000 b¥/year (117 b$/year) in 2046-2050), as the remaining fossil fuels in power, heat and transport sectors are being substituted later. This increase in CAPEX is mostly compensated by a decrease in fossil fuel imports and CO_2 costs.

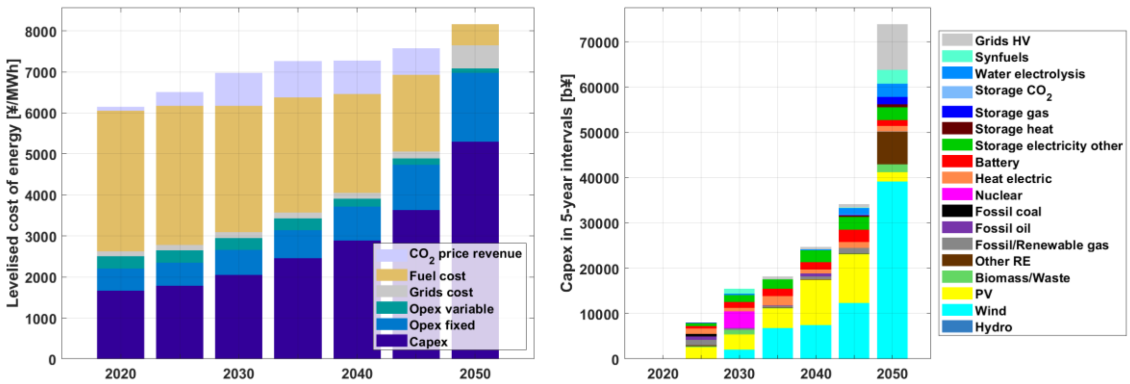


Figure 5.13: DPS – evolution of levelized cost of energy (left) and cumulative capital expenditures in five-year intervals (right) from 2020 to 2050.

Levelized cost of electricity

The levelized cost of electricity (LCOE) – average cost of electricity consumed in the system is made up of generation, storage, curtailment and grid costs. It slightly increases from about 12 800 ¥/MWh (116 $/MWh) in 2020 to 13 500 ¥/MWh (122.5 $/MWh) in 2030 to then decrease by 38% to around 8 400 ¥/MWh (76.5 $/MWh) in 2050 (Figure 5.14). The LCOE increase in the 2030s is much smaller than in the BPS scenarios due to lower RE integration and, most importantly, lower carbon pricing.

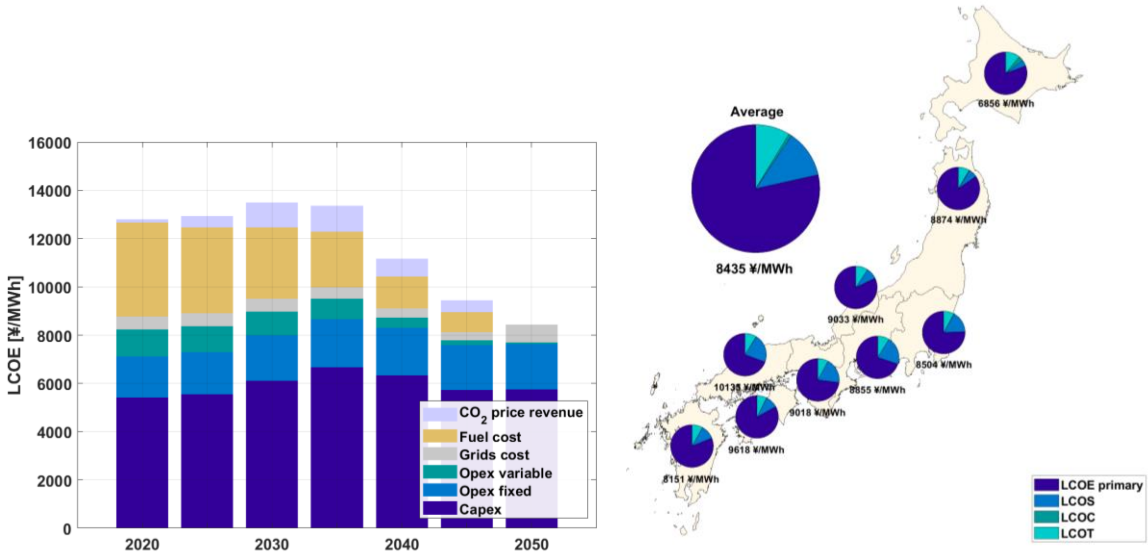


Figure 5.14: DPS – levelized cost of electricity per cost component (left) and region in 2050 (right)

From 2035 onwards, over 50% of the LCOE is due to CAPEX, as fuel costs (including CO_2 pricing) decline through the transition. Same as in the BPS scenario, Hokkaido has the lowest LCOE in 2050 with around 6 850 ¥/MWh (62 $/MWh), between 16 and 33% lower than in the other regions. The highest average LCOE are also found in Chugoku and Shikoku at around 10 100 ¥/MWh (92 $/MWh) and 9 600 ¥/MWh (87 $/MWh) respectively by 2050. In Chugoku, the installed RE capacities reach their upper limit between 2046 and 2050, leading to a stark increase in power imports from other regions, to 63% of demand in 2050. This implies additional grid and storage in order to balance the system, adding up to the costs. The Shikoku region is mostly self-sufficient, but has a generation mix with 64% of offshore wind (Figure 5.4) that has higher costs than PV or onshore wind, leading to additional costs. It remains cheaper to build local generation capacities than to build them elsewhere and build additional grids to transport power.

Levelized cost of heat

The levelized cost of heat (LCOH) – average cost of heat consumed in the system consists of generation (including CO_2 price) and storage costs. Similar to the BPS scenario, the LCOH in the heat sector increases from around 4 000 ¥/MWh (36 $/MWh) in 2020 to about 7 550 ¥/MWh (69 $/MWh) in 2050 (Figure 5.15, top left). This is since heat demand is driven mainly by industrial heat, as its cost grows quickly due to the switch from fossil fuels to e-fuels. Space and water heating cost are halved due to the introduction of efficient heat pumps in the system, but full electrification is only achieved in 2050, contrary to the BPS scenario that already achieves it in 2040 (Figure 5.15, bottom right).

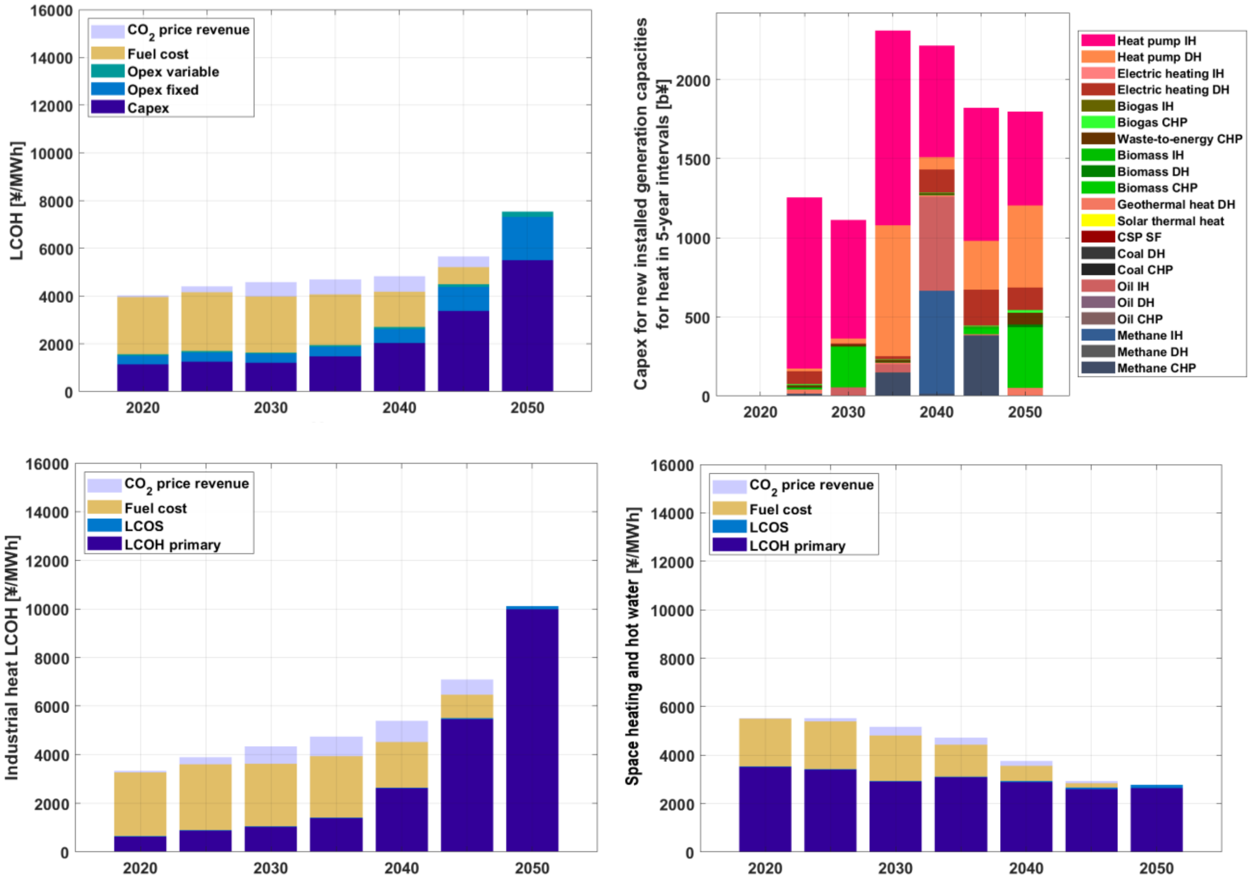


Figure 5.15: DPS – evolution of levelized cost of heat (top left), cumulative investment in generation capacities in five-year intervals (top right), LCOH for industry (bottom left) and LCOH for residential and commercial sectors (bottom right) from 2020 to 2050.

Similar to LCOE in BPS, CAPEX become the largest cost component for heat as fossil fuel use declines over the transition. The investments mainly go towards heat pumps (individual and for industrial heat), but also electric heating in industry and 1.5 GW of biomass CHP plants in 2030, growing to 4.6 GW in 2050 (Figure 3.19, top right). Most of the investments occur in 2031-2040, when a significant part of the oil and gas heating systems reach the end of their technical lifetime. Part of it is simply replaced, part of it substituted by electric heating systems. Hokkaido, Tohoku, Chugoku and Shikoku have the highest average LCOE – Hokkaido and Tohoku due to seasonality of their climate with high peak heat demand in the winter months and higher reliance on the heat storage, Chugoku and Shikoku due to their high cost of electricity.

The delayed defossilization of the energy system prolongs the country's dependence on fossil fuel imports, leading to higher cumulative GHG emissions. Also, the moderate transition in the 2020s leads to an accelerated introduction of renewable energy in the later years, especially in the 2040s, which may be at the edge of what can be managed by the industry and the administration. Including carbon cost, DPS and BPS scenarios have similar levels of cumulative system cost, but the cumulative system cost in the DPS is about 2.3% higher than in the BPS autarky scenario if carbon cost is considered to flow back to the energy system through revenue recycling into the energy transition.

6. Demand sensitivity

A decrease of about 35% in final energy consumption by 2050 was assumed in the reference demand level used in all the scenarios above. However, the impact of population decline and efficiency improvements on the level of energy consumption can be higher. To quantify the effect of a faster and steeper final energy consumption decrease on the energy system transition, variants of the BPS autarky scenario were modelled with 10% (Low10), and 20% (Low20) lower final consumption in 2050, all other things being equal. As such, final energy consumption was assumed to decrease linearly between 2020 and 2050, the starting level in 2020 being the same in all the scenarios.

The BPS autarky scenario shows that domestic RE resources are sufficient to reach a full defossilized and almost self-sufficient energy system by 2050. However, it comes at the cost of high utilization of local RE resources, high dependence on grids and electricity exchange between the regions, leading to higher energy costs, especially to defossilize industrial processes. A further decline in final energy demand could allow to release some of these constraints and reach lower cost of energy supply.

6.1. General outlook

A steeper energy consumption reduction does not lead to significant structural changes in the BPS. The transition pathways are similar with standard demand assumptions. The primary energy demand, system cost and GHG emissions decrease proportionally to the final energy consumption, leading to 4-5% and 8-9% lower cumulative GHG emissions and system costs in the BPS_Low10 and BPS_Low20 scenarios, respectively, in comparison to the BPS.

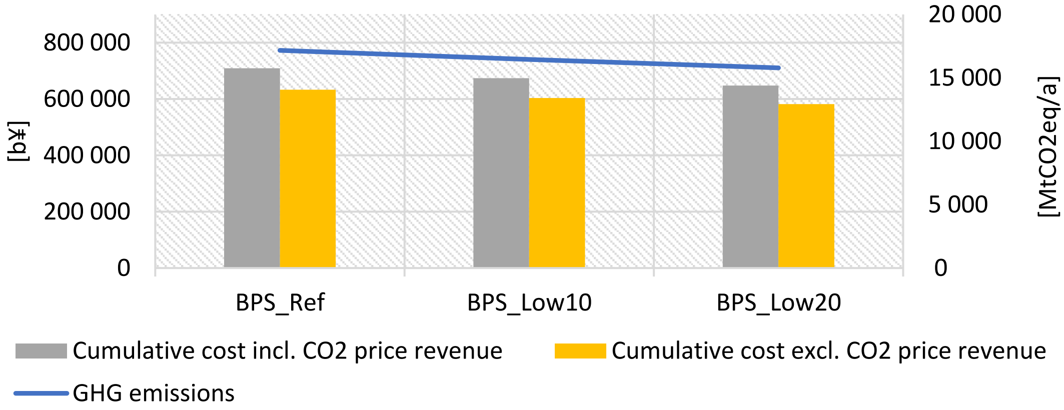


Figure 6.1: Cumulative system cost and GHG emissions in 2050 for the BPS variations.

The highest impact is seen in terms of RE resources utilization and grid reinforcements. In case of lower energy consumption and demand, less offshore wind capacities are installed in the eastern regions, in case of 20% energy consumption reduction scenarios the onshore wind capacity also deceases. A lower demand leads to lower electricity exchange and less grid capacities are sufficient to ensure the system operation. A lower energy demand also results in more localized regional energy systems.

With lower energy demand, less investments in high-cost offshore wind capacities and grid expansion are required, leading to a lower total energy cost in the long-term.

6.2. Lower demand sensitivity analysis – BPS

The impact of energy demand sensitivity on the installed capacity of key RE technologies across the BPS is shown in Figure 6.2. Until 2035, installed capacity of PV, and onshore and offshore wind turbines is same in all BPS variants. Beyond 2035, the overall installed wind capacity declines significantly in the BPS_Low10 and especially in the BPS_Low20, in comparison to the BPS scenario.

In 2050, the total installed capacity of offshore wind decreases by 30% in the BPS_Low10 and 37% in the BPS_Low20, whereas the onshore wind capacity in the BPS_Low10 is on the same level as in the BPS, but decreases by 26% in the BPS_Low20. The offshore wind capacity faces the most significant reduction compared to other main RE technologies due to comparably higher costs. Throughout the transition offshore wind electricity generation is more costly than onshore wind and PV generation.

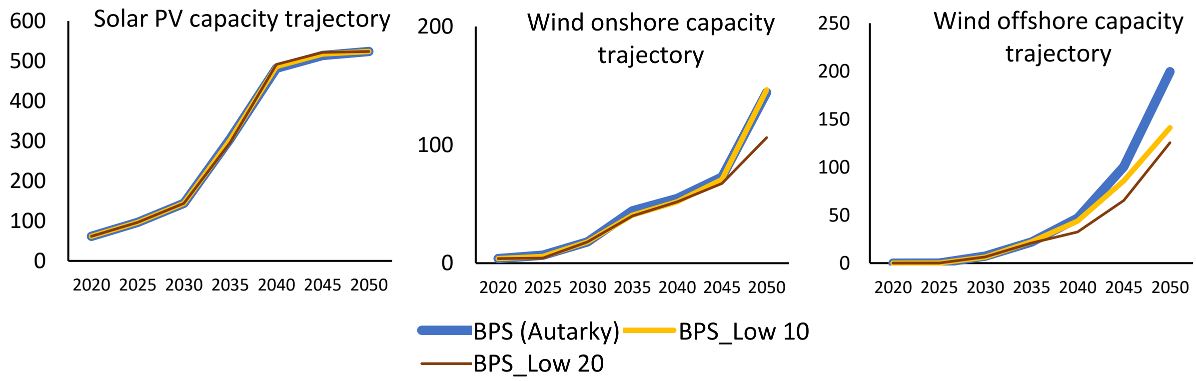
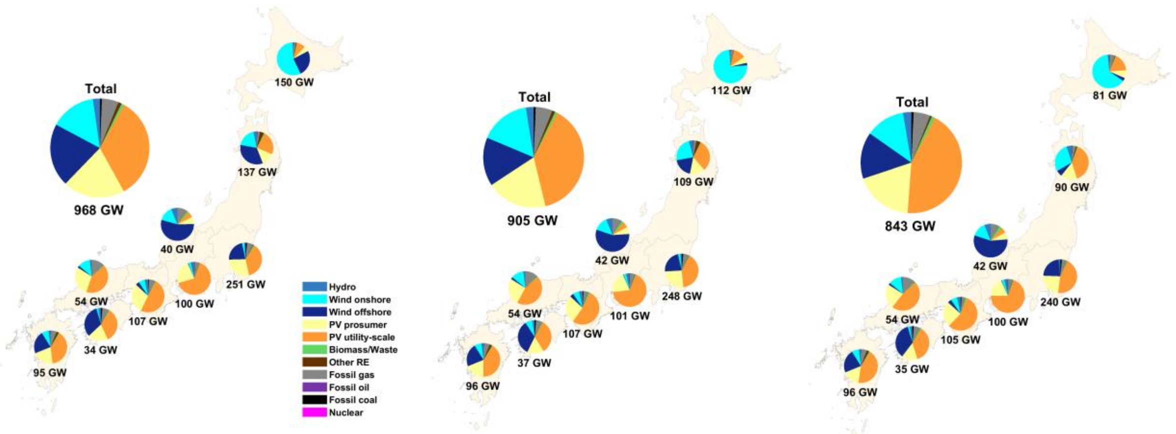


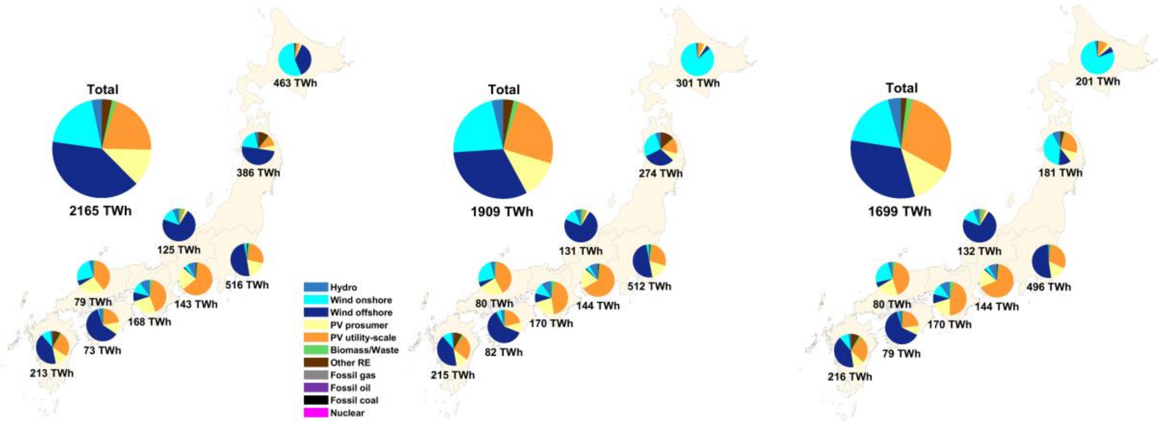
Figure 6.2: Solar PV (left), onshore wind (center) and offshore wind (right) installed capacity throughout the transition in Base Policy Scenario variations.

PV generation becomes the least cost source of electricity in the system and thus demand sensitivity does not have any impact on solar PV deployment through the transition across the BPS variations. Solar PV resources are fully utilized across the scenarios through the transition: installed capacity grows on the same level in all BPS variations reaching 524 GW in 2050. Yet, less prosumer PV is installed as localized power demand declines, which is especially noticeable in BPS Low20 where prosumers represent 30% of all installed PV capacities and generation in 2050 versus 37% in the BPS scenario. This is compensated by more utility-scale PV systems installed (Figure 6.3).

The impact of demand reduction on the electricity generation structure also depends on the region. The onshore and offshore wind generation capacity and electricity output decreases mostly in the RE-rich eastern regions, whereas in the densely populated Central and western regions the electricity generation structure remains the same. In Chubu, Kansai, Chugoku, Kyushu, the maximum capacity set for this study is reached for solar PV, onshore and offshore wind even in the case of the BPS_Low20 scenario (Figure 6.3).



BPS Autarky **BPS_Low10** **BPS_Low20**



BPS Autarky **BPS_Low10** **BPS_Low20**

Figure 6.3: Regional generation capacity (top) and power generation (bottom) in 2050 across the BPS variations.

Total electricity generation decreases proportionally to energy consumption reduction by 12% in the BPS_Low10 and 22% in the BPS_Low20 in comparison to the BPS scenario. Generation decreases slightly more than demand as there are less losses during transportation and storage, as the system become more regional and localized. Indeed, demand reduction leads to a significant drop in the volume of electricity exchanged between the regions (Figure 6.4). Power exchange declines by 34% in the BPS_Low10 and 57% in the BPS_Low20 in comparison to the BPS. All the regions become more self-sufficient and the role of Hokkaido and Tohoku in energy supply decreases significantly. And in the low demand scenarios, Kyushu and Shikoku emerge as the new exporting regions. In the BPS_Low20, the grid operates at a lower capacity factor and maintains a vital functionality in balancing the energy system.

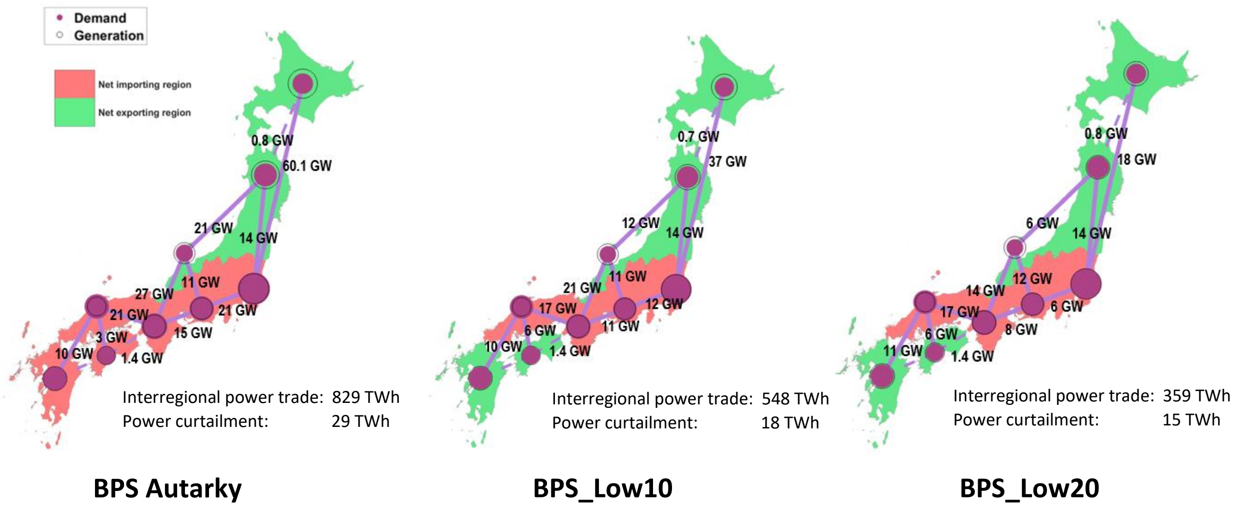


Figure 6.4: Annual interregional electricity exchange in 2050 across the BPS variations.

Following the decrease in prosumer PV capacities, also less prosumer batteries are installed in favor of significantly more utility-scale batteries. Overall, the battery capacity increases with lower demand (about 10% for BPS Low20) while heat storage decreases significantly. In BPS Low20, a third less low and medium temperature thermal energy storage is necessary, almost half as much gas storage, and a quarter less electrolyzers. Low temperature heat storage is directly linked to low temperature industrial heat demand, space and domestic water heating demand, while high temperature TES and methane storage are linked to industrial heat demand. Decreasing demand in sectors that are difficult to electrify, especially medium and high temperature heat for the industry, mostly reduce the need for storage capacities to balance heat demand.

6.3. Impact of demand sensitivity on energy cost

The LCOE for the power sector decreases substantially through the transition across the BPS variations (Figure 6.5 left). The LCOH on the opposite increases substantially with the transition in all the scenarios (Figure 6.5 right). For both costs, lower demand leads to a slight cost advantage in 2050.

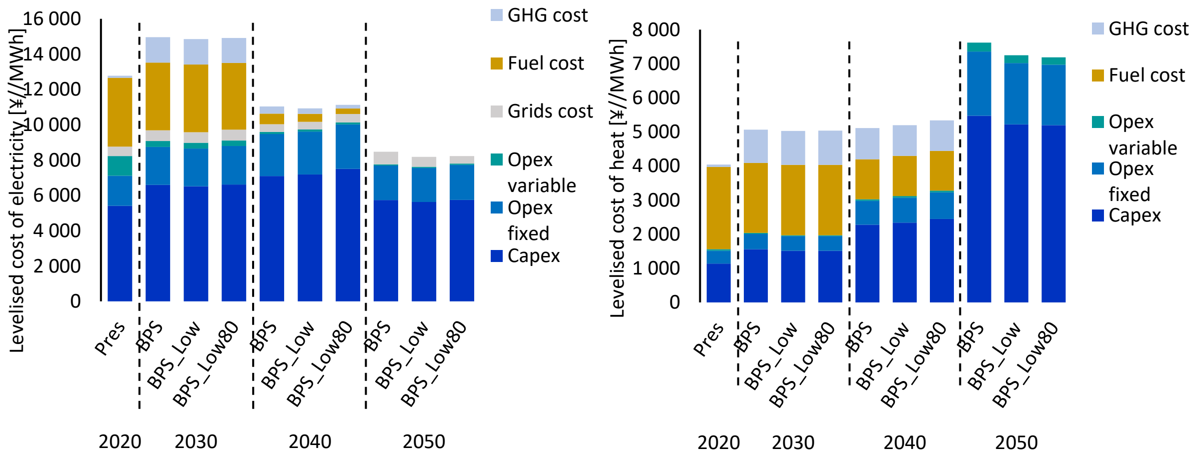


Figure 6.5: Levelized cost of electricity (left) and Levelized cost of heat (right) for the BPS variants.

The levelized cost of energy is a vital determining factor to measure the economic viability of he various energy scenarios. This cost comprises all components of the energy system, including the electricity and heat as primary sources of energy, which are the crucial cost indicators for the energy transition. The levelized cost of energy is by 2050 slightly lower in the lower demand scenarios, though without a significant difference (Figure 6.6).

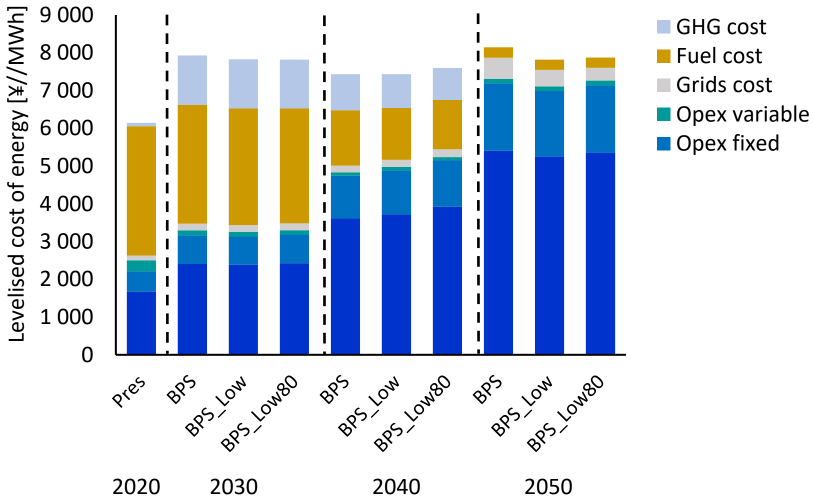


Figure 6.6: Levelized cost of energy for the BPS (left) variations.

Demand reduction does not lead to significantly lower cost of energy in 2050 across the scenarios, however, definitely should lead to lower cost in the longer term.

7. Conclusion

The fast defossilization and RE deployment as described in the Base Policy Scenario must be at the core of the energy policy of Japan in the years to come. Transition towards a 100% RE system and phasing out of GHG emissions by 2050 will not only ensure meeting the ambitious goal of the Paris Agreement, but also allow to build an energy system largely relying on domestic resources. A fast ramping of RE capacities and accelerated decarbonization from 2020s onwards is necessary to fulfill the ambitious 1.5°C target. Delayed decarbonization still allows to fulfill the modest NDC target and even converge to a 100% RE system, but at a cost of extremely high RE installation rates in the later years, in particular in the 2040s.

A quick defossilization can only be achieved through fast electrification of all the energy sectors. Direct electrification in heat and transport enables considerable efficiency improvements leading to an overall lower primary energy demand, and thus to lower cost. However, direct electrification is not possible all the time with the available technologies, e.g. in long distance aviation and maritime transport or specific high temperature industrial processes. In such cases, fossil fuels must be substituted with green synthetic fuels. The e-fuels synthesis process comes with significant conversion losses, requiring a lot more electricity than if the processes were directly electrified. It thus comes with a much lower efficiency and consequently higher cost of energy. Direct electrification therefore should be pursued wherever possible and only complemented with indirect electrification where necessary.

A delayed decarbonization scenario is worse or equal in all aspects but with higher emissions overall. A delayed defossilization would result in failing the ambitious 1.5°C climate target with significantly higher cumulative GHG emissions (27% higher than in the Base Policy Scenario), but also lead to a higher dependence on energy imports through the transition due to slower defossilization and lower electrification of road transport. It also leads to extremely high RE installation rates and subsequent investments in the later stages of the transition, with a cumulative cost of the system at the same level as for a faster decarbonization. However, in case of an accelerated decarbonization, much higher CO_2 price revenues are generated, included in the cumulative cost and that could return to the economy in the form of subsidies or support measures for climate investments or environment protection. Without taking into account those additional CO_2 costs, cumulative energy system cost in the Base Policy Scenario is about 2% lower. Showing several benefits, a fast decarbonization should be the central aim of the Japanese energy strategy.

The defossilization, electrification, and transition towards an energy supply based on variable RE sources results in a fast increase in electricity demand to satisfy the growing electricity demand for transport, space heating and industrial process heat. This in turn leads to a fast increase in generation capacity and demand for energy storage systems. Electricity generation grows from less than 1 000 TWh_{el} in 2020 to about 1 350 TWh_{el} by 2050 and the power generation capacity triples in case Japan imports about half of the synthetic fuels and part of the power it needs. In case it generates the synthetic fuels domestically, power generation grows to about 2 150 TWh_{el} and the power generation capacity quadruples by 2050, putting significantly more pressure on the energy system. Of all the technologies, solar PV becomes the least cost energy source in the system early in the transition and the technical potential of 524 GW set in this study is fully utilized in all the scenarios. More PV capacity could possibly be integrated into the system, which would allow to partially substitute higher cost onshore and offshore wind generation capacities, leading to a lower energy system cost.

To integrate those high levels of renewables and keep the balance of the system at all time, the electricity system will have to become significantly more flexible – through more battery storage, the deployment of heat pumps, electrolyzers and electric vehicles (notably with smart charging and vehicle-to-grid (V2G) technologies), and through more electricity trading between the regions. The spatial and temporal distribution of generation will balance variable generation and enable the efficient use of renewable electricity, the remaining conventional gas power plants also contributing importantly to this regard. The short-term balancing of electricity demand and supply will take place primarily through short-term storage (battery storage, smart charging and vehicle-to-grid technologies), load management and electricity trading. Balancing seasonal variations in electricity supply will be primarily achieved through the generation and reconversion of synthetic methane (power-to-gas and gas-to-power) with wind power from the northern regions, although this will not be required a lot thanks to the flexibility offered by the import of synthetic fuels.

By 2050 around 178 GWh of utility-scale and 275 GWh of prosumers battery storage capacity are required in the scenario where e-fuels are imported. Most of seasonal demand and supply fluctuations are balanced via sustainable energy imports and the seasonal synthetic gas storage utilization is limited to about 30 million cubic meters, much less than the present total underground gas storage capacity of about 2 140 million cubic meters. The capacity of the V2G storage can reach 427 GWh, and the throughput as much as 57 TWh_{el}, comparable to the throughput of utility-scale or prosumers battery storage. The impact of smart charging is harder to quantify, but the qualitative impact of the demand response from electric transportation will be higher than that of V2G services. Though smart charging and V2G services are currently not widely spread, its development and promotion must be considered in the energy strategy as a potential low-cost approach to ease variable RE phase-in.

The RE resources are distributed unevenly between the regions, i.e. the RE potential of the densely populated western and central regions of Japan is not sufficient to cover local energy demand, while the RE resources of Tohoku and Hokkaido far exceed local energy consumption. The transition to a 100% RE-based system significantly increases the role of power grids and energy exchange among regions. The role of grids especially increases in the 2040s, in the final phase of the transition, when additional electricity demand for e-fuels synthesis requires considerable amounts of electricity imports to western and central regions, mostly from wind farms in Hokkaido and Tohoku. The existing grids need to be reinforced while new grids are needed, which would be limited by relaxing the existing grid codes to allow higher utilization rates of the existing and expanded AC grids. In the import scenario, 17 GW of direct connection from Hokkaido to Tokyo would be needed in 2050 (much less than in the autarky scenario with 60 GW). The 50/60 Hz interconnection capacity also grows from 1.2 GW to 6 GW, indicating an increase in exchanges between the two grid areas (still much less than the 42 GW in the BPS autarky scenario). In 2050, more than 18% of electricity generated will be traded between the regions of Japan (33% in case of autarky), that will require considerable investments in the grid expansion, which should be started well in advance.

To integrate those high levels of renewables and keep the system balanced at all times, the electricity system will have to become significantly more flexible – through more battery storage, the deployment of heat pumps, electrolyzers and electric vehicles (notably with smart charging and vehicle-to-grid or V2G technologies), and through more electricity trading between regions. The spatial and temporal distribution of generation will balance variable generation and enable the efficient use of renewable electricity, while the remaining conventional gas power plants fill in gaps. The short-term balancing of electricity demand and supply will take place primarily through short-term storage (battery storage, smart charging and vehicle-to-grid technologies), load management and electricity trading. Seasonal variations in electricity supply will be primarily balanced through the generation and reconversion of synthetic methane (power-to-gas and gas-to-power) made with wind power from the northern regions, although this option will not be required much thanks to the flexibility offered by the import of synthetic fuels. Imported or domestically produced, the cost of synthetic fuels remains high. This results in overall higher cost of heat, especially for high temperature industrial heat, and direct electrification should be preferred where applicable. However, synthetic methane is an easily applicable solution as it can be based on an established gas infrastructure.

In any case, importing a large share of the e-fuels significantly reduces the pressure on the energy system with much less storage and grid capacity requirement, a lower power and primary energy demand, leading to lower capital investment needs and system costs. Even then, Japan would still rely on about 68% of local resources (against only 12% today), bringing much higher energy security. The dependence on specific countries for the import of synthetic energy carriers would be much lower, as imports could be distributed to several countries and regions in the world. The optimal balance of energy security and minimization of energy system costs requires a broad societal discourse.

Further efficiency improvements on the consumption side and further final energy consumption reduction would not lead to drastic changes in the transition pathway or the final energy system structure. The cumulative emissions would decrease proportionally to cumulative primary energy demand reduction through the transition. However, reduction in demand would decrease the dependence on the western and central regions for electricity supply from Hokkaido and Tohoku and overall decrease the grid utilization and expansion. In the tested cases of 10% and 20% lower energy consumption in 2050 the regional energy systems of most of the regions stay the same, showing that local electricity supply is cheaper than onshore wind energy imports from Hokkaido and Tohoku. In the long run, this leads to lower energy supply costs because the system avoids utilizing the costliest energy resources, and less investments are required for grid expansion, e-fuels synthesis and storage.

The results show that a fast defossilization of the energy system in Japan is possible and beneficial, leading to a more sustainable and self-sufficient energy system with affordable cost of energy supply. Further adapting the market design, re-evaluating land use requirements as well as removing cost barriers for the deployment and integration of renewables would lead to an even lower cost of energy supply. Such an energy transition will require an accurate planning of long-term investments but also a mix of instruments that combines market-based incentives, targeted support mechanisms and regulatory policies. Energy taxes, levies and duties will have to be reformed and carbon pricing increased, as existing price structures tend to promote fossil fuels. Import conditions for e-fuels will also need to be defined. Further analyses and discussions are now necessary to form the basis for a sustainable development of Japan beyond mid-century.

The scenarios at a glance

	2020	2030	2050	2030/2020 % change	2050/2020 % change
Energy-related GHG emissions (Mt CO_2eq)					
Total	**1 045**	**638**	**-**	**-39%**	**-100%**
Energy conversion	443	248	-	-44%	-100%
Industry	281	247	-	-1 206%	-100%
Buildings	119	38	-	-6 769%	-100%
Transport	203	105	-	-4 823%	-100%
Primary energy consumption (PJ) **Total**	**16 694**	**12 742**	**8 499**	**-24%**	**-49%**
Coal	4 843	1 073	-	-78%	-100%
Oil	3 001	1 604	-	-47%	-100%
Gas	7 406	8 320	-	+12%	-100%
Nuclear	611	-	-	-100%	-100%
Renewables	833	1 745	8 499	+109%	+920%
Electricity					
Gross electricity consumption (TWh_{el})	**962**	**1 009**	**2 074**	**+5%**	**+116%**
Gross electricity generation (TWh_{el})	970	1 021	2 165	+5%	+123%
Renewable share in generation (%)	18	39	100	+113%	+453%
Onshore wind capacity (GW)	4	18	144	+361%	+3 602%
Offshore wind capacity (GW)	0	7	199	+12 155%	+334 615%
Solar PV capacity (GW)	61	144	524	+134%	+752%
Number of electric vehicles (M)	1	12	44	+908%	+3 480%
Heat pumps (GW_{th})	46	89	140	+92%	+202%
Synthetic fuels demand (TWh_{th}) **Total**	**1**	**106**	**1 076**	**+7 507%**	**+77 220%**
Hydrogen (TWh_{th})	1	76	834	+5 360%	+59 794%
Share of import	-	-	*0%*		
SNG (TWh_{th})	-	12	154		
Share of import	-	-	*0%*		
FT (TWh_{th})	-	18	89		
Share of import	-	-	*78%*		
Domestic electrolyzer capacity (GW_{el})	-	1	197		
Power input for green H2 production (share of power generation) (%)	-	*0.3%*	*47%*		
-	-				
Population in Japan (M)	125	117	100		
CO_2 price (JPY/t_{CO2})	289	5 496	18 000		

Figure A: Base Policy Scenario - Autarky at a glance

	2020	2030	2050	2030/2020 % change	2050/2020 % change
Energy-related GHG emissions (Mt CO_2eq)					
Total	**1 045**	**638**	**-**	**-39%**	**-100%**
Energy conversion	443	248	-	-44%	-100%
Industry	281	247	-	-12%	-100%
Buildings	119	38	-	-68%	-100%
Transport	203	105	-	-48%	-100%
Primary energy consumption (PJ) Total	**16 694**	**12 742**	**7 698**	**-24%**	**-54%**
Coal	4 843	1 073	-	-78%	-100%
Oil	3 001	1 604	-	-47%	-100%
Gas	7 406	8 320	-	12%	-100%
Nuclear	611	-	-	-100%	-100%
Renewables	833	1 745	7 698	+109%	+824%
Electricity					
Gross electricity consumption (TWh_{el})	**962**	**1 009**	**1 430**	**+5%**	**+49%**
Gross electricity generation (TWh_{el})	970	1 021	1 351	+5%	+39%
Renewable share in generation (%)	18	39	100	+113%	+453%
Onshore wind capacity (GW)	4	18	88	+361%	+2 168%
Offshore wind capacity (GW)	0	7	63	+12 155%	+105 048%
Solar PV capacity (GW)	61	144	524	+134%	+752%
Number of electric vehicles (M)	1	12	44	+908%	+3 480%
Heat pumps (GW_{th})	46	89	142	+92%	+207%
Synthetic fuels demand (TWh_{th}) Total	**1**	**106**	**947**	**+7 507%**	**+67 906%**
Hydrogen (TWh_{th})	1	76	670	+5 360%	+48 034%
Share of import	-	-	*47%*		
SNG (TWh_{th})	-	12	188		
Share of import	-	-	*94%*		
FT (TWh_{th})	-	18	89		
Share of import	-	-	*78%*		
Domestic electrolyzer capacity (GW_{el})	-	1	73		
Power input for green H2 production (share of power generation) (%)	-	*0.3%*	*32%*		
-	-				
Population in Japan (M)	125	117	100		
CO_2 price (JPY/t_{CO2})	289	5 496	18 000		

Figure B: Base Policy Scenario - all import at a glance

		2020	2030	2050	2030/2020 % change	2050/2020 % change
Energy-related GHG emissions (Mt CO_2eq)						
	Total	**1 045**	**638**	**-**	**-18%**	**-100%**
	Energy conversion	443	248	-	-13%	-100%
	Industry	281	247	-	-9%	-100%
	Buildings	119	38	-	-46%	-100%
	Transport	203	105	-	-23%	-100%
Primary energy consumption (PJ)	**Total**	**16 694**	**14 693**	**8 689**	**-12%**	**-48%**
	Coal	4 843	3 708	-	-23%	-100%
	Oil	3 001	2 317	-	-23%	-100%
	Gas	7 406	6 707	-	-9%	-100%
	Nuclear	611	650	160	+6%	-100%
	Rrenewables	833	1 311	8 529	+57%	+923%
Electricity						
	Gross electricity consumption (TWh_{el})	**962**	**954**	**2 064**	**-1%**	**+115%**
	Gross electricity generation (TWh_{el})	970	972	2 133	0%	+120%
	Renewable share in generation (%)	18	29	99	+60%	+449%
	Onshore wind capacity (GW)	4	10	144	+361%	+3 600%
	Offshore wind capacity (GW)	0	1	188	+12 155%	+315 095%
	Solar PV capacity (GW)	61	107	524	+74%	+752%
	Number of electric vehicles (M)	1	5	31	+298%	+2 414%
	Heat pumps (GW_{th})	46	69	139	+48%	+199%
Synthetic fuels demand (TWh_{th})	**Total**	**1**	**99**	**1 140**	**+7 022%**	**+81 779%**
	Hydrogen (TWh_{th})	1	69	834	+4 857%	+59 794%
	Share of import	-	-	*0%*		
	SNG (TWh_{th})	-	6	147		
	Share of import	-	-	*0%*		
	FT (TWh_{th})	-	24	159		
	Share of import	-	-	*84%*		
	Domestic electrolyzer capacity (GW_{el})	-	6	199		
	Power input for green H2 production (share of power generation) (%)	-	*5%*	*48%*		
	-	-				
	Population in Japan (M)	125	117	100		
	CO_2 price (JPY/t_{CO2})	289	2 748	9 000		

Figure C: Delayed Policy Scenario at a glance

Nomenclature

A-CAES	adiabatic compressed air energy storage
BAU	business as usual
BEV	battery-electric vehicle
BF-BOF	blast furnace-basic oxygen furnace
BPS	Base Policy Scenario
CAGR	compound annual growth rate
Capex	capital expenditures
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CF	capacity factor
CHP	combined heat and power
CSP	concentrating solar power
C&I	Commercial & industry
DAC	CO_2 direct air capture
EAF	electric arc furnace
EV	electric vehicle
EWIN	electrowinning of iron
FCEV	fuel cell electric vehicle
FED	Final energy demand
FLh	full load hours
GDP	gross domestic product
GHG	greenhouse gases
H-DRI	hydrogen-based direct reduced iron
HDV	heavy duty transport
HtP	heat-to-power
HVAC	high voltage alternating current
HVDC	high voltage direct current
ICE	internal combustion engine
LCOC	levelized cost of curtailment
LCOE	levelized cost of electricity
LCOH	levelized cost of heat
LCOS	levelized cost of storage
LCOT	levelized cost of transmission

LDV	light duty vehicle
LNG	liquefied methane
MDV	medium duty vehicle
NTC	net transfer capacity
OCGT	open cycle gas turbine
OECD	Organisation for Economic Co-operation and Development
Opex	operational expenditures
PED	Primary energy demand
PHES	pumped hydro energy storage
PHEV	plug-in electric vehicle
PtG	power-to-gas
PtH	power-to-heat
PP	power plant
PV	photovoltaic
RE	renewable energy
SNG	synthetic natural gas
ST	steam turbine
SWRO	seawater reverse osmosis
TES	thermal energy storage
V2G	vehicle-to-grid
WACC	weighted average cost of capital
2/3W	2-3 wheeled transport

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Appendix

Methodology

The LUT Energy System Transition model has integrated all crucial aspects of the power, heat and transport sectors into an integrated energy system. Moreover, the model includes prosumers, both power and heat, as part of the energy system. The industrial energy demand is considered in power and heat sectors. The fundamental approach is shown in Figure A1.

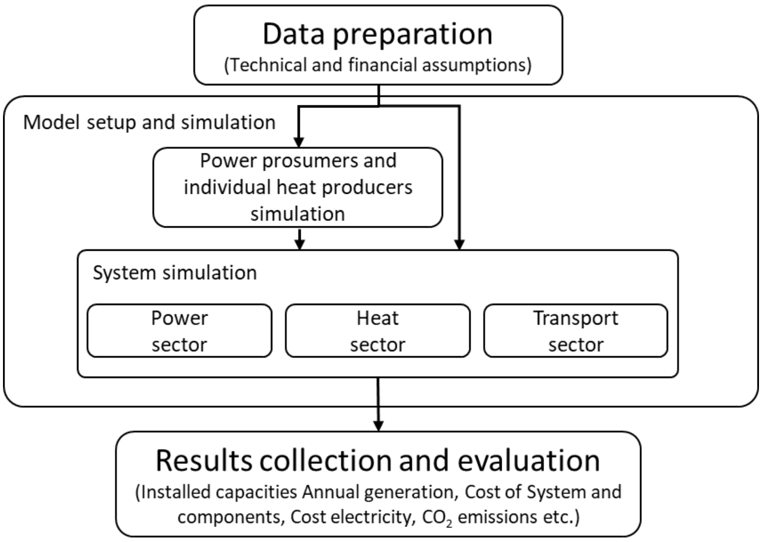

Figure A1: Fundamental structure of the LUT Energy System Transition model.

The optimization model of the energy system is based on a linear optimization of the system parameters under a set of applied constraints with the assumption of a perfect foresight of renewable energy generation and energy demand. A multi-node approach enables the description of any desired configuration of the sub-regions and power transmission interconnections. The main constraint of the optimization is matching of the total energy generation and the total energy demand values for every hour of the applied year. The optimization criterion is to minimize the total annual cost of the system. The hourly resolution of the model significantly increases the computation time. However, it guarantees that for every hour of the year the total supply within a sub-region covers the local demand and enables a more precise system description including synergy effects of different system components.

The optimization is performed using a third-party solver. Currently, the main option is MOSEK ver. 7, but other solvers (Gurobi, CPLEX, etc.) can also be used. The model is compiled in a Matlab environment in the LP file format, so that the model can be read by most of the available solvers. After the simulation, results are parsed back to the Matlab data structure and post-processed. A detailed description is provided in Bogdanov et al. [5].

Power, heat and transport sectors

The model simulates an integrated energy system development under specific given conditions as shown in Figure A2. For every time step the model defines a cost optimal energy system structure and operation mode for the given set of constraints: power demand, heat demand for industry, space and domestic water heating, energy demand for transport, available generation and storage technologies, financial and technical parameters, and limits on installed capacity for all available technologies. The target of the optimization is the minimization of the total system cost. The cost of the entire energy system is calculated as a sum of the annualized capital, operational expenditures (including ramping costs), fuel costs and GHG emission costs for all available technologies. The transition simulation is performed for the period from 2020 to 2050 in five-year time intervals.

The distributed generation and self-consumption of the residential, commercial, and industrial prosumers are included in the energy system analysis and defined with a special model describing the development of the individual power and heat generation capacities. The prosumers can install their own rooftop PV systems, lithium-ion batteries, buy power from the grid, or sell surplus electricity in order to fulfil their demand. At the same time prosumers can install individual heaters for space and water heating. The target function for prosumers is minimization of the cost of consumed electricity and heat, calculated as a sum of equipment annual costs for self-generation, costs of fuels, and costs of electricity consumed from the grid. The share of consumers that is expected to be interested in self-generation gradually increases from 9% in 2020 to an in-built limit of 15% by 2050.

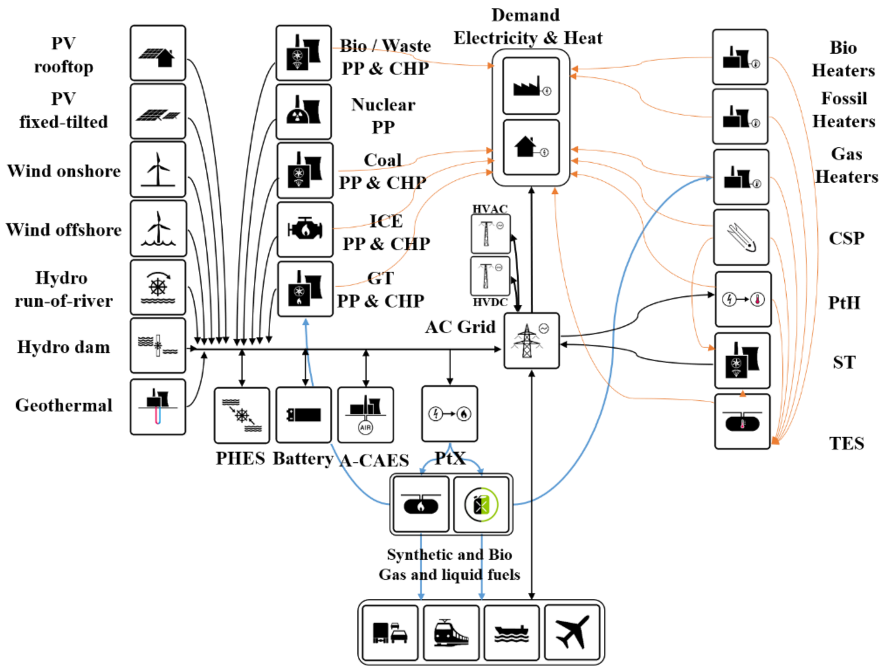

Figure A2: Schematic of the LUT Energy System Transition model comprised of energy converters for power and heat, storage technologies, transmission options, and demand sectors. Adapted from Bogdanov et al. [21].

The model has integrated all crucial aspects of an energy system. The fossil electricity generation technologies are coal power plants, combined heat and power (CHP), oil-based internal combustion engine (ICE) and CHP, open cycle (OCGT) and combined cycle gas turbines (CCGT), and gas-based CHP.

The RE electricity generation technologies are solar PV (optimally fixed-tilted, single-axis north-south tracking, and rooftop), wind turbines (onshore and offshore), hydropower (run-of-river and reservoir), geothermal, and bioenergy (solid biomass, biogas, waste-to-energy power plants, and CHP). The fossil heat generation technologies are coal-based district heating, oil-based district and individual scale boilers, and gas-based district and individual scale boilers. The RE-based heat generation technologies are concentrated solar thermal power (CSP) parabolic fields, individual solar thermal water heaters, geothermal district heaters, and bioenergy (solid biomass, biogas district heat, and individual boilers).

The storage technologies can be divided into three main categories: short-term storage with lithium-ion batteries and pumped hydro energy storage (PHES); medium-term storage with adiabatic compressed air energy storage (A-CAES), and high and medium temperature thermal energy storage (TES) technologies; and long-term gas storage including power-to-gas (PtG) technology, which allows the production of synthetic methane to be utilized in the system.

The bridging technologies are power-to-gas, steam turbines, electrical heaters, district and individual scale heat pumps, and direct electrical heaters. These technologies convert energy from one sector into valuable products for another sector in order to increase the total system flexibility, efficiency, and decrease overall costs. A detailed overview can be found in Bogdanov et al. [5].

The transportation demand is derived for the modes: road, rail, maritime transport, and aviation for passenger and freight transport. The road segment is subdivided into passenger LDV, passenger 2W/3W, passenger bus, freight MDV, and freight HDV. The other transportation modes are comprised of demand for freight and passengers. The demand is estimated in passenger kilometers (p-km) for passenger transport and in tonne kilometers (t-km) for freight transport.

The transportation demand is converted into energy demand by assuming an energy transition from current fuels to fully sustainable fuels by 2050, whereas the following principal fuel types are taken into account and visualized in Figure A3:

- Road: electricity, hydrogen, liquid fuels;
- Rail: electricity, liquid fuels (in case of Japan fully electrified);
- Maritime: electricity, hydrogen, methane, liquid fuels (in case of Japan only liquid fuels);
- Aviation: electricity, hydrogen, liquid fuels (in case of Japan only liquid fuels).

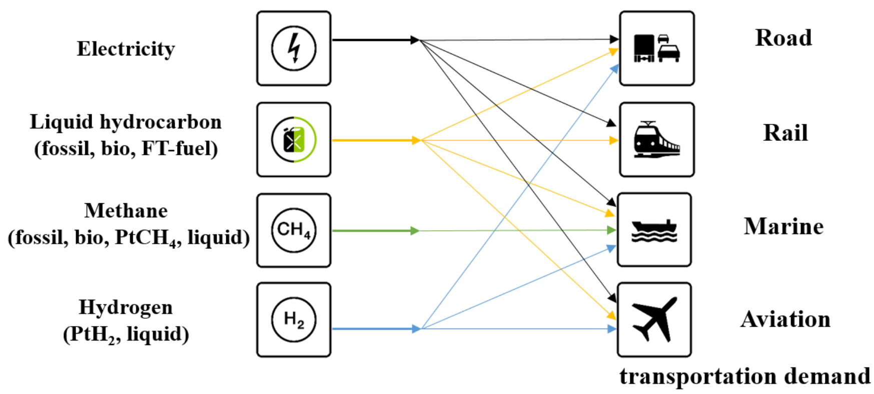

Figure A3: Schematic of the transport modes and corresponding fuels utilized during the energy transition period.

The fuel conversion process adopted to produce sustainable fuels is shown in Figure A4.

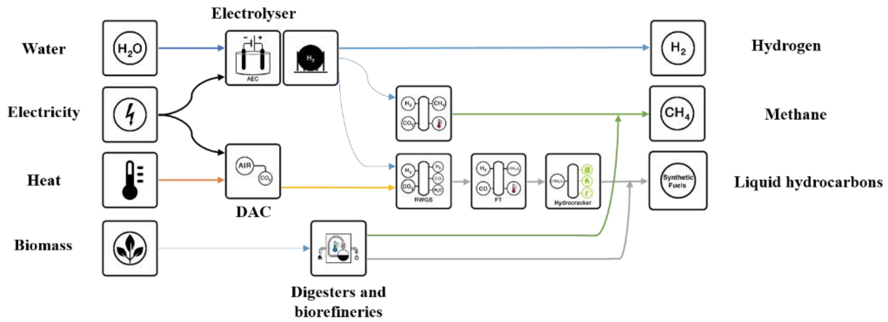

Figure A4: Schematic of the value chain elements in the production of sustainable fuels.

The battery-electric vehicles (BEV) and plug-in hybrid electric vehicles (PHEV) can provide additional flexibility to the system with smart charging and vehicle-to-grid (V2G) services. In case of smart charging the vehicles are charged more during electricity surplus periods and less during electricity production deficit, eventually allowing to decrease storage utilization in the RE-based energy system. The vehicles enabled with V2G operate as a virtual storage, providing part of the battery capacity to the system to be charged and discharged accordingly to the system balancing requirements. The availability of the V2G capacity is limited by the vehicles utilization profile, so that the power system can only access the battery capacity of the stationary vehicles which are grid connected at the given hour.

Data preparation

This includes determining long-term energy demand across the different sectors of power, heat and transport. In addition, it involves generating hourly demand profiles across all energy sectors, but also creating a database of power plants across Japan. Additionally, assessing the resource potentials of various renewable energy technologies across the different regions of Japan is a vital input. Furthermore, technical and financial details including assumptions for all technologies are collated. All relevant data are organized across the nine regions through the transition period from 2020 to 2050, in five-year intervals.

- **Financial and technical assumptions**

The financial and technical assumptions are based on a wide list of sources, which are Japan specific and global market data. For most of the technologies Japan specific financial assumptions are used, for new technologies, currently not represented on the Japanese market, the global market assumptions are used with an additional market premium for the higher cost level in Japan within the range of 20-100% in 2020 (based on the observed cost difference for most of technologies such as PV, wind turbines and gas turbines), decreasing to a market premium in the range of 0-20% in 2050 to reflect the impact of the higher labor cost and area limitation. The financial and technical assumptions for power and heat generation, energy storage, power transmission, e-fuels production technologies and references to the sources are summarized in the Table A1.

The fossil fuels costs assumptions are based on BNEF and summarized in the Table A2. The carbon pricing assumptions are summarized in the Table A3.

The cost assumptions related to the sustainable electricity imports are based on simulations for Northeast China and Russia Far East regions (for electricity production cost estimations) and the transmission grid connection costs. The e-fuels imports costs are based on the simulation for the West Australia region (for e-fuels production cost estimations) and the e-fuels transport costs. The cost assumptions for electricity and e-fuels imports are summarized in the Table A4.

- **Development of energy demand**

The power, heat and cooling demand assumptions for residential, commercial and industrial sectors is based on the METI's statistics [8], currently available till FY2017. The available statistics numbers were extrapolated to estimate 2020 demand levels. The data on prefectures level was summed up accordingly to EPCO areas borders, in case of Shizuoka the demand was divided between Tokyo and Chubu EPCO's area. The numbers were reprocessed to estimate the final energy consumption for power and heat: final electricity consumption of residential, commercial and industrial sectors excluding electricity for heat and transport applications (Table A5), final electricity consumption for cooling in residential, commercial sectors applications (Table A6), final heat consumption of residential, commercial and industrial sectors, divided in space heating demand (Table A7), water heating demand (Table A8) and industrial heat demand (Table A9). In the transition period 2020-2050, final electricity and heat demand is assumed to continuously decrease due to population decrease and efficiency improvements on consumption side. In 2050, final electricity consumption for general electric appliances and lighting is assumed to be 20% lower than in 2020. The residential and commercial demand is assumed to be 20% lower, while industrial demand is assumed to drop by 30%, while electricity for cooling is assumed to decrease less, only by 6%, due to rebound effects.

The demand profiles on an hourly basis for the integrated energy sector based on regional variation were computed through the transition from 2020 to 2050, in five-year intervals. The synthetic electricity demand profiles from 2020 until 2050 are generated based on the methods from Toktarova et al. [22]. The space heating demand profiles are estimated based on the degree-hours approach.

The transmission and distribution losses in the regional power systems are based on the World Bank [23] statistics and extrapolated for 2020-2050 based on Sadovskaia et al. [24], the T&D losses assumptions are provided in the Table A10. For heat, the losses in the district heating distribution system are assumed to linearly decrease from 12% in 2020 to 6% in 2050, while the share of district heating linearly increases from nearly 0 in 2020 to 5% in 2050. The industrial heat is categorized into three categories: low temperature, medium temperature (MT) and high temperature (HT) heat demand. The share of low temperature demand is assumed to be 25%, medium heat share is 11% and high temperature heat demand (fuel-based industrial processes demand for iron reduction, etc.) is set to 64% constant through the transition. The structure of the heat demand through the transition is presented in Figure A5.

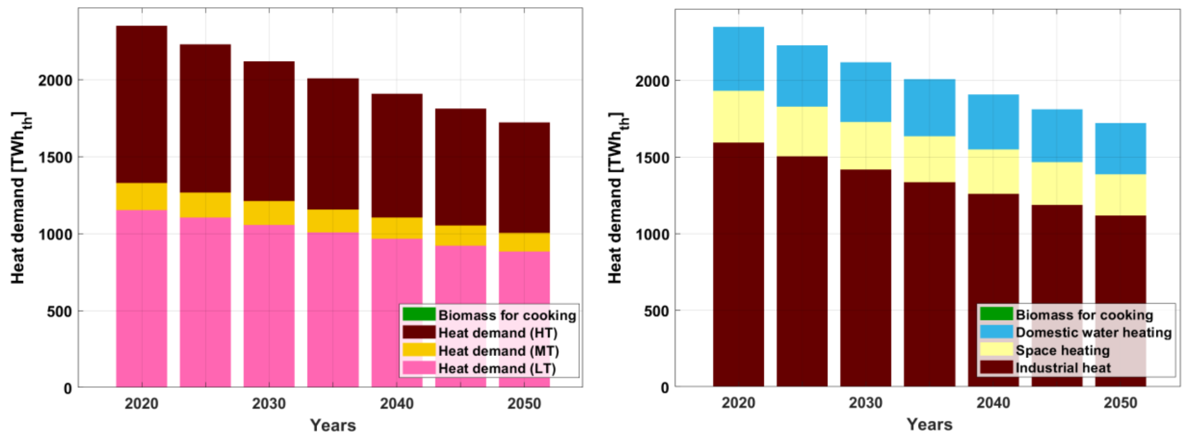

Figure A5: Evolution of heat demand per type (left) and per application (right) from 2020 to 2050.

The transportation services demand is assumed based on the expected population decline [9] and the METI projection of transportation volumes for 2030 [10] and an extrapolation till 2050. The demand is derived for the modes: road, rail, maritime transport, and aviation for passenger and freight transport. The road segment is subdivided into passenger light duty vehicles (LDV), passenger bus (BUS), freight medium duty vehicles (MDV), and freight heavy duty vehicles (HDV). The other transport segments are comprised of demand for freight and passengers. The demand is estimated in passenger kilometers (p-km) for passenger transport and in tonne kilometers (t-km) for freight transport. The data have been available on country level, and regional values for road and rail transport were estimated based on regions' shares of the country totals, mainly in population [25], and for aviation and maritime transport based on regional airports and seaports passengers and freight throughput. The freight and passenger transport demand are summarized in the Tables A11-A17 for LDV (Table A11), BUS (Table A12), MDV (Table A13), HDV (Table A14), rail (Table A15), maritime transport (Table A16) and aviation (Table A17) transport. The final passenger demand and freight demand are shown in Figure A6.

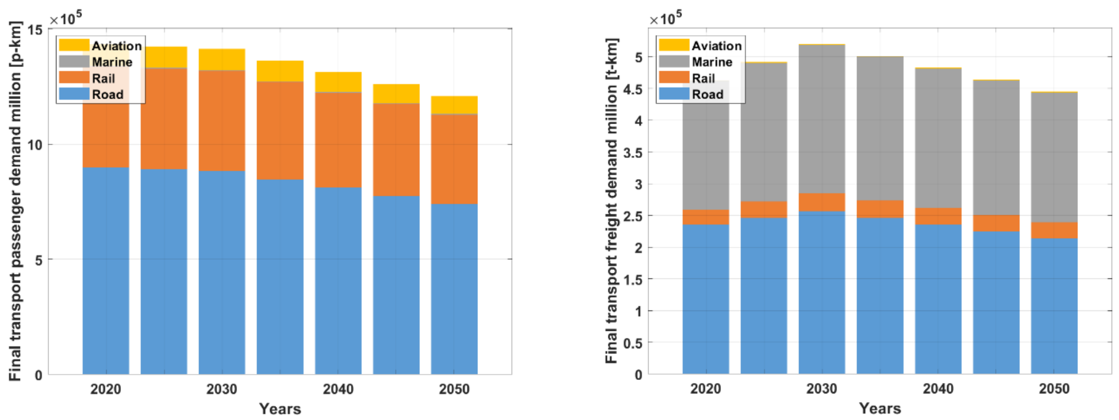

Figure A6: Development of final transport passenger demand (left) and freight demand (right) from 2015 to 2050 for Japan.

All rail transport is assumed to be electrified, while maritime transport and aviation is assumed to rely on liquid fuels use throughout the transition, however fossil fuels can be substituted by bio- and e-fuels at later steps of the transition. For the road transport gradual transition towards lower shares of conventional internal combustion engine (ICE) vehicles was assumed. For the BPS the fuel shares of the transport modes in the road segment are based directly or indirectly on levelized cost of mobility (LCOM) considerations for newly sold vehicles, which change the stock of vehicles according to the lifetime composition of the existing stock, based on Breyer et al. [26]. For the DPS a slower introduction of BEV was assumed. The fuels shares for road transport types for the BPS and DPS are presented in the Tables A18-21: LDV (Table A18), BUS (Table A19), MDV (Table A20), and HDV (Table A21).

The specific energy consumption by transport means are based on METI statistics [4] and future estimation of efficiency improvements are based on Khalili et al. [11]. The specific fuel consumption values for all transport modes and all fuel types throughout the transition are presented in Table A22.

The share of BEV and PHEV with enabled smart charging is set at 80% for all the years. The share of PHEV in LDV and MDV with enabled V2G increases from zero in 2020 to 16% in 2050, while for BUS and HDV V2G is assumed to be not possible. The shares of vehicles with V2G services enabled are summarized in Table A23.

- **Resource potential for renewable energy technologies**

The generation profiles for optimally fixed-tilted PV and wind energy are calculated according to Bogdanov and Breyer [12] using global weather data for the year 2005 from NASA [13,14] and reprocessed by the German Aerospace Centre [15]. The profiles for onshore wind turbines are calculated for a 4 MW turbine at 120 m hub height, while the offshore wind profiles are calculated for a 10 MW turbine at 140 m hub height. The hydropower feed-in profiles are computed based on daily resolved water flow data for the year 2005 [16]. The potentials for biomass and waste resources are classified into four main categories: forest industry wastes, solid wastes, solid residues and biogas. Resources potential assumptions are based on data from the Food and Agriculture Organization of the United Nations [17] for agriculture and forestry residues and from the World Bank [18] for wastes potential. The cost assumptions are based on METI data [19]~~.~~ The geothermal energy potential is estimated according to projections of the Ministry of Environment [27].

The full load hours (FLH) for PV, wind and hydropower generation technologies and biomass potential by category is summarized in Table A24.

Lists of tables

Financial and technical assumptions

The following tables show the various financial and technical assumptions that were factored into the modelling of the energy transition scenarios.

***Table A 1**: Technical and financial assumptions of energy system technologies used in the energy transition from 2020 to 2050.*

Technologies		Unit	2020	2025	2030	2035	2040	2045	2050	Source
PV fixed tilted PP	Capex	¥/kW_{el}	145 500	104 950	64 400	57 700	51 000	47 500	44 000	[28] [29] [30]
	Opex fix	¥/(kW_{el} a)	3 157	2 414	1 843	1 777	1 711	1 652	1 592	
	Opex var	¥/kWel	0	0	0	0	0	0	0	
	Lifetime	years	30	30	30	35	35	40	40	
PV rooftop – residential	Capex	¥/kW_{el}	226 000	150 000	108 000	74 640	66 120	59 520	54 360	[28] [30] [31]
	Opex fix	¥/(kW_{el} a)	2 354	1 250	650	470	430	380	332	
	Opex var	¥/kWh_{el}	0	0	0	0	0	0	0	
	Lifetime	years	30	35	35	35	40	40	40	
PV rooftop – commercial	Capex	¥/kW_{el}	187 000	133 500	80 000	77 500	75 000	63 000	56 000	[28] [30] [31]
	Opex fix	¥/(kW_{el} a)	2 200	1 548	951	958	918	800	744	
	Opex var	¥/kWh_{el}	0	0	0	0	0	0	0	
	Lifetime	years	30	35	35	35	40	40	40	
PV rooftop – industrial	Capex	¥/kW_{el}	165 000	117 794	70 588	69 794	69 000	59 000	52 000	[28] [30] [31]
	Opex fix	¥/(kW_{el} a)	1 407	945	621	784	817	749	672	
	Opex var	¥/kWh_{el}	0	0	0	0	0	0	0	
	Lifetime	years	30	35	35	35	40	40	40	
Wind onshore PP	Capex	¥/kW_{el}	272 000	210 250	148 500	120 000	116 667	113 333	110 000	[30] [32]
	Opex fix	¥/(kW_{el} a)	9 300	7 189	5 077	4 103	3 989	3 875	3 761	
	Opex var	¥/kWh_{el}	0	0	0	0	0	0	0	
	Lifetime	years	25	25	25	25	25	25	25	
Wind offshore PP	Capex	¥/kW_{el}	600 000	430 000	329 000	266 000	260 000	257 000	256 000	[30]
	Opex fix	¥/(kW_{el} a)	17 145	12 257	9 475	7 682	7 441	7 309	7 296	
	Opex var	¥/kWh_{el}	0	0	0	0	0	0	0	
	Lifetime	years	25	25	25	25	25	25	25	
Hydro Run-of-River PP	Capex	¥/kW_{el}	640 000	640 000	640 000	640 000	640 000	640 000	640 000	[33]
	Opex fix	¥/(kW_{el} a)	9 140	9 140	9 140	9 140	9 140	9 140	9 140	
	Opex var	¥/kWh_{el}	1.25	1.25	1.25	1.25	1.25	1.25	1.25	
	Lifetime	years	60	60	60	60	60	60	60	
Hydro Reservoir/ Dam	Capex	¥/kW_{el}	640 000	640 000	640 000	640 000	640 000	640 000	640 000	[33]
	Opex fix	¥/(kW_{el} a)	9 140	9 140	9 140	9 140	9 140	9 140	9 140	
	Opex var	¥/kWh_{el}	1.16	1.16	1.16	1.16	1.16	1.16	1.16	
	Lifetime	years	60	60	60	60	60	60	60	
Geothermal PP	Capex	¥/kW_{el}	1 143 000	1 143 000	1 143 000	976 265	924 519	877 373	830 227	[30]
	Opex fix	¥/(kW_{el} a)	24 200	24 200	24 200	20 670	19 574	18 576	17 578	
	Opex var	¥/kWh_{el}	0	0	0	0	0	0	0	
	Efficiency	%	23.9	23.9	23.9	23.9	23.9	23.9	23.9	
	Lifetime	years	40	40	40	40	40	40	40	

CCGT PP	Capex	¥/kW$_{el}$	126 000	126 000	126 000	126 000	126 000	126 000	126 000	[33] [34]
	Opex fix	¥/(kW$_{el}$ a)	3 651	3 651	3 651	3 651	3 651	3 651	3 651	
	Opex var	¥/kWh$_{el}$	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
	Efficiency	%	58.0	58.0	58.0	59.0	60.0	60.0	60.0	
	Lifetime	years	35	35	35	35	35	35	35	
OCGT PP	Capex	¥/kW$_{el}$	113 400	113 400	113 400	113 400	113 400	113 400	113 400	[33] [34]
	Opex fix	¥/(kW$_{el}$ a)	3 402	3 402	3 402	3 402	3 402	3 402	3 402	
	Opex var	¥/kWh$_{el}$	3	3	3	3	3	3	3	
	Efficiency	%	40.0	41.5	43.0	43.5	44.0	44.5	45.0	
	Lifetime	years	35	35	35	35	35	35	35	
CCGT PP + CCS	Capex	¥/kW$_{el}$	555 600	485 400	415 200	382 000	350 400	333 600	316 800	[34]
	Opex fix	¥/(kW$_{el}$ a)	18 441	16 111	13 781	12 706	11 630	11 073	10 515	
	Opex var	¥/kWh$_{el}$	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
	Efficiency	%	52.0	52.5	53.0	53.5	54.0	54.5	55.0	
	Lifetime	years	35	35	35	35	35	35	35	
Int Combust Generator	Capex	¥/kW$_{el}$	91 914	91 914	91 914	91 914	91 914	91 914	91 914	[35]
	Opex fix	¥/(kW$_{el}$ a)	2 745	2 745	2 745	2 745	2 745	2 745	2 745	
	Opex var	¥/kWh$_{el}$	1.1	1.1	1.1	1.1	1.1	1.1	1.1	
	Efficiency	%	40.0	40.0	40.0	40.0	40.0	40.0	40.0	
	Lifetime	years	30	30	30	30	30	30	30	
Multifuel Int Combust Generator	Capex	¥/kW$_{el}$	135 841	132 021	128 202	124 621	120 801	117 220	113 400	[35]
	Opex fix	¥/(kW$_{el}$ a)	1 480	1 439	1 397	1 358	1 316	1 277	1 236	
	Opex var	¥/kWh$_{el}$	2.6	2.6	2.5	2.4	2.3	2.3	2.2	
	Efficiency	%	47.0	47.0	47.0	47.0	47.0	47.0	47.0	
	Lifetime	years	30	30	30	30	30	30	30	
Coal PP	Capex	¥/kW$_{el}$	262 500	262 500	262 500	262 500	262 500	262 500	262 500	[33] [36]
	Opex fix	¥/(kW$_{el}$ a)	9 944	9 944	9 944	9 944	9 944	9 944	9 944	
	Opex var	¥/kWh$_{el}$	2.6	2.6	2.6	2.6	2.6	2.6	2.6	
	Efficiency	%	43.0	43.0	43.0	43.0	43.0	43.0	43.0	
	Lifetime	years	45	45	45	45	45	45	45	
Coal PP + CSS	Capex	¥/kW$_{el}$	980 100	874 403	768 706	720 662	672 618	648 062	623 506	[35]
	Opex fix	¥/(kW$_{el}$ a)	44 024	39 276	34 529	32 371	30 213	29 110	28 007	
	Opex var	¥/kWh$_{el}$	9.8	8.7	7.7	7.2	6.7	6.5	6.2	
	Efficiency	%	37	38	39	40	40	41	41	
	Lifetime	years	45	45	45	45	45	45	45	
Biomass PP	Capex	¥/kW$_{el}$	417 900	394 772	371 644	350 111	328 578	310 235	291 892	[30]
	Opex fix	¥/(kW$_{el}$ a)	27 000	25 506	24 011	22 620	21 229	20 044	18 859	
	Opex var	¥/kWh$_{el}$	21	20	19	18	16	16	15	
	Efficiency	%	36.0	36.5	37.0	37.5	38.0	38.5	39.0	
	Lifetime	years	25	25	25	25	25	25	25	
Nuclear PP	Capex	¥/kW$_{el}$	1 342 000	1 342 000	1 342 000	1 342 000	1 342 000	1 342 000	1 342 000	[35] [37] [38] [39]
	Opex fix	¥/(kW$_{el}$ a)	14 630	14 630	14 630	14 630	14 630	14 630	14 630	
	Opex var	¥/kWh$_{el}$	0.56	0.56	0.56	0.56	0.56	0.56	0.56	
	Efficiency	%	37.0	37.0	38.0	38.0	38.0	38.0	38.0	
	Lifetime	years	40	40	40	40	40	40	40	

CHP NG Heating	Capex	¥/kW_{el}	127 050	127 050	127 050	127 050	127 050	127 050	127 050	[33]
	Opex fix	¥/(kW_{el} a)	10 000	10 000	10 000	10 000	10 000	10 000	10 000	
	Opex var	¥/kWh_{el}	0.35	v	0.3	0.3	0.3	0.3	0.3	
	Efficiency Heating	%	36.6	37.3	38.0	38.3	38.7	39.1	39.4	
	Efficiency Electricity	%	51.0	52.0	53.0	53.5	54.0	54.5	55.0	
	Lifetime	years	30	30	30	30	30	30	30	
CHP Oil Heating	Capex	¥/kW_{el}	136 500	136 500	136 500	136 500	136 500	136 500	136 500	[33]
	Opex fix	¥/(kW_{el} a)	7 900	7 900	7 900	7 900	7 900	7 900	7 900	
	Opex var	¥/kWh_{el}	0.4	0.4	0.4	0.4	0.4	0.4	0.4	
	Efficiency Heating	%	50.0	50.0	50.0	50.0	50.0	50.0	50.0	
	Efficiency Electricity	%	30.0	30.0	30.0	30.0	30.0	30.0	30.0	
	Lifetime	years	30	30	30	30	30	30	30	
CHP Biomass Heating	Capex	¥/kW_{el}	542 313	526 363	510 412	498 449	486 487	474 524	462 561	[40]
	Opex fix	¥/(kW_{el} a)	15 568	15 110	14 652	14 308	13 965	13 622	13 278	
	Opex var	¥/kWh_{el}	0.6	0.6	0.6	0.6	0.5	0.5	0.5	
	Efficiency Heating	%	65.1	65.2	65.3	65.0	64.8	64.5	64.2	
	Efficiency Electricity	%	29.5	29.6	29.6	29.5	29.4	29.2	29.1	
	Lifetime	years	25	25	25	25	25	25	25	
CHP Biogas	Capex	¥/kW_{el}	191 600	178 386	165 172	124 181	92 212	62 658	35 520	[40] [38]
	Opex fix	¥/(kW_{el} a)	10 700	9 962	9 224	6 935	5 150	3 499	1 984	
	Opex var	¥/kWh_{el}	0.4	0.4	0.4	0.3	0.2	0.1	0.1	
	Efficiency Heating	%	43.0	46.5	50.0	52.3	54.7	54.7	54.7	
	Efficiency Electricity	%	34.4	37.2	40.0	41.9	43.7	43.7	43.7	
	Lifetime	years	30	30	30	30	30	30	30	
MSW incinerator	Capex	¥/kW_{el}	965 000	932 433	898 153	797 519	709 567	623 070	544 800	[38]
	Opex fix	¥/(kW_{el} a)	39 000	37 684	36 298	32 231	28 677	25 181	22 018	
	Opex var	¥/kWh_{el}	1.2	1.1	1.1	1.0	0.9	0.8	0.7	
	Efficiency Heating	%	71.0	71.0	71.0	71.0	71.0	71.0	71.0	
	Efficiency Electricity	%	26.0	26.0	26.0	26.0	26.0	26.0	26.0	
	Lifetime	years	30	30	30	30	30	30	30	
Utility-scale Electric Heating	Capex	¥/kW_{th}	24 000	24 000	18 000	15 750	13 500	11 250	9 000	[40]
	Opex fix	¥/(kW_{th} a)	353	353	265	232	198	165	132	
	Opex var	¥/kWh_{th}	0.1	0.1	0.1	0.1	0.1	0.1	0.05	
	Efficiency	%	100	100	100	100	100	100	100	
	Lifetime	years	35	35	35	35	35	35	35	
Utility-scale Heat Pump	Capex	¥/kW_{th}	79 200	74 160	70 800	68 160	66 480	64 800	63 600	[41]
	Opex fix	¥/(kW_{th} a)	240	225	215	207	201	196	193	
	Opex var	¥/kWh_{th}	0.2	0.2	0.2	0.2	0.2	0.2	0.2	
	CoP		3.3	3.4	3.5	3.6	3.6	3.7	3.8	
	Lifetime	years	25	25	25	25	25	25	25	

Utility-scale NG Heating	Capex	¥/kW$_{th}$	18 000	18 000	24 000	21 300	18 600	15 900	13 200	[40]
	Opex fix	¥/(kW$_{th}$ a)	666	666	888	788	688	588	488	
	Opex var	¥/kWh$_{th}$	0.04	0.04	0.05	0.04	0.04	0.03	0.03	
	Efficiency	%	97.0	97.0	97.0	97.0	97.0	97.0	97.0	
	Lifetime	years	35	35	35	35	35	35	35	
Utility-scale Biomass Heating	Capex	¥/kW$_{th}$	18 000	18 000	24 000	21 300	18 600	15 900	13 200	[40]
	Opex fix	¥/(kW$_{th}$ a)	672	672	896	795	694	594	493	
	Opex var	¥/kWh$_{th}$	0.04	0.04	0.05	0.04	0.04	0.03	0.03	
	Efficiency	%	97.0	97.0	97.0	97.0	97.0	97.0	97.0	
	Lifetime	years	35	35	35	35	35	35	35	
Utility-scale Geothermal Heat	Capex	¥/kW$_{th}$	874 080	812 160	768 000	677 340	587 760	500 850	415 272	[42]
	Opex fix	¥/(kW$_{th}$ a)	31 920	29 659	28 046	24 735	21 464	18 290	15 165	
	Opex var	¥/kWh$_{th}$	0	0	0	0	0	0	0	
	Efficiency	%	97.0	97.0	97.0	97.0	97.0	97.0	97.0	
	CoP		10	10	10	10	10	10	10	
	Lifetime	years	22	22	22	22	22	22	22	
Individual Heat Pump	Capex	¥/kW$_{th}$	50 000	43 750	37 500	34 375	31 250	28 125	25 000	[38]
	Opex fix	¥/(kW$_{th}$ a)	1 000	875	750	688	625	563	500	
	Opex var	¥/kWh$_{th}$	0	0	0	0	0	0	0	
	CoP		4.7	4.9	5.0	5.1	5.2	5.4	5.4	
	Lifetime	years	15	15	15	15	15	15	15	
Individual NG Heating	Capex	¥/kW$_{th}$	96 000	96 000	96 000	96 000	96 000	96 000	96 000	[43]
	Opex fix	¥/(kW$_{th}$ a)	3 240	3 240	3 240	3 240	3 240	3 240	3 240	
	Opex var	¥/kWh$_{th}$	0	0	0	0	0	0	0	
	Efficiency	%	95.0	95.0	95.0	95.0	95.0	95.0	95.0	
	Lifetime	years	22	22	22	22	22	22	22	
Individual Oil Heating	Capex	¥/kW$_{th}$	52 800	52 800	52 800	52 800	52 800	52 800	52 800	[43]
	Opex fix	¥/(kW$_{th}$ a)	2 160	2 160	2 160	2 160	2 160	2 160	2 160	
	Opex var	¥/kWh$_{th}$	0	0	0	0	0	0	0	
	Efficiency	%	100	100	100	100	100	100	100	
	Lifetime	years	20	20	20	20	20	20	20	
Individual Biomass Heating	Capex	¥/kW$_{th}$	200 000	200 000	222 222	205 694	189 167	172 639	156 111	[43]
	Opex fix	¥/(kW$_{th}$ a)	593	593	658	609	560	512	463	
	Opex var	¥/kWh$_{th}$	0	0	0	0	0	0	0	
	Efficiency	%	100	100	100	100	100	100	100	
	Lifetime	years	20	20	20	20	20	20	20	
Individual Biogas Heating	Capex	¥/kW$_{th}$	192 000	192 000	192 000	186 000	180 000	174 000	168 000	[43]
	Opex fix	¥/(kW$_{th}$ a)	6 480	6 480	6 480	6 278	6 075	5 873	5 670	
	Opex var	¥/kWh$_{th}$	0	0	0	0	0	0	0	
	Efficiency	%	95	95	95	95	95	95	95	
	Lifetime	years	22	22	22	22	22	22	22	
Water Electrolysis	Capex	¥/kW$_{H2}$	98 640	72 000	54 720	44 850	39 072	33 642	29 760	[44] [45]
	Opex fix	¥/(kW$_{H2}$ a)	3 453	2 521	1 916	1 570	1 368	1 178	1 042	
	Opex var	¥/kWh$_{H2}$	0.2	0.1	0.1	0.1	0.1	0.1	0.1	
	Efficiency	%	82.2	82.2	82.2	82.2	82.2	82.2	82.2	
	Lifetime	years	30	30	30	30	30	30	30	

CO_2 direct air capture	Capex	¥/(t_{CO_2} a)	105 120	69 264	48 672	38 778	31 284	27 342	23 880	[46] [47]
	Opex fix	¥/(t_{CO_2} a)	4 205	2 771	1 947	1 551	1 251	1 094	955	
	Opex var	¥/t_{CO_2}	0	0	0	0	0	0	0	
	Electricity consumption	$kWh_{,el}/tCO_2$	250	237	225	213	202.5	192	182.25	
	Heat consumption	$kWh_{,th}/tCO_2$	1750	1618	1500	1387	1286	1189	1102	
	Lifetime	years	20	30	30	30	30	30	30	
Methanation	Capex	¥/kW_{SNG}	72 288	52 992	40 032	34 086	29 832	25 704	22 800	[44] [45]
	Opex fix	¥/(kW_{SNG} a)	3 325	2 437	1 841	1 568	1 372	1 182	1 049	
	Opex var	¥/kWh_{SNG}	0.2	0.2	0.1	0.1	0.1	0.1	0.1	
	Efficiency	%	77.8	77.8	77.8	77.8	77.8	77.8	77.8	
	CO_2 consumption	$kgCO_2$/ kWh_{SNG}	0.18	0.18	0.18	0.18	0.18	0.18	0.18	
	Lifetime	years	30	30	30	30	30	30	30	
Biogas digester	Capex	¥/kW_{th}	175 347	169 429	163 200	139 035	117 549	96 772	77 769	[48]
	Opex fix	¥/(kW_{th} a)	7 014	6 777	6 528	5 561	4 702	3 871	3 111	
	Opex var	¥/kWh_{th}	0	0	0	0	0	0	0	
	Efficiency	%	100	100	100	100	100	100	100	
	Lifetime	years	20	20	20	25	25	25	25	
Biogas Upgrade	Capex	¥/kW_{th}	69 600	64 800	60 000	48 990	40 920	33 390	26 400	[48]
	Opex fix	¥/(kW_{th} a)	5 568	5 184	4 800	3 919	3 274	2 671	2 112	
	Opex var	¥/kWh_{th}	0	0	0	0	0	0	0	
	Efficiency	%	98.0	98.0	98.0	98.0	98.0	98.0	98.0	
	Lifetime	years	20	20	20	20	20	20	20	
Fischer-Tropsch unit	Capex	¥/kW FT_{Liq}	136 368	136 368	136 368	130 686	112 504	107 390	102 276	[47]
	Opex fix	¥/kW FT_{Liq}	4 091	4 091	4 091	3 921	3 375	3 222	3 068	
	Opex var	¥/kWh FT_{Liq}	0	0	0	0	0	0	0	
	Lifetime	years	30	30	30	30	30	30	30	
	Opex fix	¥/kW_{Liq}	2 062	2 062	2 062	971	807	732	662	
	Opex var	¥/kWh_{Liq}	0	0	0	0	0	0	0	
	Efficiency	%	63.4	63.4	63.4	63.4	63.4	63.4	63.4	
	CO_2 consumption	$kgCO_2/kWh_{FT}$	0.28	0.28	0.28	0.28	0.28	0.28	0.28	
	Heat consumption	kWh,he/kWh, th	0.35	0.35	0.35	0.35	0.35	0.35	0.35	
	Lifetime	years	30	30	30	30	30	30	30	
Steam Methane Reforming	Capex	¥/kW_{H2}	46 080	46 080	46 080	44 160	42 240	40 320	38 400	[49]
	Opex fix	¥/kW_{H2}	2 304	2 304	2 304	2 208	2 112	2 016	1 920	
	Opex var	¥/kWh_{H2}	0	0	0	0	0	0	0	
	Efficiency	%	84.5	84.5	84.5	84.5	84.5	84.5	84.5	
	Lifetime	years	30	30	30	30	30	30	30	
Battery Storage	Capex	¥/kWh_{el}	28 080	18 360	13 200	10 680	9 120	8 160	7 320	[50] [51]
	Opex fix	¥/(kWh_{el} a)	394	312	264	246	228	212	205	
	Opex var	¥/kWh_{el}	0	0	0	0	0	0	0	
	Efficiency	%	91.0	92.0	93.0	94.0	95.0	95.0	95.0	
	Self-Discharge	[%/h]	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	20	20	20	

Battery Interface	Capex	¥/kW$_{el}$	14 040	9 120	6 600	5 280	4 440	3 960	3 600	[50] [51]
	Opex fix	¥/(kW$_{el}$ a)	197	155	132	121	112	103	101	
	Opex var	¥/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	20	20	20	
Battery PV pros residential Storage	Capex	¥/kWh$_{el}$	55 440	36 960	26 880	21 840	18 720	16 800	15 240	[50] [51]
	Opex fix	¥/(kWh$_{el}$ a)	610	480	403	371	337	336	305	
	Opex var	¥/kWh$_{el}$	0	0	0	0	0	0	0	
	Efficiency	%	91.0	92.0	93.0	94.0	95.0	95.0	95.0	
	Self-Discharge	[%/h]	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	20	20	20	
Battery PV pros residential Interface	Capex	¥/kW$_{el}$	27 720	18 360	13 440	10 800	9 120	8 160	7 440	[50] [51]
	Opex fix	¥/(kW$_{el}$ a)	305	239	202	184	164	163	149	
	Opex var	¥/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	20	20	20	
Battery PV pros commercial Storage	Capex	¥/kWh$_{el}$	43 920	28 800	21 000	16 920	14 520	12 960	11 760	[50] [51]
	Opex fix	¥/(kWh$_{el}$ a)	527	432	358	322	305	286	270	
	Opex var	¥/kWh$_{el}$	0	0	0	0	0	0	0	
	Efficiency	%	91.0	92.0	93.0	94.0	95.0	95.0	95.0	
	Self-Discharge	[%/h]	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	20	20	20	
Battery PV pros commercial Interface	Capex	¥/kW$_{el}$	21 960	14 280	10 560	8 400	7 080	6 360	5 760	[50] [51]
	Opex fix	¥/(kW$_{el}$ a)	264	215	180	160	149	140	132	
	Opex var	¥/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	20	20	20	
Battery PV pros industrial Storage	Capex	¥/kWh$_{el}$	33 360	21 720	15 720	12 600	10 800	9 600	8 640	[50] [51]
	Opex fix	¥/(kWh$_{el}$ a)	467	370	314	290	270	250	233	
	Opex var	¥/kWh$_{el}$	0	0	0	0	0	0	0	
	Efficiency	%	91.0	92.0	93.0	94.0	95.0	95.0	95.0	
	Self-Discharge	[%/h]	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	20	20	20	
Battery PV pros industrial Interface	Capex	¥/kW$_{el}$	16 680	10 800	7 920	6 240	5 280	4 680	4 200	[50] [51]
	Opex fix	¥/(kW$_{el}$ a)	234	184	158	144	132	121	114	
	Opex var	¥/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	20	20	20	
PHES Storage	Capex	¥/kWh$_{el}$	1 848	1 848	1 848	1 640	1 432	1 224	1 016	[51]
	Opex fix	¥/(kWh$_{el}$ a)	320	320	320	284	248	212	176	
	Opex var	¥/kWh$_{el}$	0	0	0	0	0	0	0	
	Efficiency	%	85.0	85.0	85.0	85.0	85.0	85.0	85.0	
	Self-Discharge	[%/h]	0	0	0	0	0	0	0	
	Lifetime	years	50	50	50	50	50	50	50	
PHES Interface	Capex	¥/kW$_{el}$	156 000	156 000	156 000	138 450	120 900	103 350	85 800	[51]
	Opex fix	¥/(kW$_{el}$ a)	0	0	0	0	0	0	0	
	Opex var	¥/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	50	50	50	50	50	50	50	

A-CAES Storage	Capex	¥/kWh$_{el}$	18 000	15 672	13 896	11 417	9 449	7 473	5 782	[38] [51]
	Opex fix	¥/(kWh$_{el}$ a)	278	238	209	173	143	113	87	
	Opex var	¥/kWh$_{el}$	0	0	0	0	0	0	0	
	Efficiency	%	59.3	64.7	70.0	70.0	70.0	70.0	70.0	
	Self-Discharge	[%/h]	0.1	0.1	0.1	0.1	0.1	0.1	0.1	
	Lifetime	years	40	40	40	40	40	40	40	
A-CAES Interface	Capex	¥/kW$_{el}$	129 600	129 600	129 600	115 020	100 440	85 860	71 280	[38] [51]
	Opex fix	¥/(kW$_{el}$ a)	4 200	4 200	4 200	3 728	3 255	2 783	2 310	
	Opex var	¥/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	40	40	40	40	40	40	40	
Hot Heat Storage Storage	Capex	¥/kWh$_{th}$	10 032	7 848	6 432	4 963	3 906	3 069	2 310	[51]
	Opex fix	¥/(kWh$_{th}$ a)	151	118	96	75	60	46	34	
	Opex var	¥/kWh$_{th}$	0	0	0	0	0	0	0	
	Efficiency	%	90.0	90.0	90.0	90.0	90.0	90.0	90.0	
	Self-Discharge	[%/h]	0.2	0.2	0.2	0.2	0.2	0.2	0.2	
	Lifetime	years	25	25	25	30	30	30	30	
Hot Heat Storage Interface	Capex	¥/kW$_{th}$	0	0	0	0	0	0	0	[51]
	Opex fix	¥/(kW$_{th}$ a)	0	0	0	0	0	0	0	
	Opex var	¥/kW$_{th}$	0	0	0	0	0	0	0	
	Lifetime	years	25	25	25	30	30	30	30	
Hydrogen Storage	Capex	¥/kWh$_{th}$	58	58	58	51	45	38	32	[52]
	Opex fix	¥/(kWh$_{th}$ a)	2	2	2	2	2	2	1	
	Opex var	¥/kWh$_{th}$	0	0	0	0	0	0	0	
	Efficiency	%	100	100	100	100	100	100	100	
	Self-Discharge	[%/h]	0	0	0	0	0	0	0	
	Lifetime	years	30	30	30	30	30	30	30	
Hydrogen Storage Interface	Capex	¥/kW$_{th}$	24 000	24 000	24 000	21 300	18 600	15 900	13 200	[52]
	Opex fix	¥/(kW$_{th}$ a)	960	960	960	852	744	636	528	
	Opex var	¥/kW$_{th}$	0	0	0	0	0	0	0	
	Lifetime	years	15	15	15	15	15	15	15	
CO_2 Storage	Capex	¥/ton	34 080	34 080	34 080	30 246	26 412	22 578	18 744	
	Opex fix	¥/(ton a)	2 386	2 386	2 386	2 117	1 849	1 580	1 312	
	Opex var	¥/ton	0	0	0	0	0	0	0	
	Efficiency	%	100	100	100	100	100	100	100	
	Self-Discharge	[%/h]	0	0	0	0	0	0	0	
	Lifetime	years	30	30	30	30	30	30	30	
CO_2 Storage Interface	Capex	¥/ton/h	0	0	0	0	0	0	0	
	Opex fix	¥/(ton/h a)	0	0	0	0	0	0	0	
	Opex var	¥/ton	0	0	0	0	0	0	0	
	Lifetime	years	50	50	50	50	50	50	50	
Gas Storage	Capex	¥/kWh$_{th}$	12	12	12	11	9	8	7	
	Opex fix	¥/(kWh$_{th}$ a)	0	0	0	0	0	0	0	
	Opex var	¥/kWh$_{th}$	0	0	0	0	0	0	0	
	Efficiency	%	100	100	100	100	100	100	100	

	Self-Discharge	[%/h]	0	0	0	0	0	0	0	
	Lifetime	years	50	50	50	50	50	50	50	
Gas Storage Interface	Capex	¥/kW$_{th}$	24 000	24 000	24 000	21 300	18 600	15 900	13 200	
	Opex fix	¥/(kW$_{th}$ a)	960	960	960	852	744	636	528	
	Opex var	¥/kW$_{th}$	0	0	0	0	0	0	0	
	Lifetime	years	15	15	15	15	15	15	15	
District Heat Storage	Capex	¥/kWh$_{th}$	9 600	7 200	7 200	5 325	3 720	3 180	2 640	
	Opex fix	¥/(kWh$_{th}$ a)	144	108	108	80	56	48	40	
	Opex var	¥/kWh$_{th}$	0	0	0	0	0	0	0	
	Efficiency	%	90.0	90.0	90.0	90.0	90.0	90.0	90.0	
	Self-Discharge	[%/h]	0.2	0.2	0.2	0.2	0.2	0.2	0.2	
	Lifetime	years	25	25	25	25	25	25	25	
District Heat Storage Interface	Capex	¥/kW$_{th}$	0	0	0	0	0	0	0	
	Opex fix	¥/(kW$_{th}$ a)	0	0	0	0	0	0	0	
	Opex var	¥/kW$_{th}$	0	0	0	0	0	0	0	
	Lifetime	years	25	25	25	25	25	25	25	
HVDC (land line)	Capex	¥/(kW·km)	420	420	420	381	343	304	265	[53]
	Opex fix	¥/(kW·km a)	8.4	8.4	8.4	7.4	6.3	5.3	4.3	
	Opex var	¥/kWh$_{el}$	0	0	0	0	0	0	0	
	Loss	%/1000km	1.6	1.6	1.6	1.6	1.6	1.6	1.6	
	Lifetime	years	35	35	35	35	35	35	35	
HVDC (sea cable)	Capex	¥/(kW·km)	147	147	147	139	132	125	118	[54]
	Opex fix	¥/(kW·km a)	2.9	2.9	2.9	2.6	2.2	1.9	1.5	
	Opex var	¥/kWh$_{el}$	0	0	0	0	0	0	0	
	Loss	%/1000km	1.6	1.6	1.6	1.6	1.6	1.6	1.6	
	Lifetime	years	35	35	35	35	35	35	35	
HVDC converter station pair	Capex	¥/(kW·km)	25 120	25 120	25 120	24 230	23 340	22 450	21 560	[53]
	Opex fix	¥/(kW·km a)	251	251	251	242	233	225	216	
	Opex var	¥/kWh$_{el}$	0	0	0	0	0	0	0	
	Loss	%	1.4	1.4	1.4	1.4	1.4	1.4	1.4	
	Lifetime	years	35	35	35	35	35	35	35	
HVAC	Capex	¥/(kW·km)	190	190	190	173	156	139	123	[53]
	Opex fix	¥/(kW·km a)	1.2	1.2	1.2	1.1	1.0	0.9	0.8	
	Opex var	¥/kWh$_{el}$	0	0	0	0	0	0	0	
	Loss	%/1000km	9.4	9.4	9.4	9.4	9.4	9.4	9.4	
	Lifetime	years	35	35	35	35	35	35	35	

Table A 2*: Financial assumptions for the fossil, nuclear fuels and biomass feedstock.*

Name of component	Unit	2020	2025	2030	2035	2040	2045	2050	References
Coal	¥/kWh$_{th}$	0.96	0.92	0.92	0.89	0.89	0.89	0.96	[55]
Fuel oil	¥/kWh$_{th}$	3.84	3.47	3.46	3.46	3.45	3.45	3.84	[55]
Fossil gas	¥/kWh$_{th}$	3.64	3.48	3.53	3.15	3.08	3.06	3.64	[55]
Uranium	¥/kWh$_{th}$	0.31	0.31	0.31	0.31	0.31	0.31	0.31	[56]
Biomass	¥/kWh$_{th}$	4.9	4.9	4.9	4.9	4.9	4.9	4.9	[19]

***Table A 3**: Carbon pricing.*

Scenario	Unit	2020	2025	2030	2035	2040	2045	2050
Base Policy Scenario	¥/tCO_2	265	2 057	5 038	6 417	8 250	11 000	16 500
Delayed Policy Scenario	¥/tCO_2	265	1 029	2 519	3 208	4 125	5 500	8 250

***Table A 4**: Sustainable electricity and e-fuels imports cost assumptions.*

		2035	2040	2045	2050
Electricity imports from Russia					
Connection length: Ishikari - Korsakov sea cable: 450km, Korsakov - Sov. Gavan' sea cable 480km, Sov.Gavan' – Khabarovsk landline 434km					
Grid connection capacity: Russia	GW	2	6	10	10
Estimated import cost: Ishikari	¥/MWh	6 432	6 336	5 952	5 856
Electricity imports from Northeast China					
Connection length: Matsue - Busan sea cable 370 km, Busan - Incheon landline 374km, Incheon - Rongcheng sea cable 380km, Rongcheng - Tianjin sea cable 520km, Tianjin - Beijing landline 160km					
Grid connection capacity: China	GW	2	6	10	10
Estimated import cost: Matsue	¥/MWh	6 936	6 852	6 516	6 324
E-fuels imports from West Australia					
Green LH_2	¥/MWh	9 935	8 964	8 964	6 891
production cost	¥/MWh	7 729	6 804	6 804	4 830
transport cost	¥/MWh	1 800	1 800	1 800	1 800
import margin	¥/MWh	406	360	360	261
Green LNG	¥/MWh	13 632	12 217	12 217	9 381
production cost	¥/MWh	11 250	9 902	9 902	7 201
transport cost	¥/MWh	1 800	1 800	1 800	1 800
import margin	¥/MWh	582	515	515	380
FT fuels (synthetic liquid fuels)	¥/MWh	15 523	13 367	13 367	9 504
production cost	¥/MWh	14 604	12 550	12 550	8 871
transport cost	¥/MWh	180	180	180	180
import margin	¥/MWh	739	637	637	453

***Table A 5**: Power consumption for general application in TWh.*

Region	2020	2025	2030	2035	2040	2045	2050
Hokkaido	25.1	24.2	23.3	22.4	21.6	20.8	20.1
Tohoku	61.5	59.3	57.1	55.0	53.0	51.1	49.2
Tokyo	269.4	259.6	250.1	241.0	232.2	223.7	215.6
Hokuriku	22.8	22.0	21.2	20.4	19.6	18.9	18.2
Chubu	86.1	83.0	80.0	77.1	74.2	71.5	68.9
Kansai	116.1	111.9	107.8	103.9	100.1	96.4	92.9
Chugoku	53.3	51.3	49.4	47.6	45.9	44.2	42.6
Shikoku	23.8	22.9	22.1	21.3	20.5	19.8	19.1
Kyushu	75.8	73.1	70.4	67.8	65.4	63.0	60.7
Japan total	**733.9**	**707.2**	**681.4**	**656.5**	**632.6**	**609.5**	**587.3**

Table A 6: *Power consumption for cooling applications in TWh.*

Region	2020	2025	2030	2035	2040	2045	2050
Hokkaido	2.3	2.3	2.2	2.2	2.2	2.2	2.2
Tohoku	5.6	5.5	5.5	5.4	5.4	5.3	5.3
Tokyo	24.6	24.3	24.1	23.8	23.6	23.4	23.1
Hokuriku	2.1	2.1	2.0	2.0	2.0	2.0	2.0
Chubu	7.9	7.8	7.7	7.6	7.5	7.5	7.4
Kansai	10.6	10.5	10.4	10.3	10.2	10.1	10.0
Chugoku	4.9	4.8	4.8	4.7	4.7	4.6	4.6
Shikoku	2.2	2.1	2.1	2.1	2.1	2.1	2.0
Kyushu	6.9	6.8	6.8	6.7	6.6	6.6	6.5
Japan total	**66.9**	**66.2**	**65.6**	**64.9**	**64.3**	**63.6**	**63.0**

Table A 7: *Space heating demand in TWh.*

Region	2020	2025	2030	2035	2040	2045	2050
Hokkaido	15.9	15.3	14.8	14.2	13.7	13.2	12.7
Tohoku	27.7	26.7	25.7	24.8	23.9	23.0	22.1
Tokyo	111.1	107.1	103.2	99.4	95.8	92.3	88.9
Hokuriku	7.0	6.8	6.5	6.3	6.1	5.8	5.6
Chubu	38.2	36.8	35.5	34.2	32.9	31.7	30.6
Kansai	49.0	47.2	45.5	43.8	42.2	40.7	39.2
Chugoku	41.9	40.3	38.9	37.5	36.1	34.8	33.5
Shikoku	12.4	11.9	11.5	11.1	10.7	10.3	9.9
Kyushu	33.9	32.7	31.5	30.3	29.2	28.2	27.1
Japan total	**337.1**	**324.8**	**313.0**	**301.6**	**290.6**	**280.0**	**269.8**

Table A 8: *Domestic water heating and cooking demand in TWh.*

Region	2020	2025	2030	2035	2040	2045	2050
Hokkaido	19.7	19.0	18.3	17.6	17.0	16.3	15.7
Tohoku	34.2	33.0	31.8	30.6	29.5	28.4	27.4
Tokyo	137.5	132.5	127.6	123.0	118.5	114.2	110.0
Hokuriku	8.7	8.4	8.1	7.8	7.5	7.2	6.9
Chubu	47.3	45.5	43.9	42.3	40.7	39.3	37.8
Kansai	60.6	58.4	56.3	54.2	52.2	50.3	48.5
Chugoku	51.8	49.9	48.1	46.3	44.7	43.0	41.5
Shikoku	15.3	14.8	14.2	13.7	13.2	12.7	12.3
Kyushu	42.0	40.4	39.0	37.5	36.2	34.9	33.6
Japan total	**417.1**	**401.9**	**387.2**	**373.1**	**359.5**	**346.4**	**333.8**

***Table A 9**: Industrial heat demand in TWh.*

Region	2020	2025	2030	2035	2040	2045	2050
Hokkaido	83.9	79.1	74.5	70.2	66.2	62.4	58.8
Tohoku	129.8	122.3	115.3	108.6	102.4	96.5	90.9
Tokyo	500.9	472.1	444.9	419.2	395.1	372.3	350.9
Hokuriku	26.4	24.9	23.4	22.1	20.8	19.6	18.5
Chubu	178.1	167.9	158.2	149.1	140.5	132.4	124.8
Kansai	223.3	210.4	198.3	186.9	176.1	165.9	156.4
Chugoku	232.6	219.2	206.6	194.7	183.5	172.9	162.9
Shikoku	61.5	58.0	54.6	51.5	48.5	45.7	43.1
Kyushu	158.7	149.6	141.0	132.9	125.2	118.0	111.2
Japan total	**1 595.4**	**1 503.5**	**1 416.8**	**1 335.2**	**1 258.2**	**1 185.7**	**1 117.4**

***Table A 10**: Power losses in transmission and distribution grids.*

	2020	2025	2030	2035	2040	2045	2050	Reference
Losses (%)	4.0	4.0	4.0	3.9	3.9	3.8	3.7	[23,24]

***Table A 11**: Transportation demand for LDV (million p-km).*

Region	2020	2025	2030	2035	2040	2045	2050
Hokkaido	34 571	34 150	33 731	32 194	30 656	29 118	27 580
Tohoku	71 948	71 072	70 200	67 000	63 799	60 599	57 399
Tokyo	296 896	293 279	289 684	276 477	263 271	250 064	23 6857
Hokuriku	19 404	19 168	18 933	18 070	17 207	16 343	15 480
Chubu	103 511	102 250	100 996	96 392	91 787	87 183	82 579
Kansai	134 557	132 918	131 288	125 303	119 317	113 332	107 346
Chugoku	47 904	47 320	46 740	44 610	42 479	40 348	38 217
Shikoku	24 563	24 264	23 967	22 874	21 781	20 689	19 596
Kyushu	84 126	83 102	82 083	78 341	74 599	70 856	67 114
Japan total	**817 480**	**807 522**	**797 623**	**761 260**	**72 4896**	**688 532**	**652 168**

***Table A 12**: Transportation demand for Bus (million p-km).*

Region	2020	2025	2030	2035	2040	2045	2050
Hokkaido	3 435	3 496	3 555	3 587	3 619	3 650	3 682
Tohoku	7 149	7 275	7 399	7 465	7 531	7 597	7 663
Tokyo	29 499	30 022	30 533	30 805	31 078	31 350	31 622
Hokuriku	1 928	1 962	1 996	2 013	2 031	2 049	2 067
Chubu	10 285	10 467	10 645	10 740	10 835	10 930	11 025
Kansai	13 369	13 606	13 838	13 961	14 085	14 208	14 331
Chugoku	4 760	4 844	4 927	4 970	5 014	5 058	5 102
Shikoku	2 441	2 484	2 526	2 549	2 571	2 594	2 616
Kyushu	8 359	8 507	8 652	8 729	8 806	8 883	8 960
Japan total	**81 224**	**82 662**	**84 071**	**84 820**	**85 570**	**86 319**	**87 069**

***Table A 13**: Transportation demand for MDV (million t-km).*

Region	2020	2025	2030	2035	2040	2045	2050
Hokkaido	8 355	8 736	9 103	8 723	8 344	7 965	7 586
Tohoku	17 387	18 182	18 944	18 155	17 366	16 577	15 788
Tokyo	71 749	75 027	78 172	74 917	71 662	68 407	65 151
Hokuriku	4 689	4 904	5 109	4 896	4 684	4 471	4 258
Chubu	25 015	26 158	27 254	26 119	24 984	23 849	22 715
Kansai	32 518	34 003	35 429	33 953	32 478	3 1003	29 527
Chugoku	11 577	12 106	12 613	12 088	11 563	11 037	10 512
Shikoku	5 936	6 207	6 467	6 198	5 929	5 660	5 390
Kyushu	20 330	21 259	22 150	21 228	20 306	19 383	18 461
Japan total	**197 556**	**206 582**	**215 242**	**206 279**	**197 315**	**188 352**	**179 389**

***Table A 14**: Transportation demand for HDV (million t-km).*

Region	2020	2025	2030	2035	2040	2045	2050
Hokkaido	1 591	1 664	1 734	1 662	1 589	1 517	1 445
Tohoku	3 312	3 463	3 608	3 458	3 308	3 158	3 007
Tokyo	13 666	14 291	14 890	14 270	13 650	13 030	12 410
Hokuriku	893	934	973	933	892	852	811
Chubu	47 65	4 982	5 191	4 975	4 759	4 543	4 327
Kansai	6 194	6 477	6 748	6 467	6 186	5 905	5 624
Chugoku	2 205	2 306	2 402	2 302	2 202	2 102	2 002
Shikoku	1 131	1 182	1 232	1 181	1 129	1 078	1 027
Kyushu	3 872	4 049	4 219	4 043	3 868	3 692	3 516
Japan total	**37 630**	**39 349**	**40 998**	**39 291**	**37 584**	**35 877**	**34 169**

***Table A 15**: Transportation demand for Rail passenger and freight.*

Transportation demand for Rail passenger (million p-km)							
Region	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Hokkaido	18 520	18 472	18 422	17 917	17 412	16 907	16 402
Tohoku	38 542	38 442	38 339	37 288	36 237	35 186	34 135
Tokyo	159 047	158 633	158 209	153 872	149 535	145 198	140 861
Hokuriku	10 395	10 368	10 340	10 057	9 773	9 490	9 206
Chubu	55 451	55 306	55 158	53 646	52 134	50 622	49 110
Kansai	72 082	71 894	71 702	69 736	67 771	65 805	63 840
Chugoku	25 662	25 595	25 527	24 827	24 127	23 428	22 728
Shikoku	13 158	13 124	13 089	12 730	12 372	12 013	11 654
Kyushu	45 066	44 949	44 829	43 600	42 371	41 142	39 913
Japan total	**437 923**	**436 784**	**435 616**	**423 674**	**411 733**	**399 791**	**387 850**
Transportation demand for Rail freight (million t-km)							
Region	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Hokkaido	1 019	1 108	1 201	1 169	1 138	1 107	1 075
Tohoku	2 121	2 307	2 499	2 434	2 369	2 303	2 238
Tokyo	8 750	9 518	10 312	10 043	9 774	9 505	9 236

Hokuriku	572	622	674	656	639	621	604
Chubu	3 051	3 318	3 595	3 501	3 408	3 314	3 220
Kansai	3 966	4 314	4 674	4 552	4 430	4 308	4 186
Chugoku	1 412	1 536	1 664	1 620	1 577	1 534	1 490
Shikoku	724	787	853	831	809	786	764
Kyushu	2 479	2 697	2 922	2 846	2 770	2 693	2 617
Japan total	**24 094**	**26 208**	**28 394**	**27 653**	**26 912**	**26 171**	**25 430**

Table A 16: *Transportation demand for Maritime transport passenger and freight.*

Transportation demand for Maritime transport passenger (million p-km)							
Region	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Hokkaido	105	104	103	99	96	92	88
Tohoku	189	188	187	180	173	166	160
Tokyo	169	168	167	161	155	149	143
Hokuriku	10	10	10	9	9	9	8
Chubu	174	173	172	166	159	153	147
Kansai	277	275	273	263	253	243	233
Chugoku	798	792	786	758	730	701	673
Shikoku	405	402	399	385	371	356	342
Kyushu	1 158	1 150	1 142	1 101	1 059	1 018	977
Japan total	**3 286**	**3 262**	**3 238**	**3 121**	**3 004**	**2 888**	**2 771**
Transportation demand for Maritime transport freight (million t-km)							
Region	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Hokkaido	15 250	16 428	17 632	17 081	16 530	15 980	15 429
Tohoku	14 166	15 260	16 379	15 867	15 355	14 843	14 332
Tokyo	44 413	47 842	51 350	49 746	48 141	46 536	44 932
Hokuriku	2 308	2 487	2 669	2 586	2 502	2 419	2 335
Chubu	23 869	25 712	27 598	26 735	25 873	25 011	24 148
Kansai	28 977	31 214	33 503	32 456	31 410	30 363	29 316
Chugoku	24 672	26 577	28 526	27 634	26 743	25 852	24 960
Shikoku	12 223	13 167	14 133	13 691	13 249	12 808	12 366
Kyushu	36 537	39 357	42 243	40 923	39 603	38 283	36 963
Japan total	**202 417**	**218 042**	**234 032**	**226 720**	**219 407**	**212 094**	**204 781**

Table A 17: *Transportation demand for Aviation passenger and freight.*

Transportation demand for Aviation passenger (million p-km)							
Region	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Hokkaido	8 997	8 932	8 867	8 547	8 227	7 907	7 587
Tohoku	2 494	2 476	2 458	2 369	2 281	2 192	2 103
Tokyo	42 079	41 775	41 471	39 973	38 476	36 979	35 482
Hokuriku	239	238	236	227	219	210	202
Chubu	4 474	4 441	4 409	4 250	4 091	3 931	3 772
Kansai	15 844	15 729	15 615	15 051	14 487	13 924	13 360
Chugoku	2423	2 406	2 388	2 302	2 216	2 130	2 043
Shikoku	2 573	2 554	2 536	2 444	2 353	2 261	2 170

Kyushu	15 018	14 910	14 801	14 267	13 732	13 198	12 664
Japan total	**94 141**	**93 461**	**92 780**	**89 431**	**86 082**	**82 732**	**79 383**
Transportation demand for Aviation freight (million t-km)							
Region	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Hokkaido	50	53	56	54	52	50	48
Tohoku	3	3	3	3	3	3	2
Tokyo	826	877	927	894	860	827	794
Hokuriku	0	0	0	0	0	0	0
Chubu	51	54	57	55	53	51	49
Kansai	225	239	253	243	234	225	216
Chugoku	7	7	8	7	7	7	6
Shikoku	5	5	5	5	5	5	5
Kyushu	81	86	91	87	84	81	78
Japan total	**1 246**	**1 323**	**1 399**	**1 349**	**1 298**	**1 248**	**1 197**

***Table A 18**: Share of different fuel types for LDV*

	2020		**2025**		**2030**		**2035**		**2040**		**2045**		**2050**	
	BPS	**DPS**	**BPS**	**DPS**	**BPS**	**DPS**	**BPS**	**DPS**	**BPS**	**DPS**	**BPS**	**DPS**	**BPS**	**DPS**
BEV	3%	3%	10%	7%	39%	10%	68%	25%	74%	40%	73%	55%	76%	70%
PHEV	3%	3%	10%	7%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
FCEV	0%	0%	0%	1%	1%	1%	2%	1%	5%	1%	10%	0%	10%	0%
ICE	94%	94%	80%	87%	50%	79%	20%	64%	11%	50%	7%	35%	4%	20%

***Table A 19**: Share of different fuel types for Bus*

	2020		**2025**		**2030**		**2035**		**2040**		**2045**		**2050**	
	BPS	**DPS**	**BPS**	**DPS**	**BPS**	**DPS**	**BPS**	**DPS**	**BPS**	**DPS**	**BPS**	**DPS**	**BPS**	**DPS**
BEV	20%	20%	50%	20%	80%	20%	90%	31%	90%	41%	90%	52%	90%	62%
PHEV	1%	1%	2%	3%	3%	5%	4%	6%	5%	8%	6%	9%	7%	10%
FCEV	0%	0%	0%	0%	0%	0%	0%	2%	0%	4%	0%	6%	0%	8%
ICE	79%	79 %	48%	77 %	17%	75 %	6%	61 %	5%	47 %	4%	34 %	3%	20 %

***Table A 20**: Share of different fuel types for MDV*

	2020		**2025**		**2030**		**2035**		**2040**		**2045**		**2050**	
	BPS	**DPS**	**BPS**	**DPS**	**BPS**	**DPS**	**BPS**	**DPS**	**BPS**	**DPS**	**BPS**	**DPS**	**BPS**	**DPS**
BEV	10%	10%	19%	10%	48%	10%	75%	21%	80%	32%	80%	43%	80%	54%
PHEV	1%	1%	2%	6%	3%	10%	4%	10%	5%	10%	6%	10%	7%	10%
FCEV	0%	0%	1%	1%	2%	2%	5%	5%	10%	9%	10%	12%	10%	16%
ICE	89%	89%	78%	84%	47%	79%	16%	64%	5%	49%	4%	35%	3%	20%

Table A 21: *Share of different fuel types for HDV*

	2020		2025		2030		2035		2040		2045		2050	
	BPS	**DPS**	**BPS**	**DPS**	**BPS**	**DPS**	**BPS**	**DPS**	**BPS**	**DPS**	**BPS**	**DPS**	**BPS**	**DPS**
BEV	1%	1%	8%	3%	15%	5%	30%	17%	50%	30%	50%	42%	50%	54%
PHEV	1%	1%	2%	3%	3%	5%	4%	6%	8%	8%	16%	9%	17%	10%
FCEV	1%	1%	2%	1%	5%	2%	20%	5%	30%	9%	30%	12%	30%	16%
ICE	98%	98%	88%	93%	77%	89%	46%	71%	12%	54%	4%	37%	3%	20%

Table A 22: *Specific fuel consumption for all transport modes and all fuel types.*

Transport mode	Unit	2020	2025	2030	2035	2040	2045	2050
LDV ICE	$kWh,_{th}/km$	0.689	0.633	0.569	0.520	0.480	0.408	0.336
LDV BEV	$kWh,_{el}/km$	0.127	0.114	0.101	0.094	0.087	0.080	0.074
LDV FCEV	$kWh,_{H2}/km$	0.269	0.226	0.217	0.200	0.200	0.165	0.156
LDV PHEV	$kWh,_{th}/km$	0.187	0.151	0.136	0.124	0.115	0.097	0.080
LDV PHEV	$kWh,_{el}/km$	0.124	0.115	0.102	0.095	0.088	0.081	0.075
BUS ICE	$kWh,_{th}/km$	3.008	2.958	2.908	2.860	2.812	2.766	2.720
BUS BEV	$kWh,_{el}/km$	0.886	0.855	0.823	0.794	0.766	0.739	0.713
BUS FCEV	$kWh,_{H2}/km$	2.987	2.853	2.720	2.598	2.482	2.371	2.265
BUS PHEV	$kWh,_{th}/km$	2.012	1.918	1.945	1.913	1.881	1.850	1.819
BUS PHEV	$kWh,_{el}/km$	0.904	0.872	0.840	0.810	0.782	0.754	0.727
MDV ICE	$kWh,_{th}/km$	1.592	1.504	1.419	1.335	1.260	1.182	1.102
MDV BEV	$kWh,_{el}/km$	0.430	0.384	0.344	0.318	0.294	0.272	0.252
MDV FCEV	$kWh,_{H2}/km$	1.362	1.286	1.214	1.142	1.078	1.011	0.943
MDV PHEV	$kWh,_{th}/km$	1.362	1.286	1.214	1.142	1.078	1.011	0.943
MDV PHEV	$kWh,_{el}/km$	0.334	0.299	0.267	0.247	0.229	0.212	0.196
HDV ICE	$kWh,_{th}/km$	3.253	3.009	2.784	2.571	2.378	2.192	2.013
HDV BEV	$kWh,_{el}/km$	1.671	1.494	1.336	1.236	1.144	1.058	0.979
HDV FCEV	$kWh,_{H2}/km$	1.952	1.805	1.670	1.543	1.427	1.315	1.208
HDV PHEV	$kWh,_{th}/km$	2.277	2.106	1.949	1.800	1.664	1.534	1.409
HDV PHEV	$kWh,_{el}/km$	0.501	0.448	0.401	0.371	0.343	0.318	0.294
Rail passenger electrical	$kWh,_{el}/p*km$	0.051	0.049	0.047	0.045	0.043	0.041	0.039
Rail freight electrical	$kWh,_{el}/t*km$	0.063	0.059	0.055	0.051	0.047	0.043	0.039
Maritime transport passenger liquid fuel	$kWh,_{th}/p*km$	0.534	0.515	0.496	0.491	0.486	0.481	0.476
Maritime transport freight liquid fuel	$kWh,_{th}/t*km$	0.126	0.121	0.117	0.116	0.115	0.113	0.112
Aviation passenger liquid fuel	$kWh,_{th}/p*km$	0.530	0.503	0.478	0.453	0.431	0.408	0.387
Aviation freight liquid fuel	$kWh,_{th}/t*km$	4.934	4.679	4.444	4.220	4.006	3.802	3.609

Table A 23: *Share of BEV and PHEV vehicles with enabled V2G.*

	2020	2025	2030	2035	2040	2045	2050
LDV	0%	2%	4%	6%	8%	12%	16%
BUS	0%	0%	0%	0%	0%	0%	0%
MDV	0%	2%	4%	6%	8%	12%	16%
HDV	0%	0%	0%	0%	0%	0%	0%

***Table A 24**: Renewable energy potential.*

Region	PV FLh [h]	Onshore Wind FLh [h]	Offshore Wind FLh [h]	Hydro power FLh [h]	Geothermal heat [TWh/a]	Biomass residues [TWh/a]	Industrial biowastes [TWh/a]	Biogas [TWh/a]	MSW [TWh/a]
Hokkaido	1 264	3 042	4 406	3 845	26.6	7.6	3.6	2.0	1.6
Tohoku	1 256	2 877	4 104	3 196	182.5	14.8	7.4	1.7	3.3
Tokyo	1 382	2 096	4 628	1 139	32.4	8.0	30.6	2.0	13.7
Hokuriku	1 232	2 793	4 039	3 248	0.9	2.6	10.7	0.3	4.8
Chubu	1 373	2 156	4 337	3 465	8.1	4.1	2.0	0.6	0.9
Kansai	1 334	2 788	4 020	4 735	0.0	3.3	13.9	0.7	6.2
Chugoku	1 345	2 953	3 702	3 646	0.0	3.5	4.9	0.7	2.2
Shikoku	1 342	1 451	4 036	3 240	0.0	1.8	2.5	0.3	1.1
Kyushu	1 393	2 924	4 198	2 569	79.5	5.8	8.7	3.9	3.9
Japan total	**-**	**-**	**-**	**-**	**330.1**	**51.5**	**84.3**	**12.2**	**37.8**

How do we accomplish the clean-energy transition?

Agora Energiewende develops scientifically based and politically feasible approaches for ensuring successful energy transition in Germany, Europe and worldwide. We see ourselves as a think-tank and policy laboratory, centered around dialogue with energy policy stakeholders. Together with participants from public policy, civil society, business and academia, we develop a common understanding of energy transitions, its challenges and courses of action.

Renewable Energy Institute was established in the aftermath of Fukushima Nuclear Accident, in August 2011, to establish renewable energy based society in Japan and other countries. REI conducts scientific studies on renewable energy policies, advocates the policy makers and introduces global knowledges of renewables to the public.

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