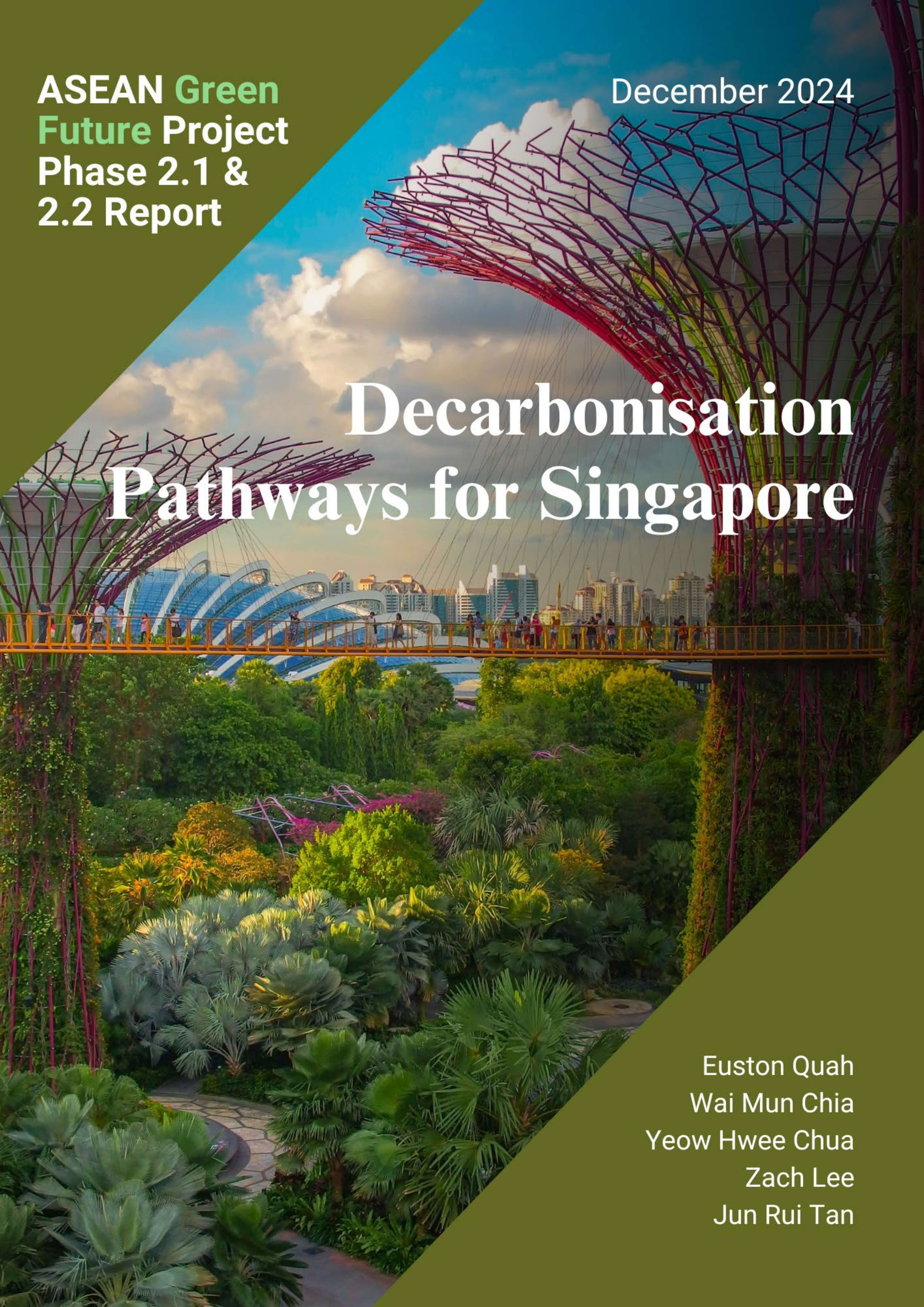
ASEAN Green Future Project Phase 2.1 & 2.2 Report

December 2024

# Decarbonisation Pathways for Singapore

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## About ASEAN Green Future

ASEAN Green Future is a multi-year regional research project that involves the UN Sustainable Development Solutions Network (SDSN), Climateworks Centre and nine country teams from leading universities and think tanks across Southeast Asia (Cambodia, Indonesia, Lao PDR, Malaysia, Myanmar, Philippines, Singapore, Thailand and Vietnam). The researchers undertake quantitative and qualitative climate policy analysis and develop net zero pathways to inform policy recommendations and support the strategic foresight of policy makers.

The Phase 1 country reports present priorities and actions to date, and key technology and policy opportunities to further advance domestic climate action. The Phase 1 regional report positions Southeast Asia's low carbon transition pathways within a global context using the country reports and other studies. This series of reports, produced through a synthesis of existing research and knowledge, builds the case for advancing the region's climate agenda. Phase 2 of the ASEAN Green Future project uses modelling to quantitatively assess the different decarbonisation pathways for Southeast Asia.

# Acknowledgements

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The authors gratefully acknowledge the valuable input and feedback provided by our expert reviewers: Dr Goh Chun Meng (UN Sustainable Development Solutions Network, Asia Headquarters, Sunway University), who reviewed the integrated Phase 2.1 and 2.2 report; Muhammad Rizki Kresnawan (Climateworks Centre) and Tan Siaw Woan (Khazanah Nasional Berhad), who reviewed the Phase 2.1 report. The authors extend their sincere appreciation to the Energy Market Authority, National Environment Agency, Land Transport Authority and The Straits Times of Singapore, among other institutions and agencies, for their useful resources available online that guided us on the policies modelled and data inputs in this report. We also thank Lui Yu Sen, Mei Juntao and Zhang He, former students at Nanyang Technological University, for their kind assistance in data collection.


# Disclaimer



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# ACRONYMS

| | |
|---|---|
| AEC | ASEAN Centre for Energy |
| APERC | Asia Pacific Energy Research Centre (APERC) |
| ATB | Annual Technology Baseline |
| BAS | Baseline |
| BAU | Business-As-Usual |
| BESS | Battery Energy Storage Solutions |
| CCGT | Combined Cycle Gas Turbines |
| CCS | Carbon Capture and Storage |
| CNG | Compressed Natural Gas |
| EMA | Energy Market Authority |
| GW | Gigawatts |
| GWh | Gigawatt-hour |
| HA | Highly Ambitious |
| HDV | Heavy Duty Vehicle |
| IEA | International Energy Agency |
| IWMF | Tuas Nexus Integrated Waste Management Facility |
| KWh | Kilowatt-hour |
| LDV | Light Duty Vehicle |
| LEAP | Low Emissions Analysis Platform |
| LNG | Liquified Natural Gas |
| LPG | Liquified Petroleum Gas |
| LTA | Land Transport Authority |
| LTMS-PIP | Lao PDR-Thailand-Malaysia-Singapore Power Integration Project |
| MEPS | Minimum Energy Performance Standards |
| MJ | Megajoules |
| MSW | Municipal Solid Waste |
| $MtCO_2e/kgCO_2e$ | Million Tonne/Kilogram of Carbon Dioxide Equivalent |
| MTI | Ministry of Trade and Industry |
| MW | Megawatts |
| MWh | Megawatt-hour |
| NEA | National Environment Agency |
| OCGT | Open Cycle Gas Turbines |
| PJ | Petajoules |
| Pkm | Passenger-kilometres |
| PP | Power Plant |
| PPP | Purchasing Price Parity |
| RPS | Renewable Portfolio Standard |
| SCDF | Singapore Civil Defence Force |
| SEI | Stockholm Environment Institute |
| SES | Singapore Energy Statistics |
| SMR | Small Modular Reactor |
| ST | (Power) Station |
| TWh | Terawatt-hour |
| Tkm | Tonne-kilometres |
| TMUC | Tembusu Multi-Utilities Complex |
| VES | Vehicular Emissions Scheme |
| VLSFO | Very Low Sulphur Fuel Oil |
| WTE | Waste-to-Energy |

# 1. INTRODUCTION TO SINGAPORE

Addressing the challenges of climate change has consistently been among Singapore's top priorities. While initially committed to a 36% reduction in emission intensity (from 2005 levels) by 2030 in its intended Nationally Determined Contributions (NDC) to the United Nations Framework Convention on Climate Change, Singapore has continuously refined its strategies to adapt to evolving challenges and aspirations. In 2020, Singapore updated its climate goals, shifting from intensity targets to setting a specific emissions limit of 65 million tonnes of carbon dioxide equivalent ($MtCO_2e$) by around 2030. This was further integrated in Singapore's Long-Term Low-Emissions Development Strategy (LEDS), aiming to cut emissions by half to 33 $MtCO_2e$ by 2050. Then, in 2022, Singapore revised its targets again, aiming to reduce emissions to about 60 $MtCO_2e$ by 2030 after reaching peak emissions earlier, with the ultimate aim of achieving net zero emissions by 2050.

To achieve these goals, there is a need to have a comprehensive and integrated approach. One crucial strategy is outlined in the Singapore Green Plan 2030. This plan includes initiatives targeting green spaces, enhancing household resource efficiency, promoting cleaner transportation and transitioning to a greener energy mix. In order to foster a green economy, all economic players would need to work collaboratively towards these objectives. While the government of Singapore can take the lead in facilitating this transition, industries and individuals need to contribute through their own actions. Due to the interconnected nature of climate change impacts, addressing this global challenge requires concerted efforts from all sectors of society. This is best illustrated in the power sector.

In this study, we focus on an important aspect, the power sector. The power sector is critical as it is the foundational pillar of the entire economy's transition to a net zero economy. Moreover, there is the presence of the energy trilemma, highlighting the need to balance environmental sustainability, energy reliability and affordability. This underscores the significance of conducting a comprehensive study within the region. Through this study, we aim to assess potential pathways to decarbonising Singapore's power sector within the ASEAN Green Future project. Currently, the 2050 Energy Committee Report by the Energy Market Authority (EMA) has described a set of potential scenarios through which Singapore could achieve net-zero emissions in the power sector by 2050 (EMA, 2022a). We add on to the discussion by examining different pathways and linkages within the region.

Through the Low Emissions Analysis Platform (LEAP), we model historical and projected domestic energy demand and supply data[1], which includes the current green trajectory and the exploration of future developments in low-carbon alternatives such as hydrogen, geothermal and nuclear, as well as pushing the boundaries of solar energy deployment. Regarding the more ambitious pathways, we also examine greater interconnectivity of the regional renewable power grid and the potential phasing out of fossil fuels.

First, we focus on the rules-based simulation of a cleaner energy portfolio and decarbonisation pathways for Singapore, where the user defines prioritisation rules. Second, we focus on optimisation frameworks which taps on LEAP's capabilities to calculate the least-cost expansion and dispatch of power plants for an electric system.

[1] All energy usage pertaining to international activities (flights/freights) are omitted at this stage.

We would like to underscore that the simulations and optimisations are hypothetical and serve as an academic exercise which do not necessarily reflect our position on the best way to achieve net zero. The goal of this paper is to explore different possibilities that can facilitate policy discussions. As such, we clearly lay out all definitions and assumptions used.

# 2. SINGAPORE'S ENERGY SUPPLY PROFILE

Singapore faces several challenges in its energy landscape. Due to limited alternative energy resources, the nation has historically relied heavily on imported fossil fuels to meet its escalating energy demands. Nonetheless, it is acknowledged that this continued dependence on fossil fuels poses environmental risks and undermines long-term sustainability goals. Coupled with the energy trilemma of sustainability, energy security, and affordability, Singapore has recognised the need to invest in renewable energy sources and diversify its energy mix to avoid over-reliance on any particular resource. Looking ahead, central to the Singapore's national energy policy framework are the so-called four 'energy switches': natural gas, solar power, low-carbon alternatives, and integration with the regional power grid.

## 2.1 Natural gas and other fossil fuels, including waste-to-energy

Natural gas constitutes about 95% of Singapore's electricity generation mix with a small amount of oil and coal since 2014 (EMA, 2023b). Currently, natural gas is piped from neighbouring Malaysia and Indonesia and shipped as liquified natural gas (LNG) from distant countries such as Australia, the United States, Qatar, and Angola. Natural gas produces the least amount of carbon emissions per unit of electricity among all fossil fuels and is seen as an important bridge fuel for a more sustainable energy portfolio in the future. The switch from oil to primarily natural gas in electricity generation contributed significantly to mitigating emissions of around 7.6 $MtCO_2e$ in the past decade (Su et al., 2017). However, greenhouse gas (GHG) emissions from gas energy generation attributed in Singapore has increased over the years from 16.26 to 24.65 $MtCO_2e$ between 2012-2021 (Ember, 2022).

In general, power generation units can be deployed through the use of open cycle gas turbines (OCGT) and combined cycle gas turbines (CCGT). To strengthen energy security, EMA is building two OCGT generation units, which are less efficient but has faster startup time compared to CCGTs to respond to gas supply disruptions. Producing 340 MW of electricity each, these units run on natural gas as the primary fuel and diesel as a backup similar to existing generation units (Hong, 2023a). Moreover, industry sources have also suggested that Singapore should consider setting up a strategic reserve facility for diesel as an important alternative fuel for power generation even if it is not cost-effective to mitigate global energy supply risks (Pachymuthu, 2022). Singapore is set to shift toward LNG to meet the bulk of its gas demand in the coming years as piped natural gas supply contracts are discontinued and LNG import capacity is expanded.

Enhanced energy efficiency is one way to reduce emissions from electricity generation using OCGTs and CCGTs, which have an economic lifespan of around 25 years. Singapore's electricity grid emission factor (average operating margin) was 0.417 $tCO_2e$/MWh in 2022 (EMA, 2023b). EMA plans to introduce emission standards for new and repowered fossil fuel-fired generation units of 0.355 $tCO_2e$/MWh based on 75% Plant Load Factor (PLF) and advanced CCGTs[2] for baseload generation units. Advanced CCGTs are expected to be about 10% more efficient than existing CCGTs deployed for electricity generation (Tan, 2023b). For OCGTs, the emissions allowance limit for OCGTs will be equivalent to a Tier 1 advanced CCGT but running at a lower PLF of 50% (EMA, 2023a). Even though coal constitutes just 1% of Singapore's energy mix, Singapore has pledged to phase out the use of unabated coal in its electricity mix by 2050 under the Powering Past Coal Alliance (PPCA)[3].

Singapore has traditionally relied on incineration to achieve the dual objectives of reducing up to 90% of waste volume and converting the heat energy produced as a by-product of the incineration process into electricity. Since 1986, there have been six waste-to-energy (WTE) incineration plants to treat municipal solid waste (MSW) which cover about 2% of Singapore's total electricity needs[4]. Singapore's sixth WTE plant (TuasOne) can generate 120 MW of electricity daily and is designed for higher heat recovery from waste incineration and higher electrical power generation efficiency[5].

The upcoming Tuas Nexus Integrated Waste Management Facility (IWMF) allows co-sharing of resources between a water reclamation plant and a waste management facility. With a total generation capacity of 270 MW[6], it is expected to be completed by 2027 and can produce 1.98 TWh of energy annually. Only 10% of electricity is retained to operate the two facilities and the rest can be exported to the grid (Boh, 2016). Renewable biogas produced from the process of anaerobic digestion is subsequently converted to electricity. This increase in energy self-sufficiency is expected to result in savings of more than 0.2 $MtCO_2e$ annually (Chong, 2021).

## 2.2 Solar

Singapore has excellent solar irradiance. According to SolarGy Pte Ltd, a solar energy solutions company, the annual irradiation recorded in Singapore is between 1580 to 1620 $kWh/m^2$ which makes solar PV the most promising renewable energy option for Singapore. The Solar Energy Research Institute of Singapore (SERIS) estimated that Singapore has the technical potential to deploy up to 8.6 GWp by 2050, which can meet 10% of Singapore's projected energy demand. However, the potential is hindered by limited land availability for large-scale deployment of solar panels and competing uses. Due to solutions such as the deployment of rooftop and floating solar PV facilities over water bodies, installed capacity and the number of grid-connected installations have risen exponentially over the decade[7].

To manage the variability and intermittency of solar energy, Singapore has deployed its first utility-scale energy storage system in 2020 with a capacity of 2.4 MWh and participated in the wholesale electricity market. Singapore has surpassed its 2025 energy storage deployment target three years earlier, with its official opening of its biggest battery energy storage system (BESS) of 200 MW (285 MWh) at the end of 2022. Future AI developments in grid operations to forecast short-term electricity supply and demand may also be useful in mitigating intermittency challenges (EMA, 2022a).

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[2] Best-in-class technologies available in the market expected to be about 10% more efficient than the ones in Singapore's system today.
[3] https://www.nccs.gov.sg/media/press-release/sg-phase-out-unabated-coal
[4] https://www.mse.gov.sg/policies/clean-land
[5] https://www.nea.gov.sg/media/news/news/index/tuasone---the-latest-and-most-land-efficient-waste-to-energy-plant-in-singapore#:~:text=National%20Environment%20Agency-,TuasOne%20%2D%20The%20Latest%20And%20Most%20Land%20Efficient%20Waste,To%2DEnergy%20Plant%20In%20Singapore&text=Singapore's%20sixth%20waste%2Dto%2Denergy,power%20about%20240%2C000%20HDB%20flats.
[6] https://www.power-technology.com/data-insights/power-plant-profile-singapore-new-integrated-waste-management-facility-singapore/
[7] Installed capacity of 670 MWp and 5455 grid-connected installations in the residential and non-residential sectors as of 2022 Q1.

The Housing Development Board (HDB) announced a solar power generation of 540 MWp by 2030 across its public estates which could potentially generate 648 GWh of clean energy per year[8]. The largest home-grown solar power producer Sunseap analysed that its total solar energy generated has helped corporate and retail customers to offset emissions of over 58,000 $tCO_2e$ (Wong, 2020). Singapore aims to increase solar energy deployment from 515.9 MW in 2022 Q1 to at least 2 GWp and meet around 3% of projected total electricity demand in 2030. Research is also being done to produce low-cost solar cells that have an efficiency of at least 30%, up from 25% for typical cells (Tan, 2023a).

## 2.3 Low-carbon alternatives

Here we discuss the potentially more feasible low-carbon alternatives for Singapore in the near and far future based on recent developments.

### a) Hydrogen

Singapore has identified hydrogen as a major decarbonisation pathway and aims to supply up to 50% of its power needs with hydrogen by 2050 (Lee, 2022). Hydrogen power generation technology can potentially achieve a lower installation cost by maximising the use of existing facilities and converting them for hydrogen power generation. This effectively replaces natural gas as the fuel for OCGT and CCGT generation units.

In Singapore, new and repowered OCGT and CCGT generation units are required by EMA to be hydrogen-compatible, meaning both gaseous hydrogen and low-carbon hydrogen derivatives that may be used directly as a fuel. OCGT and CCGT generation units that can accommodate hydrogen blend which consists of 30% volume hydrogen with natural gas are already commercially available in the market today. Over time, as the technology matures and is more cost-effective, EMA may raise the required capabilities for hydrogen-compatibility (EMA, 2023a). Singapore is expected to get its first hydrogen-ready power plant, known as the Keppel Sakra Cogen Plant, by the first half of 2026, which is slated to produce up to 600 MW of electricity. This can lead to a reduction of 0.22 $MtCO_2e$ of emissions annually (Ang, 2022b).

Low-carbon ammonia, another hydrogen derivative, is close to commercial readiness for power generation. Following a proposed minimum power generation capacity of 50 MW[9] by 2027 initially, the Maritime & Port Authority of Singapore (MPA) is exploring collaboration opportunities with EMA for an ammonia power generation project with a generation capacity between 55 MW and 65 MW from imported low-carbon or zero-carbon ammonia via direct combustion in OCGTs and CCGTs, bypassing the need for conversion to hydrogen and thus avoiding the energy losses associated with conversion processes (Lim, 2023). One issue with ammonia fuel is that, even though it does not emit $CO_2$ when combusted, it emits nitrogen oxide, which has significantly more greenhouse warming potential than $CO_2$.

Moving forward, Singapore would also need to monitor its hydrogen supply chain to ensure that green hydrogen produced by renewable electricity is prioritised rather than blue hydrogen produced via a steam methane/natural gas reforming process. It is a

[8] https://www.aseanbriefing.com/news/hdb-green-towns-supporting-singapores-sustainable-development-goals/#:~:text=HDB%20announced%20a%20solar%20power,%2C%20four%2Droom%20HDB%20apartments.
[9] https://ammoniaenergy.org/articles/exploring-ammonia-retrofits-at-the-sakra-power-plant-singapore/

promising sign that Singapore's sole piped town gas producer and the nation's gas utility provider, City Energy is conducting a feasibility study with Gentari, Petronas' renewables unit, on a proposed pipeline to export hydrogen from Malaysia to the city state, with a view that it becomes operational by 2027, in time to supply the fuel mix for Singapore's new hydrogen-ready power plant (Daiss, 2023).

## b) Geothermal

Singapore has no known shallow heat source but has three confirmed hot springs situated at or near the coasts and estimated anomalous heat flow. Oliver (2010) investigated the feasibility of constructing a 50 MW commercial geothermal power generation station. This would involve the drilling of "3 km deep directional wells in hot sedimentary aquifers or in hot, wet and fractured granite and the generation of electricity from 150°C hot water through binary cycle turbines with wastewater being recycled down injection wells".

Conventional hydrothermal systems may be unsuitable for Singapore due to the lack of sufficient hot water and steam resources at shallower depths. However, EMA is currently conducting a feasibility study of using advanced geothermal systems (AGS) to extract heat from hot and dry rock from deep underground using fracking or closed-loop system methods with minimal negative environmental and safety externalities.

Nanyang Technological University (NTU) has been collaborating with TUM Create and Surbana Jurong Group since October 2021 to study the rocks' elemental concentration and the temperature of the granites from deep boreholes in the northern and eastern regions like the Sembawang hot spring park and Pulau Tekong that have higher surface temperatures and are deemed to have geothermal potential[10]. Based on current heat extraction and utilisation technologies, it was assessed that drilling a 4km to 5km depth is considered somewhat viable, where the geothermal site could start having a temperature of 200 degrees Celsius or more (Ng, 2023b).

In assessing the feasibility of harnessing geothermal energy, EMA has several key considerations. The first is about technical feasibility i.e., is it technically feasible to map the underground within the territorial waters surrounding Singapore and if so, are there any specific regions of territorial space that the project should focus on? The second consideration is about trade-offs with respect to the extent of coverage i.e., should the project cover the whole of Singapore (including territorial waters and offshore islands) or only mainland Singapore, including the cost and time of conducting the appropriate geological surveys? The third consideration is about the need for invasive methods associated with the drilling of boreholes and lastly, besides geothermal potential, whether it is appropriate to also assess $CO_2$ storage potential and potential for deploying underground power plant infrastructure in the process (EMA, 2022c).

[10] https://www.ntu.edu.sg/erian/news-events/news/detail/singapore-digs-deep-to-unleash-geothermal-energy-potential

## c) Nuclear

Given the geographical and geological limitations of scaling up renewables, nuclear power could be an attractive option to achieving net zero emissions in the power sector. A pre-feasibility study of the deployment of nuclear energy in Singapore conducted in 2012 concluded that nuclear energy technologies available then were not deemed sufficiently risk-proof due to the small size and density of the city-state (MTI, 2012).

However, modern advances in nuclear technology such as small modular reactors (SMR), floating nuclear power plants (FNPP) and nuclear fusion development have since alleviated some of the safety, spatial and environmental concerns associated with conventional large reactor technologies. Despite their small size, SMRs can generate nearly 300 MW of electricity, about one-third of the generation capacity of conventional nuclear reactors (Igini, 2022). An FNPP can generate between 200 megawatts electrical (MWe) to 800Mwe which can easily power about 350,000 to 1.4 million HDB flats in Singapore for a year. The 2050 Energy Committee Report has assessed that nuclear energy could supply about 10% of Singapore's needs by 2050 (Ang, 2022a).

Although nuclear SMRs and FNPPs remain politically challenging to deploy in and around Singapore even with the additional safety mechanisms, almost 60% of 620 young people in Singapore surveyed in mid-2021 say Singapore should consider adopting nuclear energy as part of its energy mix and over 90% think insufficient attention has been given to nuclear energy by the government, schools and the media[11].

With other ASEAN countries such as Indonesia, the Philippines and Vietnam also announcing national nuclear energy ambitions or are carrying out feasibility studies, nuclear SMRs and FNPPs may also be instrumental to sustainable financing and transforming Singapore's competitive advantage from a fossil fuel importer/re-exporter to being a green-energy exporter and regional nuclear capacity building hub in the long-term.

A new multimillion-dollar research building at the National University of Singapore (NUS) will house about 100 researchers working on nuclear-related technology such as SMRs and dispersion of radioactive materials if there is an accident (Tan, 2024). In 2023, NTU announced a new research centre for nuclear fusion with France's Alternative Energies and Atomic Energy Commission, known as the Singapore Alliance with France for Fusion Energy[12].

## d) Carbon Capture

Carbon capture utilisation and storage (CCS) is currently still in its infancy phases for Singapore due to the lack of appropriate geological sites such as gas and oil fields for the permanent storage of $CO_2$ underground, which entails additional transport costs to suitable sites. In addition, a substantial amount of capital investment is needed for the extraction and conversion of carbon into fuel, as well as for plant maintenance (NCCS, 2020). Nevertheless, Singapore is aiming to realise at least 2 $MtCO_2e$ of carbon capture potential by 2030 as part of a broader effort to make its energy and chemicals

[11] https://www.nuclearbusiness-platform.com/media/insights/insights/is-nuclear-power-singapores-best-bet-for-energy-independence
[12] https://www.ntu.edu.sg/erian/news-events/news/detail/ntu-deepens-research-and-academic-ties-with-france

sector more sustainable and achieve more than 6 million tonnes of carbon abatement per annum by 2050[13].

A national feasibility study on carbon capture at WTE plants is also currently being conducted (Hong, 2023b). The feasibility and development of a $CO_2$ liquefaction and storage facility is also explored, where existing cold energy from the production of liquefied natural gas (LNG) is utilised to liquefy $CO_2$, thereby directly capturing $CO_2$ which may otherwise be emitted into the atmosphere (Jaganathan, 2021).

## 2.4 Regional power grid

Singapore has a target of importing 4GW of low-carbon electricity by 2035, which will make up about 30% of Singapore's projected energy supply in the same year. According to ASEAN Centre for Energy (AEC) (2022), Singapore is projected to be the second-largest electricity importer in the region, sourcing around 11% on average of its electricity demand from neighbouring countries from 2025-2050.

Under the Lao PDR-Thailand-Malaysia-Singapore Power Integration Project (LTMS-PIP), Singapore is importing 100 MW of renewable hydropower from Laos through Thailand and Malaysia using existing interconnectors from June 2022 as a two-year pilot phase, with full-scale commercial operation to follow. EMA appointed YTL PowerSeraya as the importer for a 100 MW trial from Peninsular Malaysia, whereby electricity will be supplied via the existing interconnector between Singapore and Peninsular Malaysia over a period of two years starting in 2024.

Singapore also intends to explore the development of offshore wind farms in Vietnam to export electricity to Singapore and has signed an agreement to import 1.2 GW of wind-powered electricity from Vietnam (Yong, 2023; Tan, 2023d). Singapore-based Vena Energy is aiming for a 2026 construction start for its 2 GW solar and battery project in Indonesia's Riau Islands. This project plans to export up to 2.5 TWh of electricity annually to Singapore when it is completed in phases by 2032 (Fogarty, 2023). 2 GW of solar PV-generated electricity is slated to be imported from five other firms in Indonesia by end-2027 (Baharudin, 2023).

Singapore is also negotiating with Sarawak to import up to 1GW of hydropower-generated electricity via new submarine cable technology by 2032 (Saieed, 2023). Conditional approval has also been approved to import 1 GW of renewable energy annually from Cambodia after 2030 (Tan, 2023c). The Conditional Approvals that EMA has granted as of February 2024 are 1 GW from Cambodia, 2 GW from Indonesia and 1.2 GW from Vietnam[14].

In 2022, the Sun Cable Project was conceptualised to use a 4,200km-long power cable to export 1.75 GW of electricity from Australia to Singapore. Although it was expected to be ready by 2027, it is no longer deemed to be commercially viable at the time of writing (Ng, 2023a).

[13] https://www.twobirds.com/en/insights/2024/singapore/carbon-capture-utilisation-and-storage-ccus-a-singapore-perspective#:~:text=In%202021%2C%20the%20Singapore%20government,abatement%20per%20annum%20by%202050.
[14] https://www.ema.gov.sg/our-energy-story/energy-supply/regional-power-grids#:~:text=Large%2Dscale%20Electricity%20Imports,-In%20July%202022&text=The%20Conditional%20Approvals%20that%20EMA,low%2Dcarbon%20electricity%20by%202035.

# 3. SINGAPORE'S DOMESTIC ENERGY DEMAND TRENDS AND POLICY TARGETS

We now shift our attention to the demand aspect, with a particular focus on three important sectors: transport; industry; residential and commercial.

## 3.1 Transport

For transportation, one important aspect of the green transition lies in electric vehicles. Singapore currently has more than 6,500 registered electric cars, and close to 10,000 EVs including other vehicle classes. Hybrid and electric cars and taxis constituted about 12% of the total car and taxi population in 2022, which is a significant increase from their less than 1% share in 2012 (LTA, 2022). It is reported that with the deployment of 60 electric buses in 2020, the $CO_2$ tailpipe emissions from buses will decrease by approximately 7,840 tons annually[15].

The Land Transport Authority (LTA) has laid out several policies to promote mass electrification of private and public transport. LTA aims to install 12,000 EV charging points by 2025 and 60,000 by 2030. From 2025, there will be no new diesel car and taxi registrations and from 2030, all newly registered cars and taxis to be of cleaner energy models. Half of the bus fleet will be electrified by 2030 with the goal of achieving a 100% cleaner energy bus fleet by 2040[16]. As per the Vehicle Quota System (VQS), the car and motorcycle population growth rate will be maintained at 0% per annum while goods vehicles and buses will maintain a 0.25% population growth until 31 Jan 2025 (Ong, 2021). The ultimate goal would be to phase out all internal combustion engine (ICE) vehicles by 2040.

Tightened pollutant thresholds for the purchase of cleaner car models will be introduced from 2024 to 2025 under the enhanced Vehicular Emissions Scheme (VES). The Ministry of Transport also aims to achieve 75% mass public transport (i.e., rail and bus) modal share by 2030 and double the length of the railway network. Tightened emission limits of 4.5% carbon monoxide by volume and 7,800 ppm hydrocarbons (for 2-stroke engine) or 2,000 ppm HC (for 4-stroke engine) will also be introduced for local motorcycles registered before 1 July 2023[17].

By 2030, the Maritime Port Authority of Singapore (MPA) aims to reduce absolute emissions from the domestic harbour craft fleet by 15% from 2021 levels, through the adoption of lower-carbon energy solutions such as blended biofuel, LNG, diesel-electric

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[15] https://www.lta.gov.sg/content/ltagov/en/industry_innovations/technologies/electric_vehicles/our_ev_vision.html
[16] https://www.lta.gov.sg/content/ltagov/en/industry_innovations/technologies/electric_vehicles/our_ev_vision.html#:~:text=We%20have%20started%20by%20deploying,emissions%20of%201%2C700%20passenger%20cars.
[17] https://www.nea.gov.sg/media/news/news/index/in-use-emission-standards-for-older-motorcycles-and-noise-standards-for-all-vehicles-will-be-tightened-in-april-2023#:~:text=Tightened%20In%2Duse%20Emission%20Standards,-2%20On%206&text=Hence%20from%206%20April%202023,for%204%2Dstroke%20engine).

hybrid propulsion, and full electric propulsion. By 2050, MPA aims for the harbour craft fleet to halve 2030-level emissions by transitioning to full-electric propulsion and net zero fuels.

## 3.2 Industry and services

Sectors in Singapore can be classified into 2 broad categories, mainly goods-producing industries (manufacturing, construction, utilities) and service- producing industries (food and beverage, real estate, wholesale trade, information and communication technologies, retail trade, professional services, administrative and support, transportation and storage, finance and insurance, accommodation). Within the manufacturing sector, key industry clusters include transport and precision engineering, electronics, biomedical and chemicals.

Carbon taxes are expected to influence the decisions of firms. The carbon tax, priced at S$5/t$CO_2$e, was introduced in 2019 through the Carbon Pricing Act (CPA), which is applied to all industrial facilities (manufacturing and manufacturing related services; supply of electricity, gas, steam, compressed air and chilled water for air-conditioning; and water supply and sewage and waste management) with an annual direct GHG emissions of 25,000 t$CO_2$e. It is slated to increase to S$25/t$CO_2$e in 2024 and 2025, S$45/t$CO_2$e in 2026 and 2027, with the goal of reaching S$50 to S$80/t$CO_2$e by 2030[18]. New industrial facilities will have to meet minimum energy efficiency standards (MEES) of 0.67 kW/RT in their water-cooled chilled water systems from 2020 Q4 which will reduce their energy consumption by at least 245 GWh annually[19].

In Southeast Asia, Singapore has the largest data-centre market on a city basis, with around 917 MW of capacity in operation, and 209 MW either planned or under construction[20]. Singapore data centre market size is estimated at 0.88 GW in 2024 and possibly exceeding 1 GW, and is expected to reach 1.02 GW by 2029, growing at a CAGR of 2.89% from 2024-2029[21].

## 3.3 Residential and commercial

Finally, we turn to the residential and commercial sectors. To manage the use of household appliances, the National Environment Agency (NEA) tightened the Minimum Energy Performance Standards (MEPS) for air conditioners, refrigerators and clothes dryers based on coefficient of performance for air-conditioners and energy consumption for refrigerators and clothes dryers[22] in 2021.

For housing, a key aspect of the HDB Green Towns Programme[23] aims to reduce energy consumption in HDB towns by 15% (from 2020's levels) by 2030. This is done through the installation of more solar panels, smart LED lighting, Light Emitting Surfaces (LES) Block

[18] https://www.nccs.gov.sg/singapores-climate-action/mitigation-efforts/carbontax/
[19] https://www.reach.gov.sg/Participate/Public-Consultation/National-Environment-Agency/Resource-Conservation-Department/Public-Consultation-on-the-Introduction-of-MEES-for-Water-cooled-Chilled-Water-Systems#:~:text=Minimum%20Energy%20Efficiency%20Standards%20(MEES),-9%20Unlike%20the&text=For%20chilled%20water%20temperature%20of,of%20the%20chilled%20water%20temperature.
[20] https://www.businesstimes.com.sg/startups-tech/startups/singapores-data-centre-market-surpass-1gw-milestone-challenges-ahead-cushman
[21] https://www.mordorintelligence.com/industry-reports/singapore-data-center-market
[22] https://www.nea.gov.sg/media/news/news/index/nea-to-enhance-minimum-energy-performance-standards-(meps)-for-refrigerators-clothes-dryers-and-air-conditioners
[23] https://www.hdb.gov.sg/about-us/our-role/smart-and-sustainable-living/Green-Towns-Progamme

Signages and retrofitting selected lifts with the Elevator Energy Regeneration System (EERS)[24].

The deployment of advanced electricity meters to facilitate real-time tracking and managing of energy usage in Singapore households is also gaining more traction. 650,000 smart electricity meters have been deployed islandwide and all 1.4 million residential households in Singapore are estimated to be equipped with smart meters over the next few years (NCCS, 2020). A smart meter trial in 2009 known as the Intelligent Energy System (IES) found an average reduction of overall electricity consumption of 2.4% and a 3.9% reduction in peak usage. This is a consequence of households being able to monitor household power consumption in real time with the implementation of time-of-use pricing[25].

Under the Building Construction Authority (BCA) Green Mark 2021, new and existing buildings will need to meet higher minimum energy efficiency levels and score sufficient points in the sustainability sections to be certified green. It targets greening 80% of Singapore's buildings by Gross Floor Area by 2030, 80% of new developments to be Super Low Energy buildings from 2030, and 80% improvement in energy efficiency to best-in-class green buildings by 2030[26]. Singapore has also made it easier for new buildings to get certified as green if new installations use electricity instead of gas connections for cooking (Hicks, 2023).

[24] The EERS converts energy generated from lift motions and braking operations into electrical energy to power other services within the lift such as lights and ventilation fans.
[25] https://www.siew.gov.sg/articles/detail/2010/08/01/singapore-smart-grid-city
[26] https://www1.bca.gov.sg/docs/default-source/docs-corp-news-and-publications/media-releases/bca-green-mark-2021-certification-scheme.pdf

# 4. REVIEW OF PAST CLIMATE MODELLING WORK FOR SINGAPORE

To benchmark our work, we now turn to past climate modelling work in the context of Singapore.

Based on 3 scenarios [Baseline (BAS)[27], Business As Usual (BAU)[28] and Alternative Policy Scenarios (APS)[29]], Doshi and D'Souza (2013) found that Singapore can reduce its final energy consumption and energy intensity by around 12%–14% and $CO_2$ emissions by 19-22% in the BAU and APS scenarios from the BAS level by 2050. In the power sector by 2050, this assumes that existing OCGT generators are replaced by CCGT generators. Moreover, all new gas fired power plants commissioned from 2007 to 2030 are assumed to employ CCGT generators with higher overall efficiency of both gas-fired and oil-fired power plants. There is also higher solar PV share.

In the transport sector, the compound annual growth rates of diesel and gasoline fuel as well as electricity consumption of vehicles are modelled based on vehicle growth. In the residential and commercial sector, the electricity saving potential of using energy efficient appliances was estimated based on the Energy Labelling Scheme and reduction in electricity consumption of buildings under the BCA Green Mark Scheme. In the industrial sector, they estimated the energy savings potential of the Energy Efficiency National Partnership (EENP) programme, which is an industry-focused voluntary partnership programme for companies that wish to be more energy efficient.

Loi (2019)'s assumptions in the power sector are similar to those of Doshi and D'Souza (2013). Based on a BAU[30] and 4 APS[31], Loi (2019) found that carbon abatement potential can reach 50 $MtCO_2e$ by 2020 under the most ambitious scenario. The demand of naphtha in the industrial sector is also accounted for, which is used as an intermediary fuel to produce petrochemicals for re-exporting purposes.

Based on 2 scenarios (BAU and Carbon-Neutral), Asia Pacific Energy Research Centre (APERC) (2022) incorporated assumptions of gas-fired CCS technologies, LTMS-PIP and Sun Cable project viability, greater increase of solar deployment, phasing out of coal, as well as SLNG import and LNG re-exports in the power sector. They also modelled energy and material efficiency measures, cleaner fuel substitution in the industrial and commercial sectors, as well as electrification and modal switching in the transport sector. They found that the BAU scenario is more than sufficient for Singapore to achieve its previous NDC target of 65 $MtCO_2e$ by 2030 but will require additional offsets or sequestration to reduce its remaining emissions of 16 $MtCO_2e$ in 2050 in the Carbon-Neutral scenario.

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[27] Assumes that only the policies in place by the end of 2007 are implemented.

[28] Projects energy use and $CO_2$ emissions taking into consideration energy policies implemented up until end-2010.

[29] Projects energy use and $CO_2$ emissions taking into consideration more ambitious energy efficiency and conservation policies compared to BAU.

[30] Includes policies of improved generation efficiency of combined-cycle and single-cycle turbine/thermal plants, solar generation capacity increase, vehicle growth reductions, railway efficiency improvements, slower electricity demand growth in the residential and commercial sectors, slower demand growth for natural gas, electricity and oil products in the industry/petrochemicals sector, linear growth in the production of ethylene, and constant naphtha demand.

[31] Greater potential for efficiency of combined-cycle and single-cycle turbine/thermal plants (APS2), higher share of solar deployment (APS3), further reduction in electricity demand growth in the residential and commercial sectors (APS1) and even slower demand for natural gas, electricity and oil products in the industry/petrochemicals sector (APS1) compared to BAU.

ASEAN Centre for Energy (AEC) (2022) modelled projections of energy demand and supply of the ASEAN region based on 3 scenarios (baseline, national and regional targets) from 2021 to 2050. In the case of Singapore, national targets pertaining to the improvement of industrial energy efficiency, reduction in energy intensity and consumption as well as achievement of 100% cleaner-energy public bus fleet and taxis by 2040 were modelled.

# 5. THE LEAP MODEL

Our model builds on the Low Emissions Analysis Platform (LEAP), a software system designed for assessing climate change mitigation and integrated energy planning. Developed by the Stockholm Environment Institute (SEI), the LEAP framework is a popular tool that is used by many countries in the assessment of GHG emissions.

## 5.1 Key assumptions, energy and emissions-related data in all domestic sectors

In LEAP, we first inputted key assumptions pertaining to country demographics, extent of urbanisation, GDP, vehicle population, distance travelled by vehicle[32], value-added to GDP by sector etc. The base year is set at 2009, the first scenario or projection year[33] in 2023 and the end year in 2050. For GDP in the baseline, we selected SSP2 which represents a "middle of the road" scenario where historical patterns of development are continued throughout the 21st century. Total final energy demand covers energy demands in four end-use sectors—industry, residential, transport and services.

Demand sectors typically rely on the top-down approach i.e., starting with aggregated energy consumption levels to model historical energy demand until the first scenario year, which is when the bottom-up approach takes over in calculating projected energy demand (and its corresponding emissions).

Based on the top-down approach, a historical growth function can create an average growth rate of the average energy intensities and fuel shares based on historical trends from the base year to the last historical year, which is then used as a basis to project future values to the last projection year. The projected growth rate can also be constrained to ensure that it does not unrealistically exceed historical growth rates. In our model, growth rates of over 50% are disallowed. The equation of the growth constrain function is as follows:

$$\text{Growth}(\text{Constrain}(\text{HistoricalGrowth}(\text{ProjectionYear}, \text{LastHistoricalYear}), \text{MaxIntensityGrowth}))$$

An exception was made for the final energy intensity of the services sector, whereby a negative sign was added to the original equation above in the first parenthesis to create an inverse growth constrain function. The reasoning is that applying a direct growth constrain function in the services sector would project a slight downward trend in energy intensity in the later years based on historical trends. However, a steeper increasing trend may be more likely considering the government's intention to grow the services sectors and anchor Singapore as a leading, vibrant hub for businesses, data centres, lifestyle and tourism (MTI, 2024).

Conversely, for the residential and transport sectors, a bottom-up approach i.e., starting with per capita energy consumption levels was used for the projection period. The projections based on the bottom-up approach are mainly driven by policy changes that

[32] Retrieved from https://datamall.lta.gov.sg/content/datamall/en/search_datasets.html
[33] First year in which projections are made and when LEAP starts using process dispatch rules.

affect either the composition of the disaggregated shares in the defined activity levels or the energy efficiencies of the defined technologies.

Calibration factors for fuels used in the transport and residential sectors were derived by setting the first scenario year (2023) to one year earlier[34]. Subsequently, we divided the actual energy demand values by the projected values in that same year for each type of fuel in both sectors where necessary. The purpose of the calibration factors is to smoothen out the transition with regards to the energy consumption of each fuel by the corresponding demand sector from the historical period to the projection period since the methodologies and data used to calculate energy consumption in both periods may vary[35].

Within the residential sector, in the historical period, energy intensity was calculated based on the historical total energy consumption [natural gas, electricity and liquified petroleum gas (LPG)] divided by the number of households. In the projection period, we disaggregate the residential sector into 11 main technologies, mainly: cooking, lighting, refrigeration, air-conditioning, water heating, washing machine, television, entertainment boxes, computers, fans and others. Each type of residential activity is then disaggregated by its corresponding fuel types. The projected energy demand can be calculated as the number of households multiplied by the shares of households using each type of technology for each activity and by the estimated annual energy consumption per household for each type of activity for each fuel type.

Within the transport sector, we disaggregate it into the various modes of transport, mainly: road, rail and domestic shipping. For road transport, in the historical period, energy intensity was calculated based on the historical total energy consumption (diesel, natural gas and gasoline) divided by the total annual mileage of all vehicles. A five-year weighted average of annual mileage was computed for each mode of vehicle (2019-2023). We derived the average daily distance travelled per public bus between 2005-2014 (the latest year that data was available) by dividing the average daily distance travelled by the number of public buses in each corresponding year and multiplying it by 365. The number of private hire buses, school buses and public buses, as well as that of light goods vehicles and heavy goods vehicles, were multiplied by their respective distances travelled and divided by their total respective populations to derive an average of the distance travelled by a bus and freight truck in Singapore.

In the projection period, we further disaggregate road transport by vehicle type, mainly: cars and taxis, buses, motorcycles and goods and other vehicles, and these are further disaggregated into the various types of engine technology (petrol, diesel, CNG, petrol-CNG, electric hybrid[36], fully electric). Each mode of vehicle by fuel type is then further disaggregated into their respective VES bands from A1 to C2 where data is available. Vehicles belonging to A1 band are the "cleanest" on the road such as the more efficient fully electric vehicles while vehicles belonging to the C2 band are the most energy inefficient/emitting. For electric hybrid cars and taxis, we disaggregate them into regular[37] and plug-in[38] hybrid instead. Singapore's railway system is fully electrified.

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[34] Even though fuel consumption patterns in 2022 may be influenced by post-COVID-19 pandemic recovery, the economic relationships in key sectors observed prior to the pandemic may no longer apply to the current market dynamics, which have evolved rapidly over the past five years. By calibrating with the most immediate preceding year, we ensure that the model reflects the immediate past conditions. This approach is likely to yield more accurate short-term forecasts and provide a more relevant basis for modelling future trends than using an average of older data that may not reflect recent significant changes in energy policies and technological advancements etc.

[35] The historical period is usually based on readily available data i.e. top-down or aggregated data and we have no detailed information on how it is computed. The projection period allows us to experiment with our own calculations from a bottom-up approach with various variables where available, as the granularity of the analyses will be higher i.e., by technology type.

[36] Can be petrol-electric or diesel-electric.

[37] Powered by both a petrol-fuelled internal combustion engine and a battery-powered electric motor that can work either independently or simultaneously.

[38] Powered chiefly by an electric motor and will only use its internal-combustion engine as a back-up should the electric motor's battery be depleted.

Energy demand in the road and freight transport subsectors can be calculated as the shares of each vehicle type by type of fuel and by their corresponding VES bands, multiplied by their corresponding fuel economies (energy consumption per vehicle-kilometres travelled) and the annual vehicle mileage. Because this method of calculating emissions is independent of energy consumption, we also include calibration factors for road transport emission factors to ensure scale equivalence between emissions in the historical and projection periods for road transport.

Within the industrial sector, we focus on goods-producing industries, mainly construction, manufacturing, utilities and other goods industries. Currently, we cannot further disaggregate the various types of energy consumption by each subsector within the manufacturing and services sector due to data unavailability. In both the historical and projection periods, energy intensity was calculated as the total energy consumption of each subsector divided by the value-added of industry/services to GDP.

For the transformation module, we focus on electric generation. We derived the yearly electricity peak load shape curve for Singapore using hourly system demand data[39] from EMA based on a total of 2016 time intervals[40] (12 months/7 days of the week/24 hours). The load shape is specified by entering the percentage fraction of annual energy demand that occurs in each slice of the year. Given data availability at the time of writing, hourly solar irradiation data for the year 2019[41] from Renewables.ninja[42] was used to estimate the maximum fraction of hours that each electricity generation is available in each time slice and to derive the solar availability shape (Pfenninger and Staffell, 2016).

We inputted historical production, exogenous capacity and process efficiency values for natural gas OCGTs, CCGTs and oil-fired power plants which we assumed use steam turbines[43], as well as for coal and biomass cogeneration power plants, solar PV and WTE plants. Data was retrieved from the 2023 edition of the Singapore Energy Statistics (SES). Generally, the historical annual fuel mix proportions as reported in SES were multiplied by the total electricity production in the corresponding years[44] to estimate the historical production of the various processes.

To disaggregate the proportions of natural gas used to generate electricity into OCGT and CCGT, the ratios of the generation capacities of OCGT to CCGT were used in the corresponding years. Because it was reported that Singapore's WTE provided about 2.5% and 2.3% of the total electricity generated in 2018 and 2020 respectively, we assumed that solar PV provided about 0.3% and 0.5% of the total electricity generated in the same years respectively based on the fuel share of the "Others" category (NEA, 2018; 2022). To estimate the annual amount of electricity generated by WTE and solar PV, as WTE generation capacity is constant from 2009-2021 but solar PV is not, the annual solar PV fuel mix shares during that period can be derived by scaling up/down solar PV's share of electricity generated in 2018 and 2020 and taking the average of the two, according to how much they differ from the solar PV generation capacity in each of the other years, with

[39] https://www.ema.gov.sg/resources/statistics/half-hourly-system-demand-data
[40] Even though we could technically go up to 8760 time intervals based on available data and LEAP's capabilities, the resolution needs to be significantly reduced for the simulation to run at an acceptable speed.
[41] Although 2019 might be an outlier year in terms of Singapore having a record-high solar intensity, the total mean capacity factor for the year 2019 only differs by 1.2% from the average over the past 10 years (2014-2023). Moreover, if we were to examine it by month, the solar irradiation received is only higher in 5 months (April, June, July, August and October) within a year compared to each of the past 10 years, and the difference from the 10-year average in any given month ranges from only 0.7-2%. Alternatively, we can also look at it as a 'best-case' scenario for solar PV generation in Singapore, providing valuable insights into its maximum power generation potential. Moreover, it is plausible that Singapore could experience years hotter than 2019 in the future, potentially even breaking previous heat and solar intensity records due to the trends in global warming.
[42] https://www.renewables.ninja/
[43] The Tuas Steam Turbine Power Plant and Pulau Seraya Steam Turbine Power Plant are oil-fired plants, according to Power-technology.com.
[44] From CEIC Data: Electricity Generation: Annual: Singapore, series ID: 409116327.

the remainder proportion in the "Others" fuel mix being WTE. For 2008 and 2022 when both WTE and solar PV generation capacities were different from that in 2018/2020, the difference between the WTE generation capacity in 2018/2020 and the WTE capacity in that particular year were also taken into account during the adjustment. Because we have no information on the composition of oil products combusted in oil-fired power plants, we took the proportional difference of emissions generated from diesel and fuel oil in energy industries as reported in the Singapore's National Communication and Biennial Update Report of various years and adjusting for their differences in the IPCC Tier 1 default $CO_2$ emission factor to approximate the historical fuel shares.

The generation capacity of Singapore's only coal-fired power plant known as the Tembusu Multi-Utilities Complex (TMUC) has a generation capacity of 133.5 MW[45] and uses a mix of coal and biomass to produce electricity, generating an average of 588.9 GWh annually[46]. We assume a co-firing feedstock fuel ratio of 80% coal bituminous and 20% biomass in 2014 when the plant first opened, to 70% coal bituminous and 30% biomass in 2023[47].

EMA estimated that existing local generation has been observed to achieve 90% availability, which is defined as the amount of time that a generation process is able to provide electricity over a year, after accounting for planned and unplanned outages (EMA, 2022d). We assume that this applies to all generation processes, including electricity imports and the other cleaner and more renewable energy technologies without existing data on availability in each time slice.

We added two new fuels to the LEAP fuel database and their production plant modules. These fuels are hydrogen blend which is synthesised from 70% natural gas and 30% hydrogen and low-carbon ammonia which is assumed to be synthesised from 25% natural gas indirectly (by converting to blue hydrogen in the first stage) and 75% green hydrogen directly[48] as well as their associated chemical properties. Thereafter we added hydrogen and low-carbon ammonia power plants under the electricity generation module. We assume an initial co-firing feedstock fuel ratio of 30% hydrogen blend and 70% natural gas in 2026 when the Keppel Sakra Cogen Plant first opened. Process efficiencies of fuel combustion for hydrogen and low-carbon ammonia power generators are set at 65%[49] and 40% respectively (Sánchez et al., 2021).

Considering transmission losses for high voltage direct current (HVDC) cables of 12.9%, we estimate the "process efficiency" of electricity imports to be about 87% (DeSantis et al., 2021). WTE plants' historical emissions data[50] were sourced from Singapore's National Communication and Biennial Update Report of various years and then divided by the estimated historical electricity production in those years to obtain the environmental loading factor in terms of per unit of energy produced. According to the IPCC Guidelines, $CO_2$ emissions from waste incineration are estimated from the portion of waste that is fossil fuel based, thus biogenic $CO_2$ emissions are not considered along with methane and nitrous oxide emissions as they are dependent on waste volume (NEA, 2022). Because it

[45] It is likely that the component of the TMUC's generation capacity that contributed to the national grid is included under the Tuas Power "CCGT/Co-Gen-Tri-Gen" generation capacity as reported in the SES. However, although there was indeed an increase in capacity of 32.5 MW in the first half of 2014 as per Phase 2a of the TMUC project, which aligns with the differences in capacity between 2013-2014 under the "CCGT/Co-Gen/Tri-gen" category reported in the SES, Phase 2b's additional 32.5 MW of generation capacity was not included by 2017, when all construction activities should have been completed by then. Given the lack of explicit reporting, we decided to report the TMUC's generation capacity separately, with the caveat that this could result in a slight overlap and overestimation of the natural gas CCGT generation capacity in this model.
[46] https://www.mti.gov.sg/Newsroom/Parliamentary-Replies/2022/01/Written-reply-to-PQ-on-electricity-generation-of-coal
[47] https://sbr.com.sg/energy-offshore/exclusive/tuas-power-diversifies-business-singapores-energy-transition#:~:text=We%20have%20a%20plant%20which,in%20the%20years%20to%20come.
[48] While low-carbon ammonia is to be primarily imported to Singapore, we assume the possibility that it can be domestically synthesised by partial steam reforming of natural gas. Auxiliary fuel value according to https://www.iipinetwork.org/wp-content/letd/content/steam-reforming.html
[49] https://www.twi-global.com/technical-knowledge/faqs/what-are-the-pros-and-cons-of-hydrogen-fuel-cells
[50] Includes emissions from the incineration of solid waste and sludge.

is not possible to model imported renewable electricity directly for comparison purposes with the other power generation technologies, it is also included as a process module under electric generation.

Auxiliary fuel[51] electricity values for power generation technologies are based on the International Energy Agency (IEA) World Energy Balances 2020 values for Singapore and assumed to be allocated equally to all processes (including the new ones that are not deployed yet). The planning reserve margin[52] is set at 27% as per the required reserve margin set by Singapore's Ministry for Trade and Industry. IPCC Tier 1 default emission factors were used to approximate the average environmental loading factors in grams per unit of energy consumed based on the emissions generated from the combustion of feedstock and auxiliary fuels.

For goods producing industries and services, we inputted historical industrial-related energy consumption values for natural gas, petroleum products, coal and peat, and electricity from the SES. Due to a lack of information in the SES on the type of petroleum products consumed, we inferred the proportions of fuel oil, refinery gas, diesel, LPG and petroleum coke in goods producing industries based on energy consumption data on chemical and petrochemical industries[53] and other industries from IEA World Energy Balances (2020) for the same years and multiplied them by the aggregated data from SES. Likewise, we infer that the services sector use primarily LPG based on IEA World Energy Balances (2020).

For the residential sector, we updated historical energy consumption household values for natural gas, oil and electricity using data from SES. We assumed that oil consumption in the residential sector is referring to LPG consumption according to the United Nations databank[54]. The percentages of households who use various technologies for the 11 main activities were also updated or inferred based on the Department of Statistics Report on the Household Expenditure Survey 2017/18[55]. The amount of electricity consumed by each type of household activity was first derived from dividing the total annual household electricity consumption by dwelling type in 2017 as reported in the SES, by the number of households in 2017. This was then multiplied by the respective household appliance energy consumption proportions based on Singapore's household energy consumption profile in 2017 from the Household Energy Consumption Study 2017[56] and weighted according to each of their corresponding actual or assumed penetration rates. We assume that town gas is applicable only to cooking (LPG) and water heating (natural gas), and that 62% of households use town gas[57], while the rest use electric-powered cookers and water heaters. We then divided the total household annual town gas consumption by dwelling type as reported in the SES by the number of households that presumably use town gas and assumed that it can be allocated based on the relative proportions of kitchen appliances to water heaters according to Singapore's household energy consumption profile in 2017. The other activities are assumed to be fully electrified.

[51] Energy use per unit of energy consumed or produced.
[52] Reserve margin refers to the percentage of generation capacity that needs to be kept on top of what the peak demand is. Also see: https://www.mti.gov.sg/Newsroom/Parliamentary-Replies/2022/11/Written-reply-to-PQ-on-Power-Generation-Capacity#:~:text=Over%20the%20last%205%20years,demand%20of%20around%207.8%20GW
[53] Because industrial-related sectors do not consume crude oil according to SES, we assume that the oil refining sector (which consumes crude oil) is not included here and is instead modelled under the transformation sector, using historical production, exogenous capacity and process efficiency values from IEA World Energy Balances (2020).
[54] http://data.un.org/Data.aspx?d=EDATA&f=cmID%3ALP%3BtrID%3A1231
[55] https://www.singstat.gov.sg/publications/households/household-expenditure-survey
[56] https://www.nea.gov.sg/our-services/climate-change-energy-efficiency/energy-efficiency/household-sector/household-electricity-consumption-profile
[57] Note that this may not be entirely accurate as town gas also consists of other types of gases besides LPG such as natural gas. However, because the composition of town gas is currently unknown, we assume that it is primarily LPG that is used for cooking as LPG is a superior cooking fuel.

For the transport sector, we inputted historical transport-related energy consumption values for natural gas, oil and electricity using data from SES. Similar to goods producing industries, due to a lack of information in the SES on the type of oil consumed, we inferred the proportions of gasoline and diesel for road transport from IEA World Energy Balances (2020) for the same years and multiplied them by the aggregated data from SES. Assuming that the SES aggregated coverage of fuel consumption for the transport sector includes domestic shipping for freight transport, we then subtracted diesel consumption in the domestic shipping sector as retrieved from IEA World Energy Balances (2020) for the same years, from this estimated aggregated diesel consumption to get a more accurate depiction of the diesel consumption for road transport.

We also obtained annual vehicle population statistics[58] of cars, taxis, motorcycles, buses as well as goods and other vehicles (assumed to be freight trucks) by each fuel type between 2006-2022 from the Annual Vehicle Statistics by LTA[59] (LTA, 2022). Fuel economy data (in l/100km or $m^3$/km or Wh/km) for car, bus and light duty truck models are available from the LTA OneMotoring Fuel Cost Calculator[60] website. Generally, the average fuel economy was derived for each mode of vehicle by fuel type and its corresponding VES band using this dataset. If fuel economy data is unavailable for a particular fuel type for any mode of vehicle, we rely on general SEI estimates instead.

CNG cars and taxis are assumed to be 30% more efficient than their gasoline counterpart[61]. Fuel economy of petrol-CNG cars was derived from halving the average fuel consumption of SEAT Ibiza TGI and SEAT Leon TGI 5D & ST (two petrol-CNG models)[62]. For electric hybrid cars and taxis, instead of categorising them by their VES bands, we categorised them according to whether they are regular electric hybrid or plug-in hybrid. Because only the fuel economy of the petrol/diesel component is available for regular electric hybrids, we assigned gasoline as their primary fuel. However, because both the fuel economy of the petrol/diesel component and electrical energy for plug-in electric hybrids are available, we assigned electricity as their primary fuel.

Regarding goods and other vehicles, although information on the population of light-duty vehicles (LDV) and the population of heavy-duty vehicles (HDV) in Singapore are reported in the Annual Vehicle Statistics, there is no breakdown of fuel types for LDVs and HDVs separately. Moreover, only fuel economy data on light duty vehicles is available in the LTA OneMotoring fuel economy dataset. Therefore, we first derived the scale difference between the average fuel economy of LDVs and HDVs (gasoline and diesel) using the WRI GHG Emission Factors Compilation for U.S. vehicles and applied it to the average fuel economy of gasoline and diesel LDVs in Singapore according to the LTA OneMotoring fuel economy dataset to get an estimate for the average fuel economy of HDVs in Singapore. We then derived an average weighted fuel economy for LDVs and HDVs combined based on the average ratio of LDV to HDV population between 2013-2023 in Singapore. Because no information on the fuel economy of electric HDVs in available in the same U.S. dataset, the fuel economy of the Tesla Semi was used[63] in tandem with the fuel economy of electric LDVs as derived from the LTA OneMotoring fuel economy dataset, weighted accordingly based on the average proportions of the LDV to HDV population.

As there is no domestic fuel economy data available for CNG cars, CNG and gasoline buses, CNG freight trucks, as well as for gasoline and electric motorcycles in the LTA OneMotoring fuel economy dataset, we used the ones in the WRI GHG Emission Factors Compilation

[58] Because the proportion of each type of vehicle by fuel type is unavailable for tax exempted vehicles, we exclude this group of vehicles from our vehicle population data inputs.
[59] https://datamall.lta.gov.sg/content/datamall/en/static-data.html
[60] https://vrl.lta.gov.sg/lta/vrl/action/pubfunc?ID=FuelCostCalculator
[61] https://apea.org.uk/fcev-vs-cng-vs-lng-vs-ev-which-is-the-right-future-fuel-for-you/
[62] https://www.seat.sg/company/easy-mobility-cars/future-today/move-and-green/tgi
[63] https://www.electrive.com/2023/08/15/pepsico-cites-consumption-of-1-1-kwh-km-for-tesla-semi/

and/or relied on default SEI estimates. Petrol-CNG buses and freight trucks are also assumed to have half the sum of the energy intensity of gasoline buses/trucks and that of CNG buses/trucks. We conjecture that diesel-electric buses[64] and freight trucks have 25% lower energy intensity compared to diesel ICE ones (using diesel as the primary fuel) as electricity consumption data was unavailable (Byun and Choi, 2021).

In the historical period and in the projection period where data is unavailable, IPCC Tier 1 default emission factors were used to approximate the average environmental loading factors from fuel consumption in the goods producing industries, transport, services and residential sectors. To calculate the average environmental loading factor for each mode of vehicle by fuel type in the projection period of the transport sector, total annual loading was used, whereby the adopted emission factors (g/km) were multiplied by the corresponding vehicle-km and then by the shares of each vehicle type by type of fuel and their corresponding VES bands. Because this method of calculating emissions is independent of energy consumption, we also include calibration factors for road transport emission factors to ensure scale equivalence between emissions in the historical and projection periods for road transport.

For the transport sector (projections), $CO_2$ emission factors (g/km) were derived from the Fuel Cost Calculator dataset that are available for individual vehicle models and the LTA Vehicle Emission Schemes[65] website for hydrocarbon, carbon monoxide, nitrogen oxides and Particulate Matter (PM) 10 emission factors. The average $CO_2$ emission factors for each mode of vehicle by fuel type and their corresponding VES bands were then derived in the same way as we did for the fuel economy using the Fuel Cost Calculator dataset, and the average or minimum/maximum of the emission threshold for each VES band for the other types of pollutants were applied to cars and taxis irrespective of their fuel types. Interestingly, the dataset shows that electric cars even in the A1 band have assigned $CO_2$-equivalent emission factors even though EVs do not generate tailpipe emissions, which indicates that the upstream $CO_2$ emissions produced by electricity generation from fossil fuels to charge the EVs could have been accounted for[66]. However, to avoid double counting of emissions as upstream emissions are already accounted for in the electricity generation sector, we excluded the $CO_2$ emission factors of all EVs in our data inputs.

For vehicles which do not have direct estimates of emission factors for a particular pollutant, before relying on IPCC Tier 1 default emission factors, we used estimates from the wider literature such as the WRI GHG Emission Factors Compilation (with similar assumptions to how we processed data for the fuel economy) or from scientific articles (e.g., Clairotte et al., 2020; Lowell, 2012; Pratti et al., 2012; Seo et al., 2020; Xu et al., 2017)[67]. We assumed that Petrol-CNG buses and freight trucks have half the emission factors of petrol and CNG buses/trucks combined. As there is no emission factor data available for gasoline buses in Singapore, the scale difference between the average emission factor of diesel and gasoline buses as reported in the WRI GHG Emission Factors Compilation was applied to the average emission factor of diesel buses in Singapore.

For the domestic shipping sector, we assume that all vessels use diesel historically (Ju and Hargreaves, 2021). In Singapore, there are around 2,300 harbour craft (1,600 with engines) operating within Singapore waters, consisting of 11% tankers, 29% supply vessels, 7% passenger boats, 16% tugboat, and 37% others. A SP vessel travels 66.2 nautical miles

[64] https://landtransportguru.net/hybrid-buses-in-singapore/#:~:text=As%20a%20result%2C%20hybrid%20buses,figure%20of%2025%20per%20cent

[65] https://onemotoring.lta.gov.sg/content/onemotoring/home/buying/upfront-vehicle-costs/emissions-charges.html

[66] https://www.nea.gov.sg/media/news/news/index/enhanced-vehicular-emissions-scheme-to-be-extended-with-tightened-pollutant-thresholds#:~:text=%5B1%5D%20To%20account%20for%20the,hybrid%20electric%20vehicles%20(PHEVs).

[67] Gasoline hybrid emission factors were used for diesel-electric LDVs due to unavailable diesel hybrid emission factors. We assume that CNG trucks emit 15% less $CO_2$ than diesel trucks and that this is the case even for LDVs. Average concentration of $CO_2$, NOx, PM 2.5 emissions of hybrid buses is lower by 8%, 44% and 51% respectively compared to diesel buses. Tail-pipe $CO_2$ emissions from CNG buses are assumed to be 22% lower than $CO_2$ emissions from diesel buses.

(NM) in a 5-day period. Due to lack of data on vessel travel schedules, we assume that this is the distance travelled by all vessel types in a week, and that fuel consumption per NM travelled (energy intensity) is the same for all fuel types (Xiao, 2022). Because fuel consumption per distance varies according to vessel speed category, we obtained average values of the speed of each domestic vessel type[68] and matched them to the appropriate fuel consumption per distance values.

For future shipping fuels, we consider electric-hybrid, CNG, fully electric, biodiesel, methanol, very low sulphur fuel oil (VLSFO), low-carbon ammonia liquid and blended biofuel. Emission factors for domestic shipping are directly transferred from other foreign literature where data is available and only tank-to-propeller emissions are considered, assumed to be the same for all vessel types. Based on Liu, M. (2020), hybrid-fuelled ships have a lower GHG impact of about 18.6% compared to marine gasoline oil (equivalent to diesel).

Due to the lack of emission factor data for biofuels, we had to approximate by taking an average of SOx and PM reductions by 65% and an average net NOx increase by 119% (Zhou et al., 2020). For VLSFO, SOx and SO2 values for heavy fuel oil (HFO) are adjusted based on the fact that VLSFO has 7 times less sulphur content that HFO[69]. For blended biofuel, we refer to B24 daily assessment, which is made up of 24% used cooking oil methyl ester (UCOME), assumed to be biodiesel and 76% very-low sulphur fuel oil (VLSFO)[70]. Other emission factors are referenced from a variety of sources such as Fridell et al. (2020), Virginia Commercial Offshore Wind Farm (2015), International Marine Organization (2016), Laugen, L. (2013), Hsieh and Felby (2017), Comer and Osipova (2016) and Karvounis et al. (2024).

A direct growth constrain function was assumed to apply to electricity intensity of the railway system (total energy consumption divided by aggregate passenger distance travelled) but with a 15% reduction to the projected values, assuming that the electricity consumption of the transport sector as reported in the SES is referring to that of the railway system only due to data unavailability on a further breakdown on the modes of electric transport that are considered. This aligns with Singapore's metro operator SMRT having joined signalling supplier Thales in the Next-Generation Green CBTC project, which aims to cut the consumption of electricity by trains on the North-South and East-West lines by 15%[71].

## 5.2 Technology costs (for optimisation only)

Capital, operating and maintenance (fixed and variable) costs for natural gas OCGT and CCGT, nuclear, WTE, geothermal, biomass and coal-fired plants, as well as solar PV and BESS, were directly derived from the 2023 Annual Technology Baseline (ATB) by the U.S. National Renewable Energy Laboratory, which includes costs from the base year 2021 which are projected to 2050.

According to the Energy Market Authority's (EMA) vesting price parameters for generation facilities which approximates the long run marginal cost of a theoretical new entrant that uses the most economic generation technology in operation in Singapore, CCGT units based on "F" class gas turbines are recommended (EMA, 2022). Therefore, the costs of a moderate natural gas combustion turbine and CCGT (F-Frame) were assumed to apply to

68 www.marinetraffic.com
69 https://www.alfalaval.sg/industries/marine-and-transportation/marine/oil-treatment/fuel-line/marine-fuels-in-the-low-sulphur-era/#:~:text=Very%2Dlow%20sulphur%20fuel%20oil,Heavy%20fuel%20oil%2C%20max%203.50%25
70 https://www.argusmedia.com/en/press-releases/2023/20230131-argus-launches-worlds-first-biofuel-blended-ship-bunker-price
71 https://www.railjournal.com/passenger/metros/singapore-chooses-green-cbtc-to-cut-metro-energy-consumption/#:~:text=Partnership%20with%20Thales%20aims%20to%20cut%20energy%20use%20by%2015%25.&text=SINGAPORE%20metro%20operator%20SMRT%20Trains,%2DWest%20lines%20by%2015%25.

natural gas-fired (OCGT and CCGT) plants in Singapore. For diesel generators, the average of the maximum and minimum costs from the EU's Sustainable Energy Handbook (2016) were used (Farnoosh, 2022).

For solar PV, costs of solar utility PV (Class 2 moderate) were used as inferred from the Singapore Civil Defence Force (SCDF) submission requirements for solar PV installations on roofs in 2015[72].

When used with NEMO, LEAP can simulate energy storage. For BESS, costs for moderate utility-scale battery storage for 6 hours were used[73], considering the costs of a lithium-ion battery[74], adapted from the U.S. HydroWIRES Report and a discharge period of 4 to 8 hours (Somasundaram et al., 2020).

For geothermal, the ATB defines flash resources as those with temperatures at or above 200°C and binary resources as those with temperatures from 110 to <200°C. In Singapore, the temperature is 50 °C in hot spring, > 90°C around wet soil, and 163°C at unknown depth (Romagnoli and Massier, 2023). Because surface temperatures are not high enough to deploy traditional geothermal systems, deep geothermal systems like the Advanced Geothermal System (AGS) and Enhanced Geothermal System (EGS) that tap on heat from hot dry rocks found at depths beyond 3km, and at temperatures greater than 150°C are more viable. Therefore, costs of binary moderate deep EGS were used.

Because advanced nuclear technologies such as small modular reactors (SMR) are preferrable compared to conventional large-scale reactors in Singapore, the costs of a moderate SMR are used.

The costs of moderate dedicated biopower were assumed to apply to WTE plants. For coal and biomass cogeneration, the average of the combined costs of a moderate coal-new generator and moderate dedicated biopower were used.

EMA recommended that all new and repowered generation units should be advanced CCGTs (i.e. H-class or equivalent) to meet higher emission standards and to be at least 30% volume hydrogen-ready (EMA, 2023a). Therefore, for hydrogen and ammonia power plants, costs of an advanced natural gas CC (H-Class) were used.

For electricity imports, the capital cost and variable operating cost (assumed to be equivalent to amortised operating cost) were estimated based on NREL's cost of energy transmission via high-voltage DC cables ($1502/mile-MW and $6.5/MWh/1,000 miles) and the cumulative distances from Singapore to the various ASEAN countries[75] to which it has obtained conditional approvals to import electricity from between 2022-2035 (DeSantis et al., 2021).

Fossil-fuel power generation technologies assumed to be retrofitted with carbon capture storage (CCS) technologies from 2030 as per the BAU scenario would result in an increase in the capital, operating and maintenance costs. Although we only model 5% emissions abatement in 2030, improving to 10% in 2050 (50% for WTE plants), the costs of a minimum 90% CCS integrated retrofit for fossil fuel-generation technologies are used as per cost data availability.

For natural gas, because only costs for moderate CCGT (F-Frame) with CCS implementation that can reduce emissions by 90% are available in the 2023 ATB, we assume that the

[72] https://www.scdf.gov.sg/firecode/table-of-content/chapter-10-requirements-for-special-installations/clause--10.2
[73] Capital costs ($/kW) = Battery Energy Cost ($/kWh) * Storage Duration (hr) + Battery Power Cost ($/kW). Variable operation and maintenance expenses for BESS are zero.
[74] Currently the most viable technology in Singapore's context in the near future considering capital costs in both $/kW and $/kWh.
[75] https://www.distancefromto.net/distance-from-singapore-country

proportionate increase in costs of CCGT without CCS to that with CCS applies to potential OCGTs (natural gas combustion turbine) with CCS as well, starting from 2030. Because costs of diesel generators with CCS are unavailable, we also assume that they increase proportionately to the increase in costs of CCGT with CCS, starting from 2030.

Given that land-use constraints and environmental concerns would continue to be barriers for Singapore gasification combined cycle (IGCC) adoption for coal generation in small countries, like Singapore, we use the retrofitting costs of a non-IGCC moderate coal-new generator with 90% CCS starting from 2030, keeping the moderate dedicated biopower costs' component constant (Wang et al., 2018).

A study in the context of the U.S. shows that the capital cost of conventional WTE plants to WTE plants could increase by 1.6 times with CCS implementation (Zeman, 2010). We assume this proportionate increase applies to the costs of moderate dedicated biopower, starting from 2030.

## 5.3 Fuel costs (for optimisation only)

For natural gas import prices, we use Indonesian spot prices for our piped natural gas (PNG) imports[76] with total import volume data from SES 2023 as other countries such as Malaysia forms about 1/7000 of Singapore's piped natural gas imports, as compared to Indonesia (Malaysian Gas Association, 2016). As Singapore imports liquid natural gas (LNG) mostly from US and Australia, we retrieved US spot prices from the US Energy Information Administration[77] and Australian spot prices were retrieved from Australian Energy Regulator[78]. Because there is no spot price index available for Australian LNG, we use a simple average of the prices at the 4 Australian regional gas markets. Since Australian data only stretches back to 2011, we use purely US prices for the LNG imports for years up to 2010. LNG import shares for Australia and US in 2021 were 3 billion m$^3$ and 700 million m$^3$ respectively (BP, 2022). As we do not have access to historical data for the import shares of LNG between US and AUS, we compute a weighted average of LNG import price based on this ratio.

For coal import price, since Singapore imports 96% of its coal from Indonesia[79], we used the Indonesian coal reference price (HBA) for our import cost of various coal types (bituminous, anthracite, etc) since Indonesia export prices for coal are set based on this reference price, retrieved from the Directorate General of Mineral and Coal database via CEIC. For biomass, the average wood pellet import prices from 2013-2022 were retrieved from IndexBox[80]. For oil and diesel, we used the historical and projected estimates from the 7$^{th}$ ASEAN Energy Outlook 2022 between 2020-2050 in terms of $/MWh (ACE, 2022). Nuclear fuel costs were also retrieved from the 7$^{th}$ ASEAN Energy Outlook 2022. MSW fuel costs were estimated to be 4 cents per kWh[81].

Based on IEA estimates, the cost of low-carbon hydrogen production ranges from $3.4/kg to $12/kg and the levelized cost of hydrogen from fossil fuels was estimated at $1/kg to $3/kg in 2021[82]. Therefore, we took the average of these estimates for the costs of green

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76 https://www.indexmundi.com/commodities/?commodity=indonesian-liquified-natural-gas&months=360
77 https://www.eia.gov/dnav/ng/hist/rngwhhdA.htm
78 https://www.aer.gov.au/wholesale-markets/wholesale-statistics/gas-market-prices
79 https://trendeconomy.com/data/h2/Singapore/2701#:~:text=Indonesia%20with%20a%20share%20of%2096%25%20(58%20million%20US%24)
80 https://www.indexbox.io/search/wood-pellets-price-singapore/
81 https://www.epa.gov/smm/energy-recovery-combustion-municipal-solid-waste-msw
82 https://energynews.biz/singapores-ambitious-plan-for-50-hydrogen-by-2050/#:~:text=The%20ambitious%20goal%20is%20for,%243.4%20to%20%2412%20per%20kilogram

hydrogen ($66.60/GJ) and hydrogen blend ($17.30/GJ)[83]. Regarding low-carbon ammonia, indicative offers for delivery to Singapore under long-term contracts of 10-20 years were around $300-$400/metric tonne for blue ammonia from the Middle East or US$700-$800/metric tonne for green ammonia from India and Australia[84], which averages to about $34.70/GJ considering the shares of blue and green hydrogen used to synthesise low-carbon ammonia in our model.

For imported electricity prices, due to data unavailability on the purchase price in Singapore from Laos, Malaysia, Indonesia, Vietnam and Cambodia, we had to refer to the selling prices of imported renewable electricity from various sources (Table 1).

**Table 1: Price of renewable electricity purchased from selected neighbouring ASEAN countries**

| Country | Price of renewable electricity (USD) | Source |
|---|---|---|
| Laos | $0.0695/kWh (hydro-generated) | https://theinvestor.vn/vietnam-to-buy-electricity-from-7-laos-wind-power-projects-d8745.html |
| Malaysia | $0.04654/kWh | https://www.nst.com.my/news/nation/2023/07/931157/renewable-energy-set-218-sen-kwh |
| Indonesia | $0.149/kWh (solar PV-generated) | Hermawan et al. (2023) |
| Vietnam | $0.098/kWh (offshore wind-generated) | https://vietnamnews.vn/economy/1657789/ministry-proposes-removing-fit-for-more-competitive-renewable-energy-prices.html |
| Cambodia | $0.054/kWh (solar PV and wind-generated) | https://chinadialogue.net/en/energy/opinion-cambodia-can-secure-reliable-electricity-without-new-coal-2/ |

[83] Conversion rates from kilograms to gigajoules and from tonne to gigajoules for hydrogen and ammonia respectively estimated from: https://www.iea.org/reports/the-role-of-low-carbon-fuels-in-the-clean-energy-transitions-of-the-power-sector/executive-summary
[84] https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/energy-transition/112223-rising-blue-ammonia-production-costs-close-in-on-green-pathways

## 5.4 Storage (for optimisation only)

We model battery energy storage within the electricity generation module. BESS stores the excess electricity that is produced by another process and then dispatches it to meet electricity demand at times of the day when it is required. The 200 MW (BAS) plus 7.5 MW (BAU) of exogenous capacity modelled are equivalent to the maximum power output of Southeast Asia's largest utility scale BESS on Singapore's Jurong Island that was operational at the end of 2022 and Singapore’s first floating BESS to be launched in 2024 respectively, with an assumed round-trip efficiency of 85% as per the 2023 ATB. In addition, there are storage-specific variables that can be used for optimisation calculations (starting charge, minimum charge, full load hours and energy carryover rules).

Given that the threshold stored energy of lithium-ion batteries is 20 kWh and the maximum stored energy is 600 kWh[85] as per SCDF guidelines, we estimate the minimum charge allowed for the storage process and the charge at the start of the modelling period to be 3.33% of the full charge. The amount of full load hours is estimated to be 1.425 hours (285MWh/200MW) with reference to the BESS on Jurong Island. This implies that once the batteries in this ESS are fully charged, they can be used for about 1 hour 26 minutes at their full load before they are discharged completely[86]. In addition, in terms of energy carryover rules, we allowed energy stored in one year and in a particular daily period to be able to be used in subsequent years and daily periods respectively.

[85] https://www.scdf.gov.sg/firecode/table-of-content/chapter-10-requirements-for-special-installations/clause-10.3

[86] The full load hours (energy/power) of the expanded BESS capacities are assumed to be the same as that of the current BESS in Jurong at this stage due to data unavailability, so it is likely to be an underestimate as the energy-to-power ratio might be improved in the future.

# 6. SCENARIOS MODELLED (SIMULATION)

In our simulation model, we have incorporated 4 scenarios. To begin with, we have the Baseline (BAS) scenario, which represents the case without any policies in place[87], except for the MEPS in the residential demand sector, vehicle growth policy in the transport demand sector and electricity imports via the LTMS-PIP in the power sector. Next, we have the Business-As-Usual (BAU) scenario which consists of selected existing policies and targets pertaining to the power generation, transport, industry and residential sectors. Finally, we have two Highly Ambitious (HA) scenarios which serve as an extension of the BAU scenario pertaining to the power sector in developing a more renewable energy portfolio in the future.

Exogenous capacities refer to capacity additions/subtractions of fuel transformation technologies which are specified externally and automatically added to the model without being determined by internal calculations or optimisation. By contrast, the endogenous capacities as specified to the model are situationally added to meet module requirements and maintain the planning reserve margin according to the built order of generation processes[88].

When each endogenously added process reaches its specified lifetime[89], it will be automatically retired (and additional processes added if necessary). All current policy targets pertaining to power generation under the BAU scenario are represented as exogenous capacity (Table 2). We also include mitigation impacts on emissions[90] and improvements in resource properties of fuel combustion where data is available.

The first HA scenario (HA1) assumes that the existing capacities of natural gas CCGTs remains the same until 2050. It then assumes that hydrogen-ready power generation capacity can grow linearly from 2026 and fully accommodate the planned capacities of the two new natural gas OCGTs to be built by 2025 and the existing capacities of CCGTs when they retire following a negative linear growth function by 2050. Oil-fired generators are also assumed to be retired in the same way by 2050. WTE plants are also expected to be gradually phased out after the construction of the IWMF in 2027, leaving only a generation capacity equivalent to the IWMF of 270 MW by 2050.

The share of coal burned in coal and biomass cogenerators is expected to be zero by 2050, which is equivalent to the TMUC being converted from a coal to fully biomass power plant. The generation capacity addition of the proposed low-carbon ammonia power plant in 2027 is also exogenously determined by taking the average of the estimated generation capacity of 55 MW and 65 MW (60 MW). The installed solar PV capacity target of 2 GW that is assumed to be attained by 2030 in the BAU is in turn assumed to grow linearly to its maximum technical potential of 8.6 GW in 2050.

[87] The state of development regarding certain features of the energy demand and supply sectors are expected to remain constant in all projected years in cases where growth rates/additions/subtractions etc. are not specified.
[88] See Table 2 for which policies are modelled under exogenous capacity and Table 3 for which policies are modelled under endogenous capacity.
[89] Assuming that OCGTs and CCGTs have a 25-year lifespan, solar PV systems, WTE and geothermal power plants have a 30-year lifespan, coal-fired power plant has a 45-year lifespan, nuclear has a 60-year lifespan, and BESS has a 15-year lifespan.
[90] With reference to 2020 $CO_2$ emissions data from fuel combustion by sector, sourced from the Greenhouse Gas Emissions from Energy by the International Energy Agency.

Electricity imports of 338 MW from 2032 which is a value equivalent to the annual import amount from Indonesia's Riau Islands[91] plus 1/19 of the import target from Sarawak by 2032 (which sums up to 1 GW from 2032-2050), 50 MW of geothermal generation capacity from 2040 which is equivalent to the generation capacity analysed by Oliver (2010), and 300 MW of nuclear plant capacity from 2040 which is equivalent to the maximum generation capacity of a SMR, are all modelled under endogenous capacity.

Regarding the second HA scenario (HA2), while fossil fuels are similarly intended to be phased out in the energy mix with lesser waste incineration in the future, one difference from HA1 is that HA2 does not automatically assume that existing and new natural gas OCGTs and CCGTs are displaced by hydrogen power generators by 2050. Instead, under endogenous capacity, we include 200 MW of hydrogen generation capacity addition from 2027 which is equivalent to 1/3 of the upcoming hydrogen-ready plant's generation capacity to be built by 2026 in the BAU. The 60 MW generation capacity addition of the proposed low-carbon ammonia power plant in 2027 is also endogenously determined.

330 MW of solar PV generation capacity addition is also modelled under endogenous capacity from 2031 which is equivalent to the average annual increase in annual generation capacity derived by dividing the difference between 8.6 GW and 2 GW by 20 years (2030-2050)[92]. These endogenous capacities (solar PV, hydrogen and low-carbon ammonia power generators) are added on top of the other endogenous capacities (geothermal and nuclear power generators as well as electricity imports) that are specified in HA1.

Suppose that, in HA2, all the available endogenous capacities of each technology have been added up in a given year e.g., 2040 but are still insufficient to meet the planning reserve margin at the minimum. As such, a further 330 MW of solar PV generation capacity will be added again, followed by 200 MW of hydrogen power generation capacity, 60 GW of low-carbon ammonia, 338 MW of imported electricity, 50 MW of geothermal, 300 MW of nuclear, and so on. In the case of an earlier year e.g., 2030, because only endogenous capacity additions of hydrogen and low-carbon ammonia power generators are specified by that year, only the endogenous capacity additions of these 2 technologies will be added repeatedly until the reserve margin is at least equal to the planning reserve margin. The same also applies to HA1 less the endogenous capacity additions of solar PV, hydrogen and low-carbon ammonia power generators in any given year.

We specified that the electricity generation module can only produce 0.3% of electricity from oil-fired power plants annually starting in the first scenario year in BAS/BAU, which is consistent with the energy mix proportion for petroleum products reported in SES as of the first half of 2023. In HA1/HA2, we specified that this share of petroleum products in the fuel mix will be linearly reduced to zero by 2050. We assumed that all other power generation processes are of equal dispatch priority in all scenarios and thus are dispatched together in proportion to their available capacity starting in the first scenario year.

[91] Ideally assuming that transmission lines operate around-the-clock and that a year has 8760 hours (1 terawatt = 1,000,000 megawatts): 2.5 TWh/8760 * 1,000,000 ≈ 285 MW

[92] Also see Table 4 for a summary of the comparison between HA1 and HA2 with regards to generation capacity changes.

Table 2: Exogenous policies modelled in key sectors

| Sector | Processes | Exogenous policies modelled | Scenario |
|---|---|---|---|
| Power generation | WTE incineration plants | The Integrated Waste Management Facility (IWMF), built by 2027, has a generation capacity of 270 MW. | BAU |
| | | Existing WTE plants except the IWMF to be retired by 2050, retaining only the IWMF's generation capacity (270 MW). | HA1/HA2 |
| | Solar PV power plants | Increase solar energy deployment by five-fold to at least 2 GWp by 2030 with production of low-cost solar cells that have an efficiency of at least 30% from 2026. | BAU |
| | | Deploy up to 8.6 GWp in Singapore by 2050. | HA1 |
| | Natural gas OCGT and CCGT power plants | When the two OCGT generation units are operational in 2025, they can each produce 340 MW of electricity, with natural gas being the primary fuel.<br>• Assuming that existing natural gas OCGT units are retired by 2025 due to exceeding their operational lifetime.<br>New and repowered natural gas plants to be 10% more efficient in 2023 with the introduction of emission standards. | BAU |
| | | Natural gas as a generation fuel to be phased out by 2050. | HA1/HA2 |
| | Oil-fired power plants | Oil as a generation fuel to be phased out by 2050. | HA1/HA2 |
| | Coal and biomass cogenerators | Feedstock fuel share[93] of 70% coal and 30% biomass from 2023 to 30% coal and 70% biomass by 2050. | BAU |
| | | 100% of feedstock fuel share being biomass by 2050. | HA1/HA2 |
| | Electricity imports | 100 MW of renewable hydropower to be imported from Laos from 2022 (LTMS-PIP). | BAS |

[93] See Table 5.

| | | |
|---|---|---|
| | 100 MW imported from Peninsular Malaysia over a period of two years starting in 2024.<br><br>From 2028, 2 GW of solar-generated renewable electricity imported from Indonesia.<br><br>From 2033, 1.2 GW of wind-generated renewable energy imported from Vietnam.<br><br>1 GW of renewable energy (mix of hydropower, solar and potentially wind power) imported from Cambodia, assumed to be from 2035. | BAU |
| Hydrogen power plants | The Keppel Sakra Cogen Plant, a CCGT hydrogen-compatible plant, will be ready by 2026 which can produce up to 600 MW of electricity.<br><br>• Feedstock fuel share[94] will initially include 30% hydrogen blend and 70% natural gas. There will 50% hydrogen blend, 26.3% green hydrogen and 23.8% of natural gas by 2035. In 2050, the share of hydrogen blend will be reduced to 20%, with the addition of 70% green hydrogen into the mix and 10% being natural gas. | BAU |
| | • 50% hydrogen blend, 37.5% green hydrogen and 12.5% natural gas by 2035. 100% of feedstock fuel share being green hydrogen by 2050. | HA1/HA2 |
| | • The two OCGT generation units built in 2025, including existing and upcoming natural gas OCGTs and CCGTs, will be retrofitted to be 100% hydrogen-compatible by 2050. | HA1 |
| Low-carbon ammonia power plants | 60 MW power station built by 2027. | HA1 |
| CCS | 5% carbon capture potential in 2030 for traditional generation processes with significant emissions, up to 10% in 2050.<br><br>• Abatements apply to natural gas OCGT and CCGT (natural gas), oil-fired power plants (diesel), WTE plants (MSW) and coal with biomass generation power plants (coal bituminous). | BAU |
| | Up to 50% carbon capture potential by 2050 for WTE plants.<br><br>• Considering that WTE plants are the only significant emitter in the power sector by 2050 in HA1/HA2. | HA1/HA2 |

[94] See Table 5.

| | | | |
|---|---|---|---|
| | BESS | **ASEAN's largest BESS facility to date with a storage capacity of 200MW/285MWh built in 2022.** | BAS (for optimisation only) |
| | | **A 7.5MW/7.5MWh floating BESS to be launched in 2024.** | BAU (for optimisation only) |
| Transport | | **From 2022, the car and motorcycle population growth rate will be maintained at 0% per annum, while goods vehicles and buses will maintain a 0.25% population growth, until Jan 31 in 2025.**<br>• Between 2012-2025:<br>- Total cars and taxis population could increase at an average of 0.2% annually and projected to 2050 based on this historical trend.<br>- Total bus population could increase at an average of 0.6% annually and projected to 2050 based on this historical trend.<br>- Total motorcycle population could decrease at an average of 0.04% annually and projected to 2050 based on this historical trend.<br>- Total freight truck population could increase at an average of 0.06% annually and projected to 2050 based on this historical trend. | BAS |
| | | **LTA will electrify half of the bus fleet by 2030 and achieve a 100% cleaner energy bus fleet by 2040. From 2040, all vehicles to be of cleaner energy models with the phasing out of ICE vehicles.**<br>• Assumed a linear trend after 2022 in the growth of the fully electric bus population, constituting 50% of all buses by 2030.<br>• Assumed the composition of cleaner energy bus fleet by 2040 to be 70% fully electric and 30% electric hybrid, following a linear growth trend from 50% for fully electric buses after 2030 and for the existing share of electric hybrid buses after 2022.<br>• Assumed a linear trend after 2022 in the decrease of the petrol, diesel, CNG and petrol-CNG car and taxi, bus, motorcycle and freight truck populations, reaching 0% by 2040. | BAU |

| | |
|---|---|
| • Assumed that the composition of car and taxi population consists of 50% electric hybrid and 50% fully electric by 2050[95], following a linear growth function after 2022.<br><br>• Assumed that the projected motorcycle population in 2040 consists of all electric motorcycles, following a linear growth function after 2022.<br><br>• Assumed a 70% electric share of freight trucks and 30% electric hybrid by 2040, following a linear growth function after 2022. | |
| **Assumed that the composition of car and taxi population consists of 50% electric hybrid and 50% fully electric by 2040 and it will be 100% fully electric by 2050 (electric hybrid cars and taxis will reach zero by 2050).**<br><br>**Assumed the composition of bus fleet by 2050 will consist of only fully electric buses (diesel-electric bus population will reach zero by 2050).**<br><br>**Assumed the composition of freight truck population by 2050 will consist of only fully electric freight trucks (electric hybrid freight truck population will reach zero by 2050).**<br><br>• Assumed a linear growth trend of the electric hybrid and fully electric car and taxi populations after 2022, reaching 50% each in 2040, followed by a negative growth trend of electric hybrid cars and taxis to 0% in 2050 but a positive growth trend of full electric cars and taxis to 100% in 2050.<br><br>• Assumed a linear positive growth trend of the fully electric bus and freight truck populations from 70% in 2040 to 100% in 2050, and a linear negative growth trend of electric hybrid bus and freight truck populations from 30% to 0% in 2050. | HA1/HA2 |
| **Cleaner fuels to be used by all types of domestic shipping vessels, from primarily diesel to only 70% diesel, 10% VLSFO, 3% electricity, 3% CNG and 3% blended biofuel, 8% electric-hybrid as well as 1% biodiesel, 1% methanol, and 1% low-carbon ammonia liquid by 2030.**<br><br>**Shares of cleaner fuels improved to 35% VLSFO, 20% diesel, 20% blended biofuel, 6% electric-hybrid, 5% electricity and 5% CNG, as well as 3% biodiesel, 3% methanol and 3% low-carbon ammonia liquid by 2040.** | BAU |

[95] https://www.climateaction.org/news/50_of_singapores_cars_to_be_electric_by_2050

| | | |
|---|---|---|
| | **Shares of cleaner fuels used by the domestic shipping fleet improved to 25% fully electric, biodiesel, methanol and low-carbon ammonia liquid respectively, with the phasing out of diesel, electric-hybrid, CNG, VLSFO and blended biofuel by 2050.** | HA1/HA2 |
| Residential | **NEA enhanced Minimum Energy Performance Standards (MEPS) for refrigerators, clothes dryers and air-conditioners [96] (https://www.nea.gov.sg/media/news/news/index/nea-to-enhance-minimum-energy-performance-standards-(meps)-for-refrigerators-clothes-dryers-and-air-conditioners).**<br><br>• Refrigerator with freezer is assumed to be > 300L to 900L as this is closer to the recommended volume for 4-room households in Singapore, which most residents live in:<br>- Current MEPS: *AEC < [(465 + 1.378 x Vadj tot) x 0.506]*; Enhanced MEPS: *AEC < [(465 + 1.378 x Vadj tot) x 0.427]*<br>- Difference between current and enhanced MEPS taken as: 0.427/0.506 = 0.84 [97] (this percentage is applied to the energy intensity of current refrigerators to derive the reduced energy intensity of efficient refrigerators), assumed to take effect from 2022<br><br>• Assuming casement/window air-conditioners:<br>- Current MEPS: *COP100% ≥ 2.9*; Enhanced MEPS: *COP100% ≥ 3.78*<br>- Difference between current and enhanced MEPS taken as: 2.9/3.78 = 0.77 (this percentage is applied to the energy intensity of current refrigerators to derive the reduced energy intensity of efficient refrigerators), assumed to take effect from 2022 | BAS |
| | **1.4 million residential households in Singapore estimated to be equipped with smart meters over the next few years to facilitate real-time tracking and managing of energy usage which may achieve an average reduction of overall electricity consumption of 2.4%.**<br><br>• Multiply the final energy intensities of cooking, lighting, refrigeration, air-conditioning, water heating, washing machine, television, entertainment boxes, | BAU |

[96] We did not model the effect of MEPS on clothes dryers as we were unable to isolate the proportion of household energy consumption attributed to clothes dryers. Moreover, applying the effect of the MEPS to the entire "Others" category may result in an overestimation as we assumed that "Others" also includes other household appliances such as air purifiers and vacuum cleaners, the latter which has a much higher adoption rate compared to clothes dryers in an average household.

[97] For simplicity, we assumed that *Vadi tot* is the same for both current and enhanced MEPS equations and that they cancel out.

| | | |
|---|---|---|
| | computers, fans and others by 0.976 and assuming a linear function in the adoption of the improved energy intensities by 2030. | |
| | **Phasing out of LPG-powered gas cookers and natural gas-powered water heaters after 2030. All cookers and water heaters to be electric powered by 2050.** | HA1/HA2 |
| Goods producing industries/oil refining | **5% carbon capture potential in 2030, up to 10% in 2050.**<br>• Abatement applied to emissions from refinery gas consumption, which is the largest contributor to emissions out of all fuels in the manufacturing industry and oil refining sector as calculated in LEAP. | BAU |
| | **Up to 50% carbon capture potential by 2050**<br>• Abatement applied to emissions from refinery gas consumption, which is the largest contributor to emissions out of all fuels in the manufacturing industry and oil refining sector as calculated in LEAP. | HA1/HA2 |

Table 3: Endogenous policies modelled in the power generation sector

| Generation processes | Endogenous policies modelled | Scenario |
|---|---|---|
| Geothermal power plants | 50 MW from 2040 [capacity addition as estimated by Oliver (2010)] | HA1; HA2 |
| Nuclear power plants | 300 MW from 2040 (equivalent to the maximum generation capacity of a SMR) | HA1; HA2 |
| Hydrogen power plants | 200 MW from 2027 (equivalent to 1/3 of the upcoming hydrogen-ready plant's generation capacity to be built by 2026) | HA2 |
| Low-carbon ammonia power plants | 60 MW from 2027 (equivalent to the average generation capacity of the proposed low-carbon ammonia plant to be built by 2027) | HA2 |
| Electricity imports | 338 MW from 2032 (equivalent to the annual import amount from Indonesia's Riau Islands plus 1/20 of the import target from Sarawak by 2032) | HA1; HA2 |
| Solar PV power plants | 330 MW from 2031 [equivalent to the average annual generation capacity derived by dividing the difference between 8.6 GW and 2 GW by 20 years (2030-2050)] | HA2 |

*Table 4: Differences in power generation sector policies modelled between HA1 and HA2*

| Generation processes | HA1 | HA2 |
|---|---|---|
| Natural gas OCGT and CCGT power plants | To be phased out by 2050 (exogenous) | To be phased out by 2050 (exogenous) |
| Oil-fired power plants | To be phased out by 2050 (exogenous) | To be phased out by 2050 (exogenous) |
| WTE incineration plants | 270 MW remaining by 2050 (exogenous) | 270 MW remaining by 2050 (exogenous) |
| Nuclear power plants | 300 MW from 2040 (endogenous) | 300 MW from 2040 (endogenous) |
| Geothermal power plants | 50 MW from 2040 (endogenous) | 50 MW from 2040 (endogenous) |
| Electricity imports | 338 MW from 2032 (endogenous) | 338 MW from 2032 (endogenous) |
| Solar PV power plants | 8.6 GW by 2050 (exogenous) | 330 MW from 2031 (endogenous) |
| Hydrogen power plants | Increases from 600 MW in 2026 to accommodate the total combined capacities of new and existing natural gas OCGT and CCGT by 2050 (exogenous) | 200 MW from 2027 (endogenous) |
| Low-carbon ammonia power plants | 60 MW from 2027 (exogenous) | 60 MW from 2027 (endogenous) |

Table 5: Changes in feedstock fuel share for electricity generation—hydrogen power plants and coal and biomass cogenerators (BAU and HA1/HA2)

| Generation process | Year | Feedstock fuel combusted for electricity generation | Feedstock fuel share for electricity generation (BAU) | Feedstock fuel share for electricity generation (HA1 and HA2) |
|---|---|---|---|---|
| Hydrogen power plants | 2026 | Natural gas | 70% | 70% |
| | | Hydrogen blend (30% hydrogen + 70% natural gas) | 30% | 30% |
| | | Hydrogen | 0% | 0% |
| | 2035 | Natural gas | 23.8% | 12.5% |
| | | Hydrogen blend (30% hydrogen + 70% natural gas) | 50% | 50% |
| | | Hydrogen | 26.3% | 37.5% |
| | 2050 | Natural gas | 10% | 0% |
| | | Hydrogen blend (30% hydrogen + 70% natural gas) | 20% | 0% |
| | | Hydrogen | 70% | 100% |
| Coal and biomass cogenerators | 2014 | Coal | 80% | 80% |
| | | Biomass | 20% | 20% |
| | 2023 | Coal | 70% | 70% |
| | | Biomass | 30% | 30% |
| | 2050 | Coal | 30% | 0% |
| | | Biomass | 70% | 100% |

# 7. RESULTS & ANALYSIS (SIMULATION)

In this section, we present and compare our simulation results of the BAS, BAU and the two HA scenarios.

## 7.1 Final energy demand

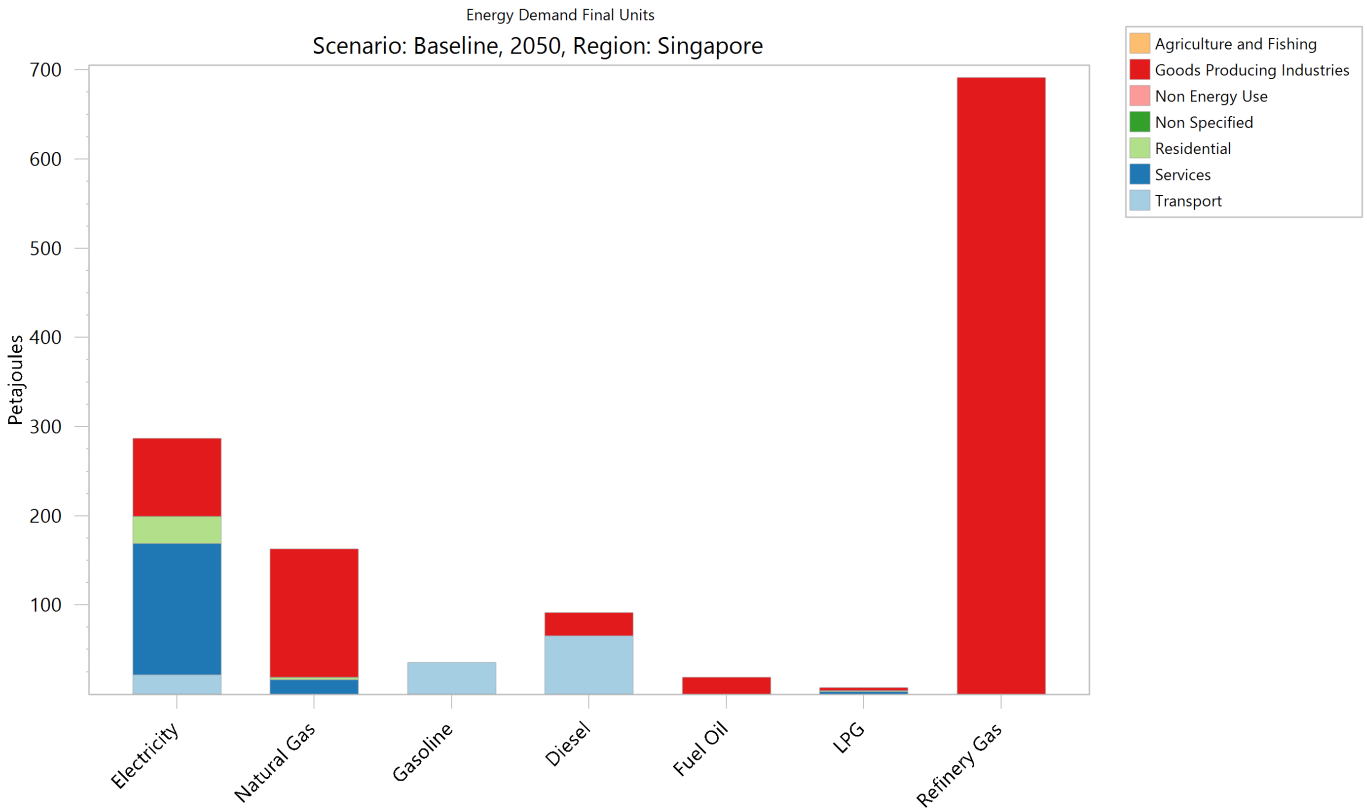


Figure 1: Final energy demand of selected fuels (BAS) in 2050

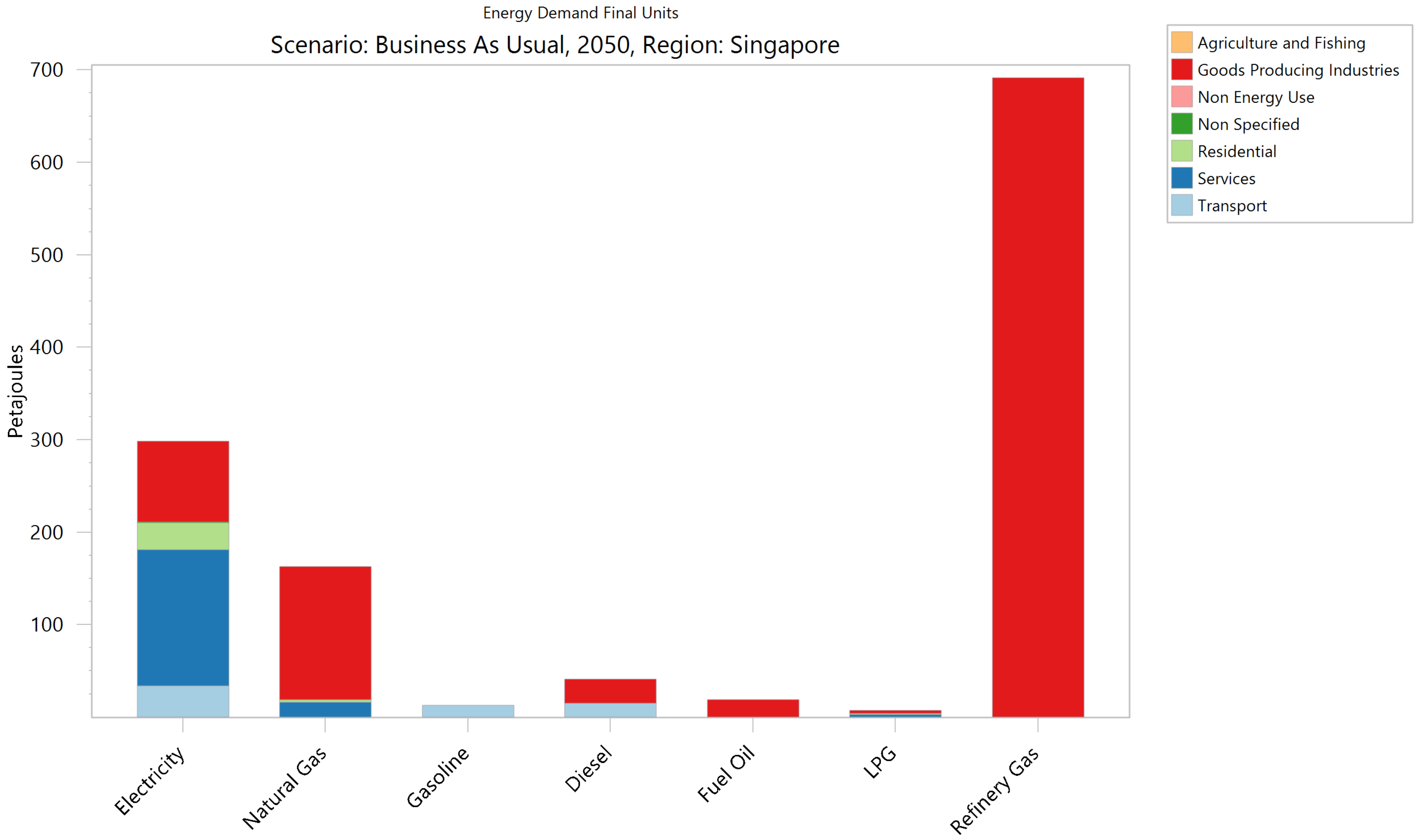


**Figure 2: Final energy demand of selected fuels (BAU) in 2050**

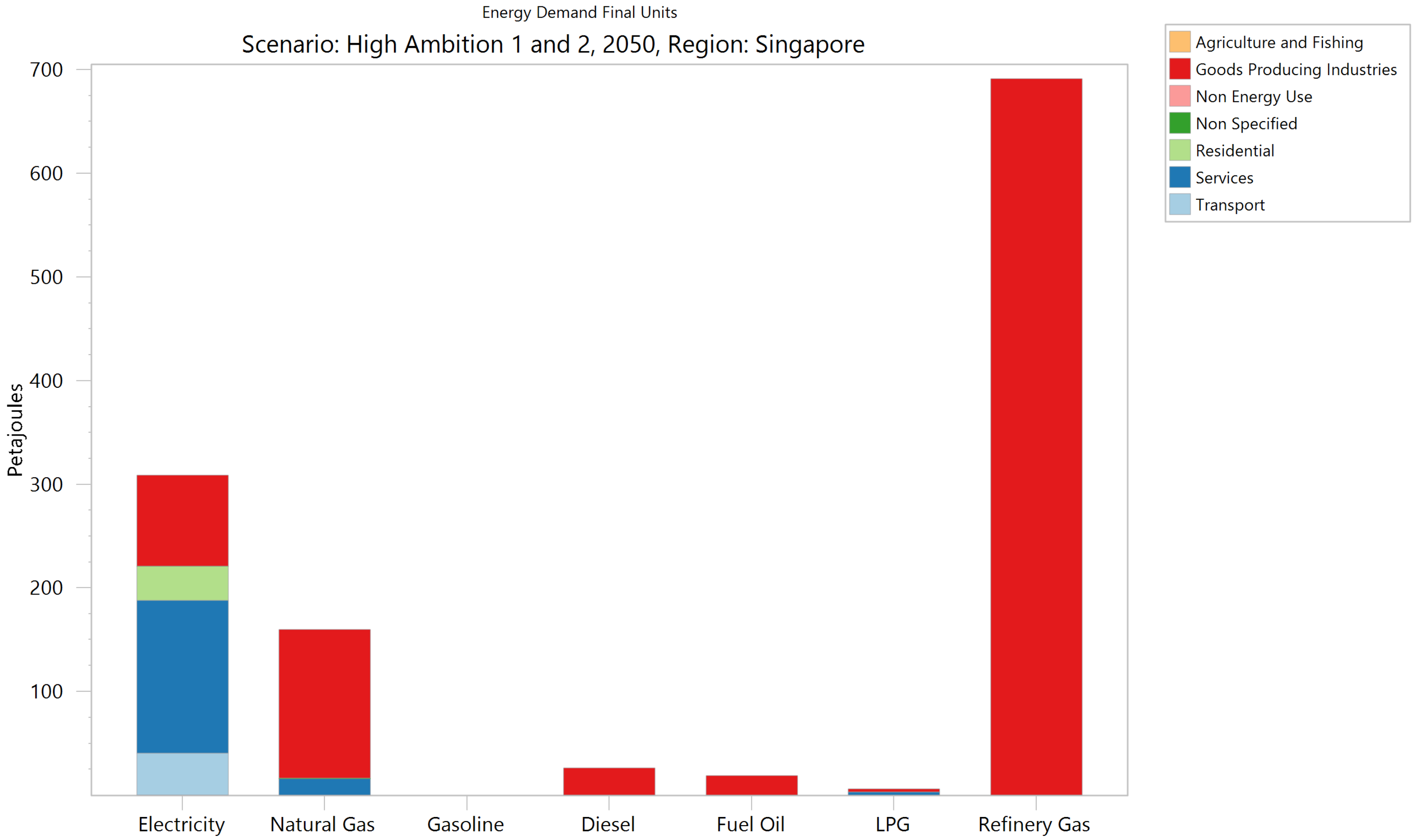


**Figure 3: Final energy demand of selected fuels (HA1 and HA2) in 2050**

First, we focus on energy demand in the domestic energy demand sectors. In the BAS scenario, Singapore's total final energy demand in the domestic energy demand sectors is projected to grow from 743 PJ in 2024, reaching 1346.3 PJ in 2050. In 2050, within the energy use sectors, goods producing industries continue to demand the most energy overall (1023.1 PJ), followed by services (166 PJ), transport (122.3 PJ) and residential (34.4 PJ). Services may be expected to overtake transport in terms of energy demand starting from 2030.

In the BAU scenario, energy demand is projected to reach 1285.3 PJ in 2050. This is higher than APERC (2022)'s estimate of about 1000 PJ in their BAU-equivalent scenario. Total electricity demand of all demand sectors grows at an average annual rate of 1.4%, reaching 298.2 PJ (82.8 TWh) in 2050. Services may be expected to overtake transport in terms of energy demand starting from 2026.

For the projected years, net energy demand reduction of the transport sector in BAU relative to BAS cumulatively amount to 1127.6 PJ, which translates to an average annual 34.7% improvement in energy efficiency. In 2050, road transport (cars and taxis, motorcycles, buses and freight trucks) in BAU has an overall net lower energy demand of 58.4 PJ compared to BAS, where electricity demand is higher by 12 PJ but demand for gasoline, diesel and CNG are lower by 22.6 PJ, 47.7 PJ and 0.2 PJ respectively.

For the projected years, net energy demand reduction of the transport sector in HA1/HA2 relative to BAU cumulatively amount to 154.4 PJ, which translates to an average annual 13% improvement in energy efficiency. In 2050, road transport in HA1/HA2 has an overall net lower energy demand of 20.3 PJ compared to BAU, where electricity demand is higher by 6.8 PJ but demand for gasoline and diesel are lower by 13 PJ and 14.2 PJ respectively.

The passenger (freight) energy intensity of passenger (freight) vehicles can be calculated by the total energy consumption divided by the passenger-kilometres (freight tonne-kilometres), denoted as pkm and tkm respectively. This refers to the total distance driven of each type of passenger (freight) vehicle multiplied by its average capacity utilisation i.e. load factor[98]). For BAU, the passenger energy intensity is calculated to be 0.00387 MJ/pkm and the freight energy intensity is calculated to be 0.667 MJ/tkm in 2050. For HA1/HA2, the passenger energy intensity is calculated to be 0.00185 MJ/pkm and the freight energy intensity is calculated to be 0.330 MJ/tkm in 2050.

In the domestic shipping sector, when HA1/HA2 is compared to BAU in 2050, there is a reduction of 0.8 PJ in the demand for diesel, a reduction of 0.3 PJ for VLSFO, a reduction of 0.04 PJ for CNG and a 0.2 PJ decrease in the demand for blended biofuel. However, there is an increase of 0.09 PJ each in the demand for methanol and low-carbon ammonia liquid, and an increase of 0.2 PJ each in the demand for biodiesel and electricity.

For the projected years, net energy demand reduction of the residential sector in BAU relative to BAS cumulatively amount to 19.3 PJ, which translates to an average annual 2% improvement in energy efficiency. Net energy demand reduction of the residential sector HA1/HA2 relative to BAU cumulatively amount to 7.7 PJ, which translates to an average annual 1.1% improvement in energy efficiency. When HA1/HA2 is compared to BAU in 2050, there is a reduction of 1.1 PJ in the demand for LPG and 2.9 PJ in the demand for natural gas but an increase of 3.3 PJ in the demand for electricity.

[98] Vehicle load factors derived from derived from the International Council on Clean Transportation. For freight trucks, the average ratio of light duty to heavy duty vehicles' population between 2013-2022 was used to derive a weighted average of their load factor.

## 7.2 Share of electricity generation by technology (outputs by feedstock fuel)

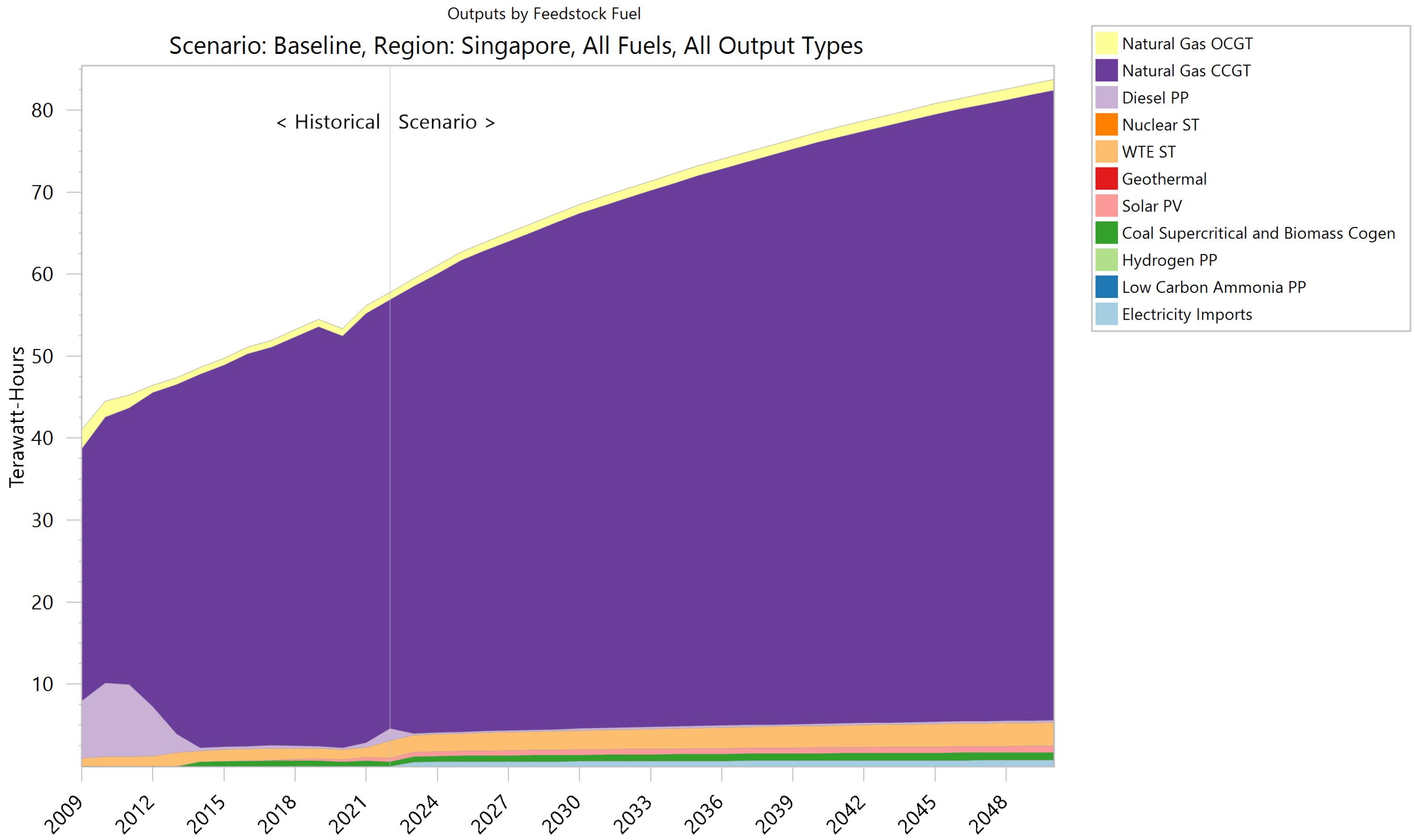


**Figure 4: Absolute share of electricity generation by technology (BAS)**

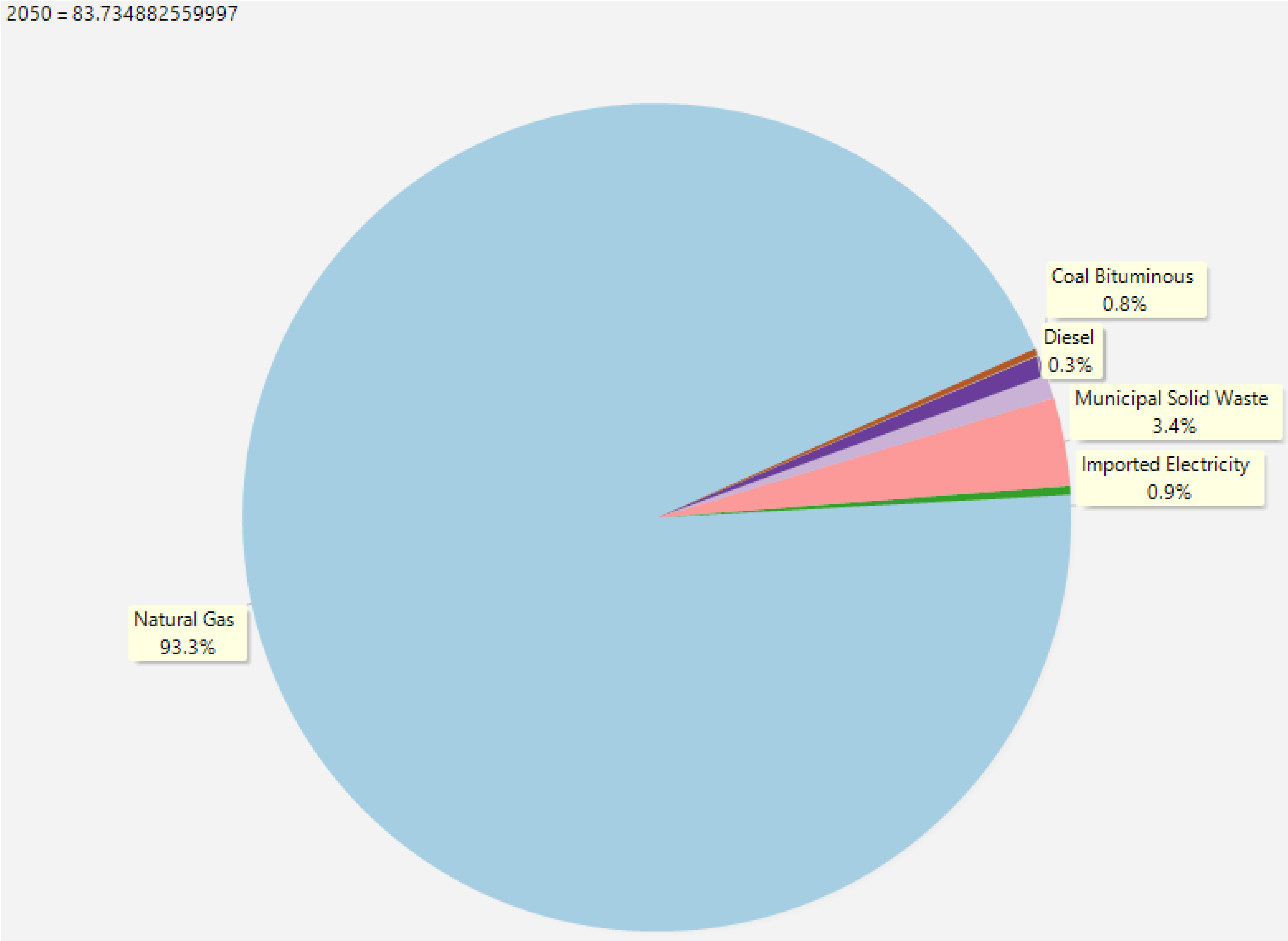


**Figure 5: Percentage share of electricity generation by feedstock fuel type in 2050 (BAS)**

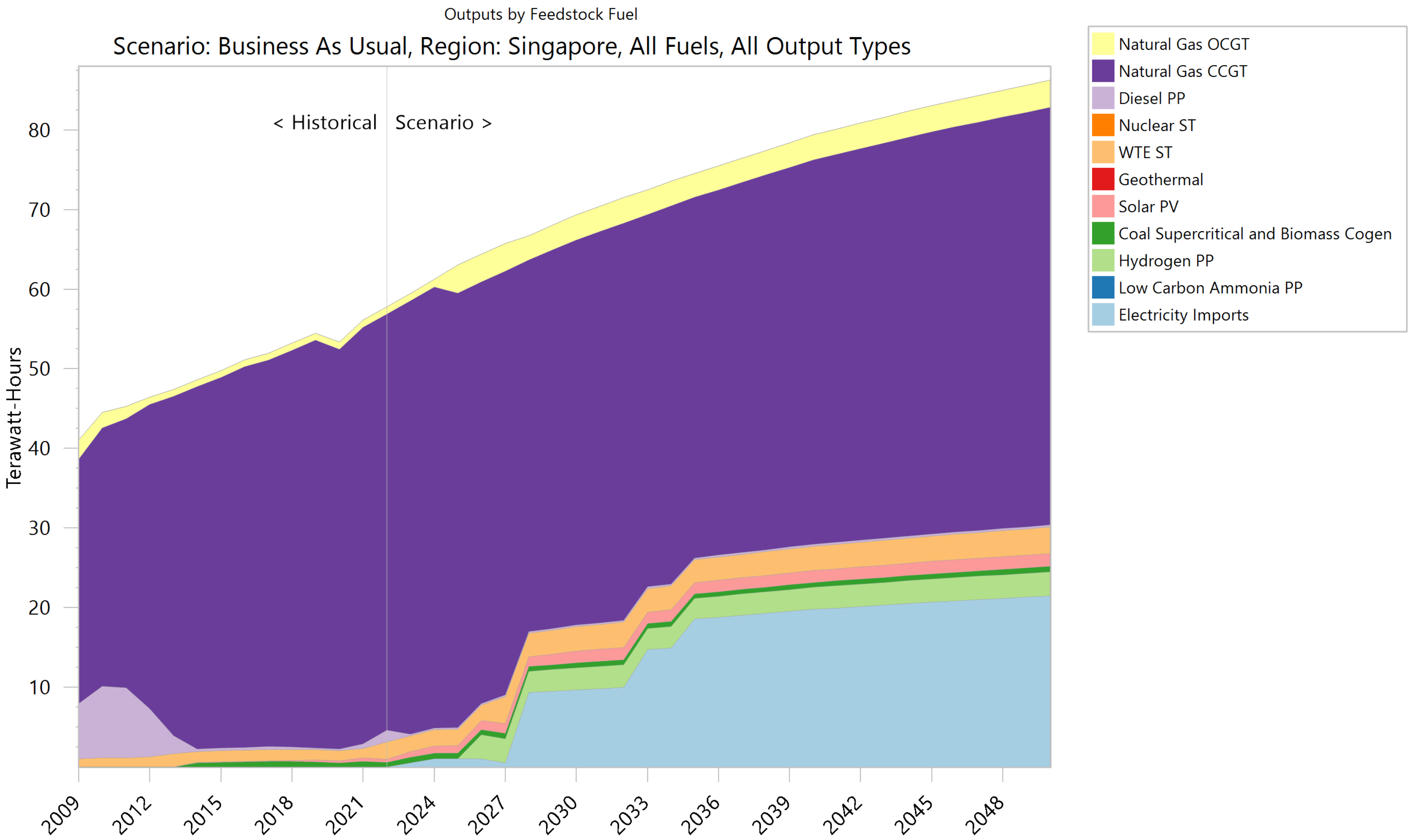


Figure 6: Absolute share of electricity generation by technology (BAU)

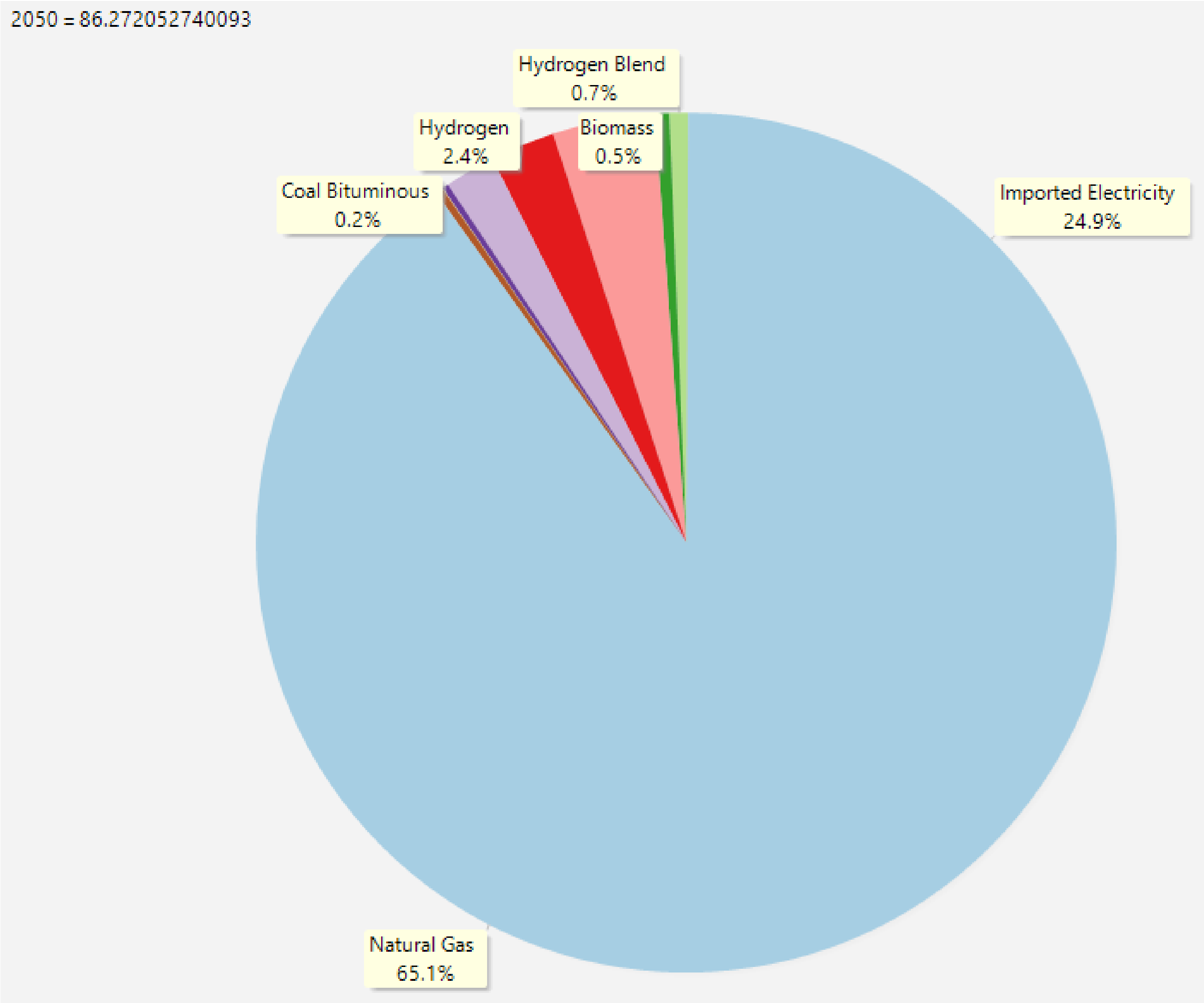


Figure 7: Percentage share of electricity generation by feedstock fuel type in 2050 (BAU)

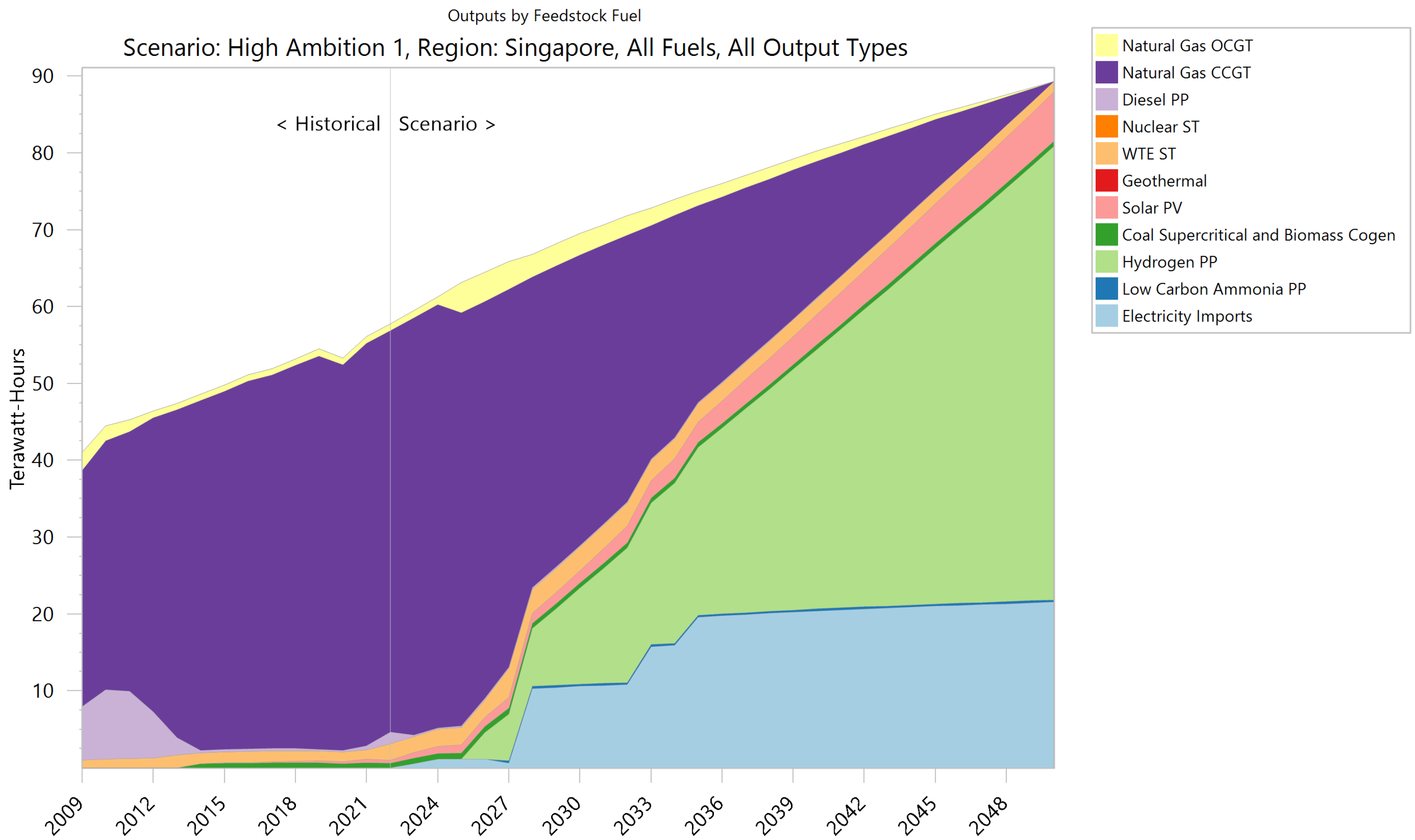


**Figure 8: Absolute share of electricity generation by technology (HA1)**

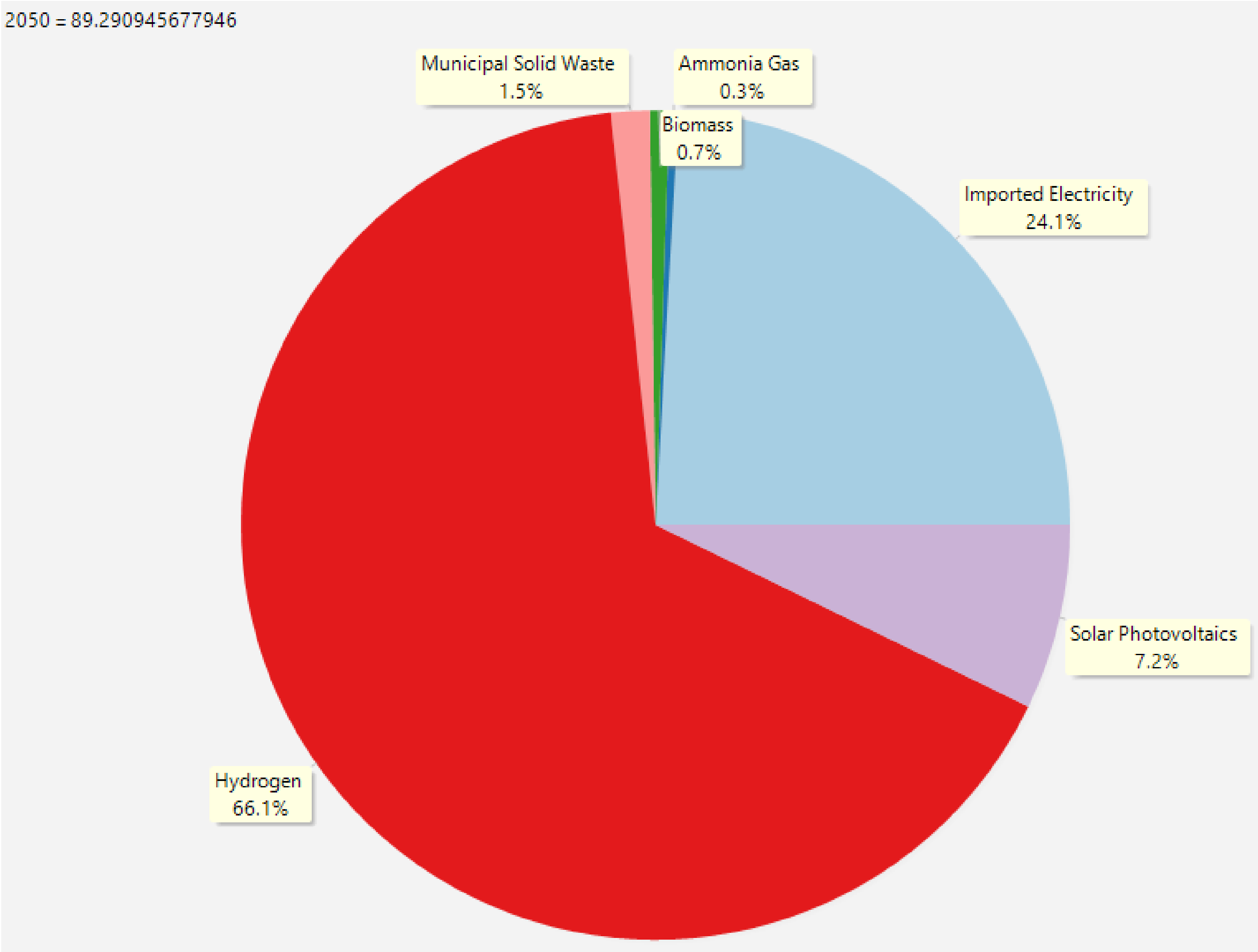


Figure 9: Percentage share of electricity generation by feedstock fuel type in 2050 (HA1)

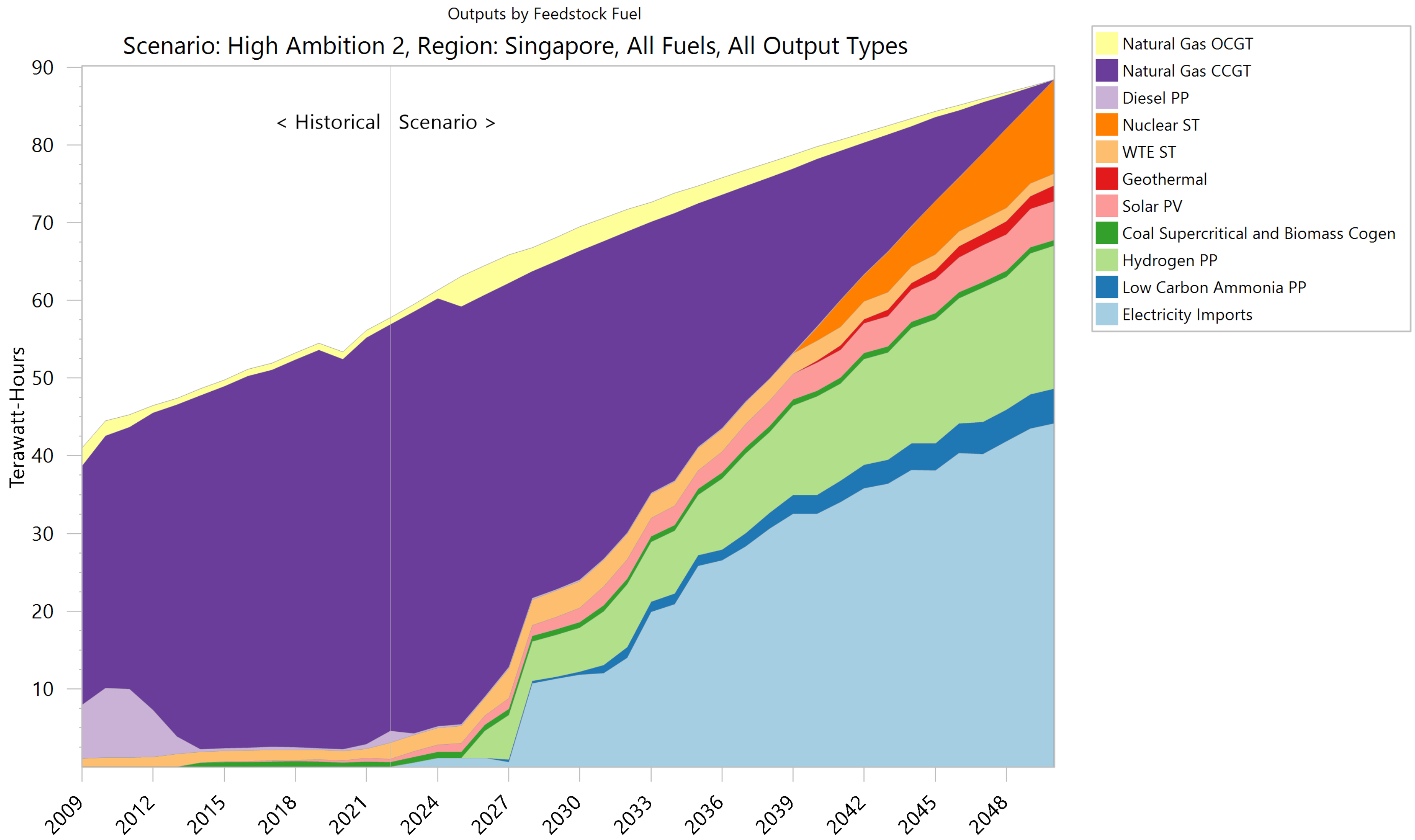


Figure 10: Absolute share of electricity generation by technology (HA2)

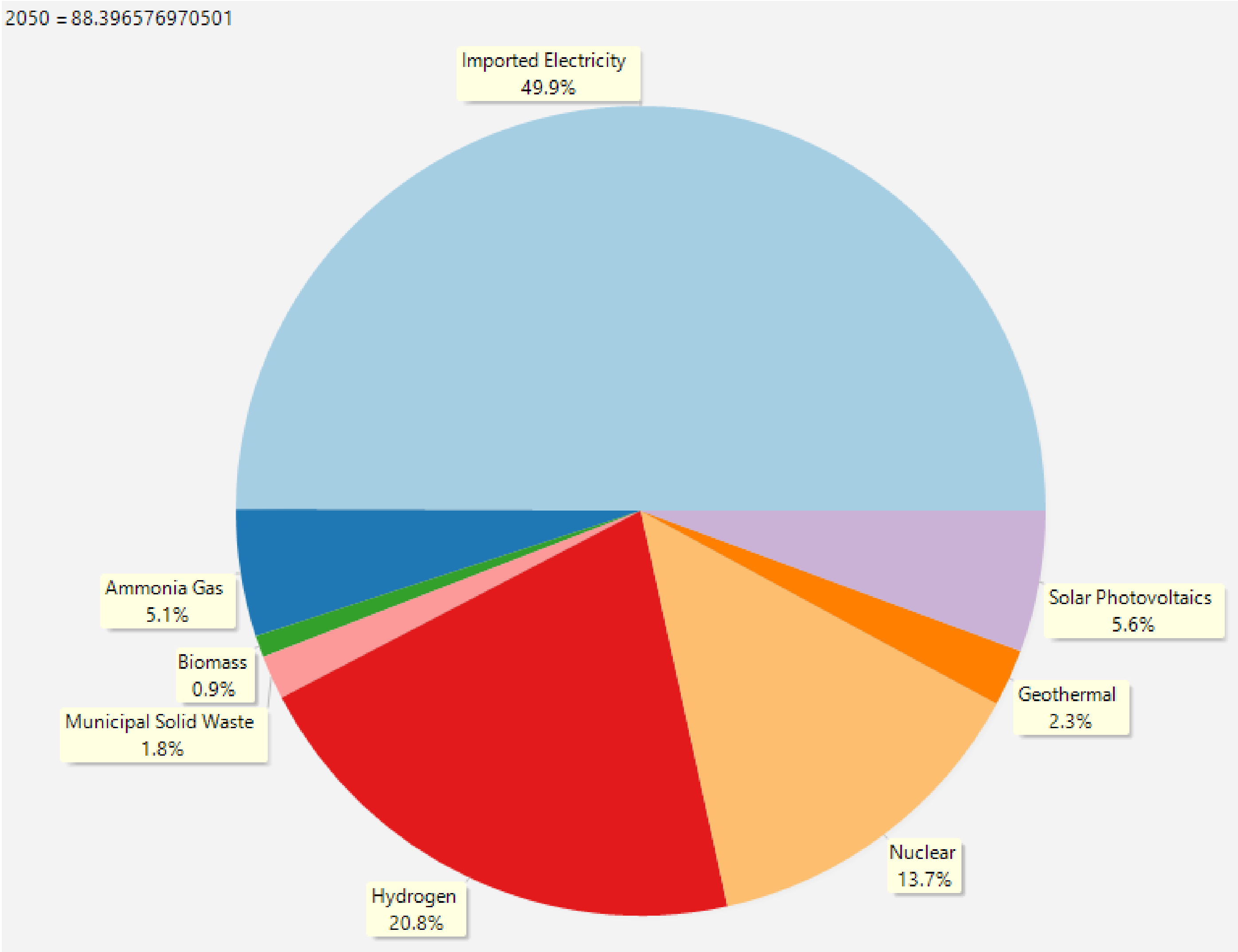


Figure 11: Percentage share of electricity generation by feedstock fuel type in 2050 (HA2)

Next, we move on to the share of electricity generation by technology. In the BAS scenario, power generation is projected to increase to 83.7 TWh in 2050. In the BAU scenario, power generation is projected to increase to 86.3 TWh by 2050. In the HA1 and HA2 scenarios, power generation is projected to increase to 89.2 TWh and 88.4 TWh respectively in 2050. These estimates are within the range of APERC (2022)'s estimate of 80 TWh in 2050 in both their BAU and Carbon-Neutral scenarios, and that of Loi (2019)'s estimates of about 90 TWh in two of their alternative policy scenarios.

In the BAU scenario, natural gas OCGTs and CCGTs also constitute the dominant share of electricity generation in 2050 but only at 64.7% compared to 93.3% in the BAS scenario. In 2050, imported renewable electricity constitutes 24.9%, oil power generators at 0.3%, WTE plants at 3.8%, coal and biomass cogeneration at 0.8%, hydrogen power generators at 3.5% and solar PV at 1.9%.

Under BAU, we would expect to see a future where Singapore's energy portfolio is still dominated by natural gas in 2050. The reserve margin remains healthy throughout the projection years, with an average annual reserve margin of 54%. The reserve margin is 39.9% in 2025, which is slightly higher than EMA's upper bound projection of 32% in the same year. From 2022-2032, due to the growth of data centres, population changes, temperature and GDP growth rates etc., EMA projects the annual system demand[99] and system peak demand to grow at a CAGR between 2.8-3.2% from 2022-2032 (EMA, 2021). In the BAU scenario, electricity generation grows at an average annual rate of 2.2% over the same period, which is slightly lower than EMA's projection.

In the HA1 scenario, the combined electricity generated by hydrogen-compatible and low-carbon ammonia power plants increases at an average annual rate of 12.9%, constituting the dominant share of electricity generation at 59.3 TWh (66.4%) in 2050. Imported renewable electricity increases at an average annual rate of 68.6%, constituting 26.1% of Singapore's projected energy supply in 2035 and reaching 21.5 TWh in 2050, constituting 24.1% share. Solar PV-generated electricity increases at an average annual rate of 8.6%, meeting around 2.5% of total electricity demand in 2030 and reaching 6.4 TWh in 2050, constituting 7.2% share.

After the two new replacement OCGT units are built in 2025, natural gas-generated electricity decreases at an average annual rate of 24.5% and is phased out in 2050. Oil-generated electricity decreases at an average annual rate of 9.7% and is phased out in 2050. WTE-generated electricity decreases at an average annual rate of 0.9%, reaching 1.4 TWh in 2050, constituting 1.5% share. Coal- and biomass-generated electricity[100] decreases at an average annual rate of 0.2%, reaching 0.7 TWh in 2050, constituting 0.7% share.

Under HA1, we would expect to see a future where Singapore's energy portfolio is dominated by low-carbon hydrogen in 2050. The reserve margin is expected to remain nearly equal to or comfortably above the planning reserve margin of 27% throughout the projection years, with an annual average of 48.5%.

In the HA2 scenario, the combined electricity generated by hydrogen-compatible and low-carbon ammonia power plants increases at an average annual rate of 23.2%, constituting 22.9 TWh (25.9%) in 2050. Imported electricity increases at an average annual rate of 73.5%, constituting 34.6% of Singapore's projected energy supply in 2035 and reaching 44.1 TWh (49.9%) in 2050. Solar PV-generated electricity increases at an average annual rate of 7.8%, meeting 2.7% of projected total electricity demand in 2030 and reaching 5 TWh (5.6%) in 2050.

After the two new replacement OCGT units are built in 2025, natural gas-generated electricity decreases at an average annual rate of 23.4% and is phased out in 2050. Oil-generated electricity decreases at an average annual rate of 9.8% and is phased out in 2050. WTE--generated electricity decreases at an average annual rate of 0.4%, reaching 1.5 TWh (1.3%) in 2050. Coal- and biomass-

[99] System demand refers to gross electricity generation required to meet electricity consumed by all consumers.
[100] Note that by 2050 in both HA1 and HA2, the coal and biomass cogeneration plants will only be using biomass as feedstock fuel.

generated electricity increases at an average annual rate of 0.3%, reaching 0.8 TWh in 2050, constituting 0.9% share. Nuclear-generated electricity increases at an average annual rate of 24.5%, reaching 12.1 TWh (13.7%) in 2050. Geothermal-generated electricity increases at an average annual rate of 24.5%, reaching 2 TWh (2.3%) in 2050.

Under HA2, we would expect to see a future where Singapore's energy portfolio is dominated by imported electricity in 2050. The reserve margin is expected to remain nearly equal to or above the planning reserve margin of 27% throughout the other projection years, with an annual average of 29.2%.

In HA1 scenario, hydrogen-compatible with low-carbon ammonia power generators, imported electricity and solar PV can supply about 69.2%, 25.1% and 7.5% of Singapore's energy needs respectively by 2050.

In the HA2 scenario, hydrogen-compatible with low-carbon ammonia power generators, imported electricity and solar PV can supply about 26.7%, 51.5% and 5.8% of Singapore's energy needs respectively by 2050. Moreover, nuclear and geothermal power generators can supply about 14.1% and 2.3% of Singapore's energy needs respectively by 2050.

The amount of electricity that needs to be generated in BAU and HA1/HA2 in 2032 (71.5 TWh and 71.8/71.7 TWh respectively) are slightly lower than EMA's projected value in that same year (74-79.5 TWh) (EMA, 2021).

## 7.3 Fuel consumption in the power sector

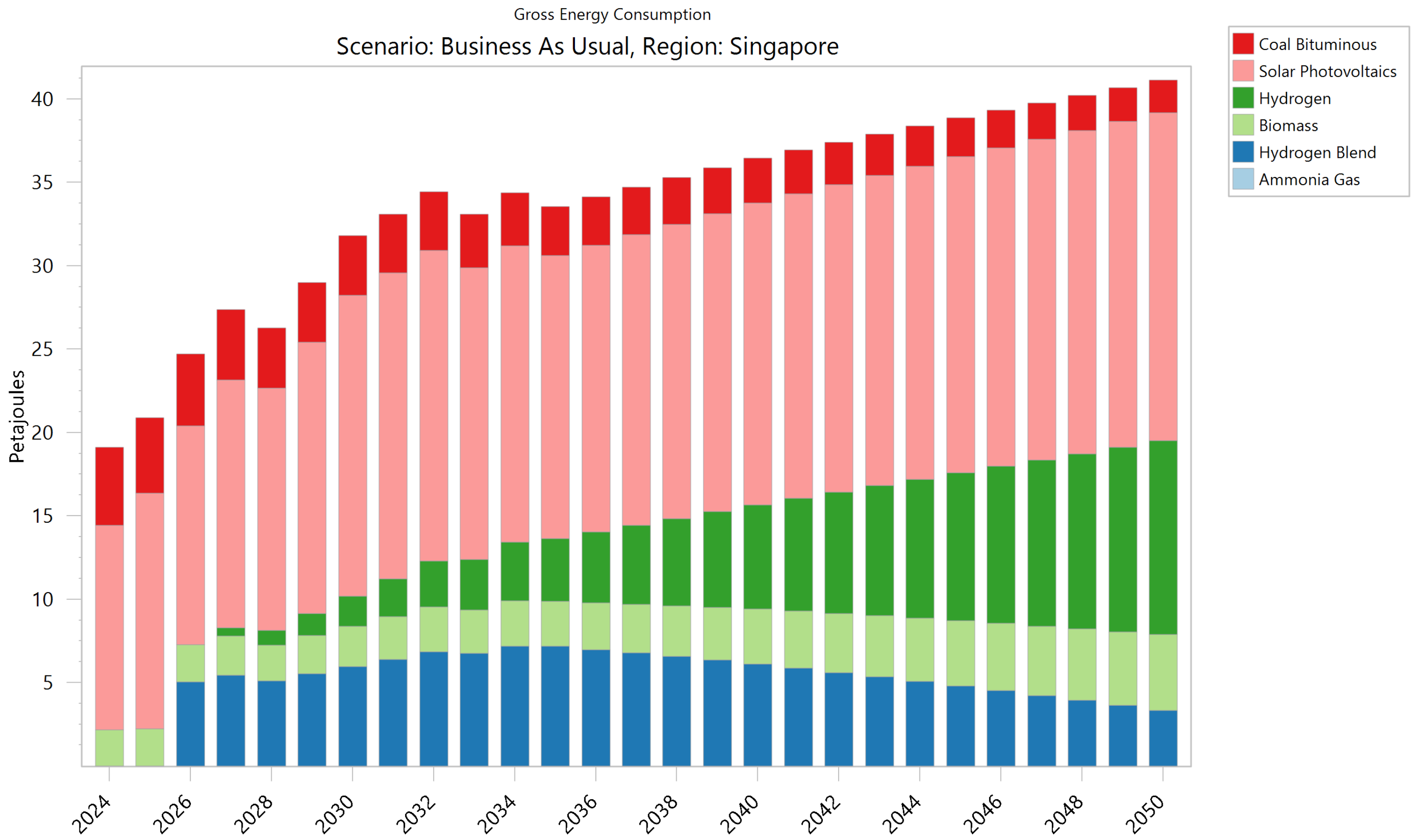


**Figure 12: Consumption of selected feedstock fuels in the power sector (BAU)**

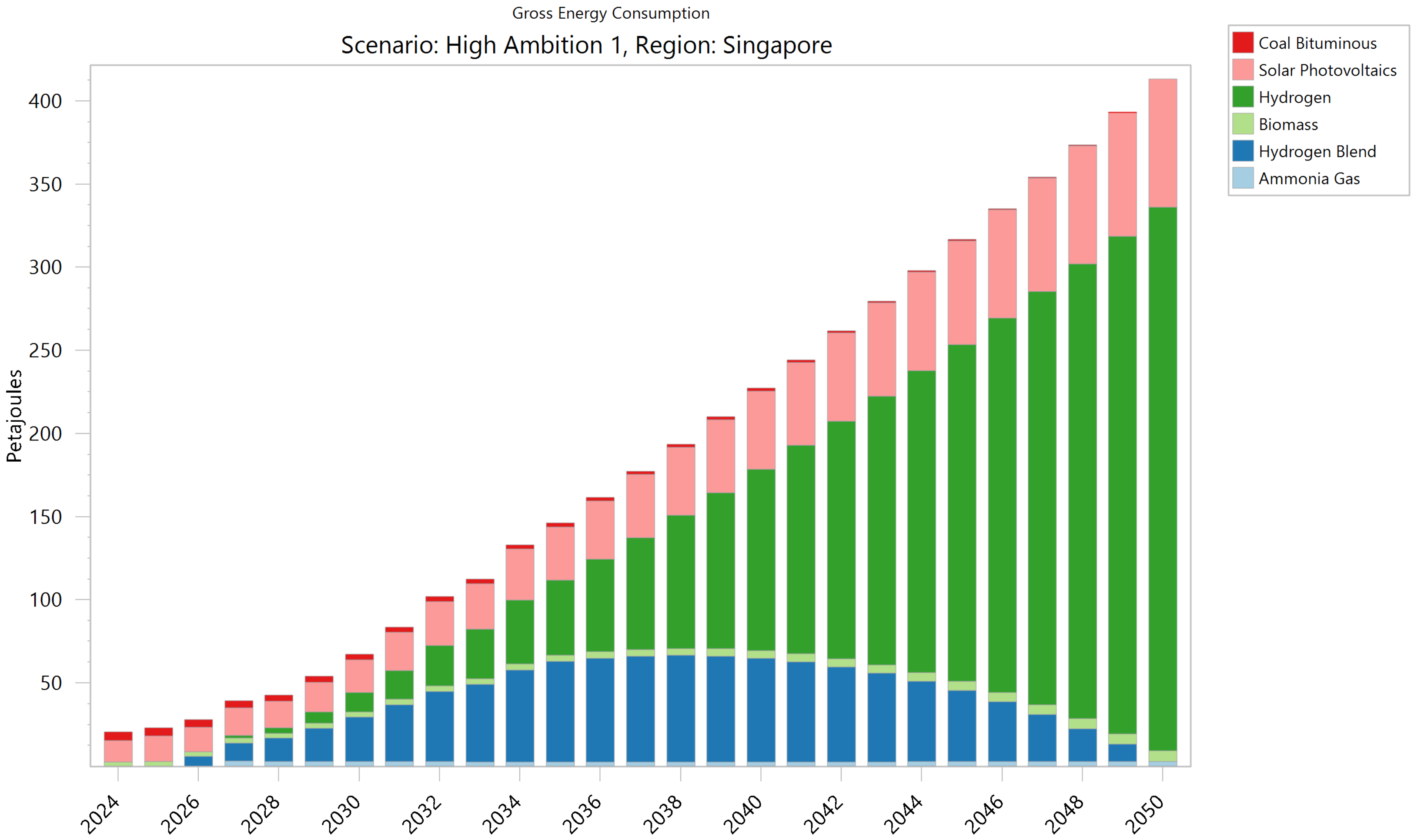


**Figure 13: Consumption of selected feedstock fuels in the power sector (HA1)**

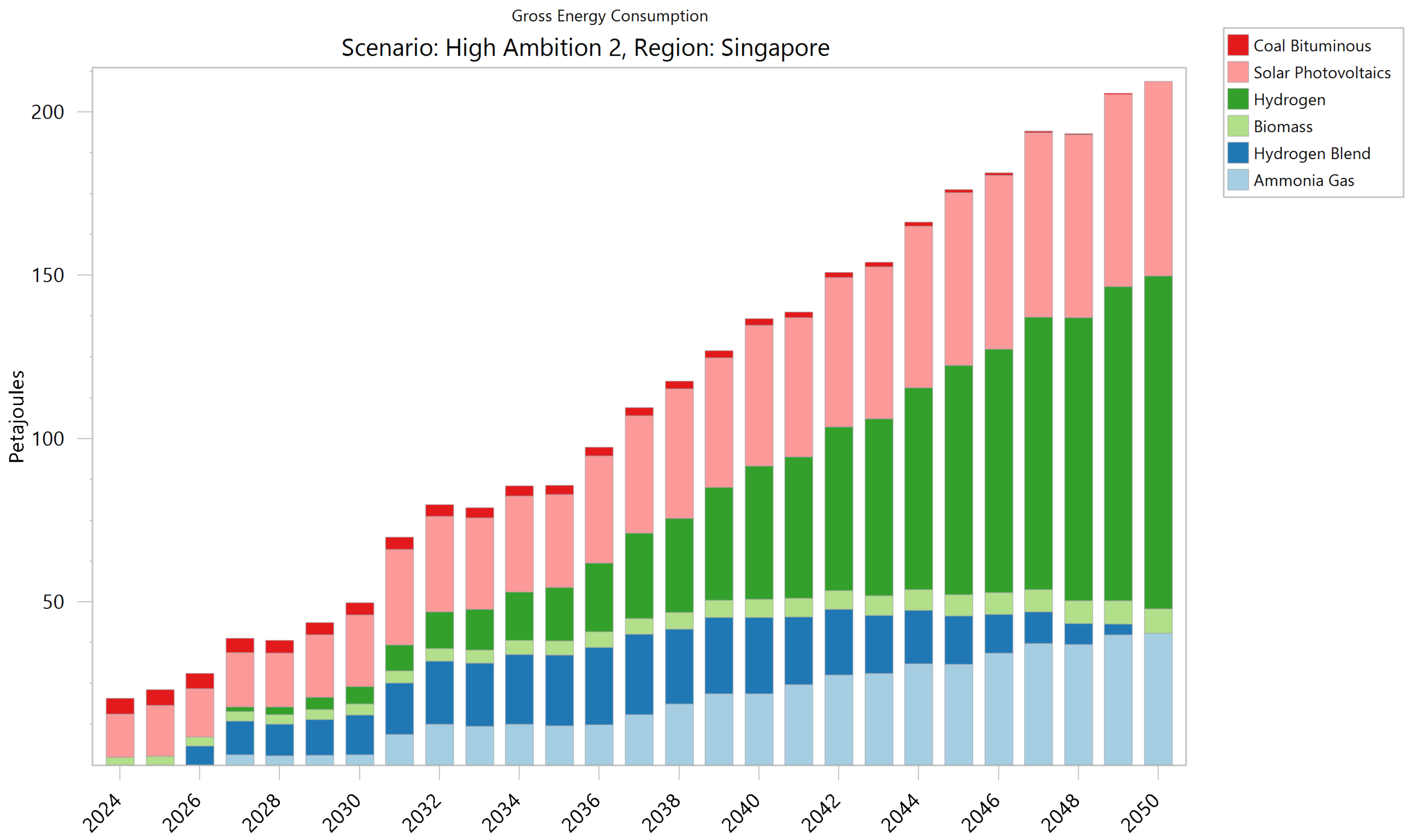


**Figure 14: Consumption of selected feedstock fuels in the power sector (HA2)**

We then analyse the consumption of hydrogen and its derivatives, as well as coal and biomass over time in the power sector. In the BAU scenario, the amount of hydrogen blend consumed initially starts out at 5 PJ in 2026, increases to a peak of 7.2 PJ in 2034 (average annual increase of 4.7%) and decreases to 3.3 PJ in 2050 (average annual decrease of 4.7%). The amount of hydrogen consumed starts out at 0.5 PJ in 2027 and increases to 11.6 PJ in 2050 (average annual increase of 15.8%).

There is a net decrease in the amount of coal consumed from 4.7 PJ in 2024 to 1.9 PJ in 2050 (average annual decrease of 3.2%). There is a net increase in the amount of biomass consumed from 2.2 PJ in 2024 to 4.5 PJ in 2050 (average annual increase of 3.1%). There is a net increase in the amount of solar PV energy consumed from 12.3 PJ to 19.7 PJ in 2050 (average annual increase of 2.7%).

In the HA1 scenario, the amount of hydrogen blend consumed initially increases from 5.7 PJ in 2026 to a peak of 64 PJ in 2038 (average annual increase of 24.2%) and then decreases over time to being phased out in 2050 (average annual decrease of 13.9%). The amount of hydrogen consumed starts out at 1.4 PJ in 2027 and increases to 326.7 PJ in 2050 (average annual increase of 29.8%). The amount of low-carbon ammonia consumed starts at 3.1 PJ in 2027, exhibits a fluctuating trend and reaches 2.7 PJ in 2050 (net average annual decrease of 0.5%).

There is a net decrease in the amount of coal consumed from 5 PJ in 2024 to being phased out in 2050 (average annual decrease of 11.4%). There is a net increase in the amount of biomass consumed from 2.4 PJ in 2024 to 6.5 PJ in 2050 (average annual increase of 4.4%). There is a net increase in the amount of solar PV energy consumed from 13.1 PJ in 2024 to 77.3 PJ in 2050 (average annual increase of 7.9%).

In the HA2 scenario, the amount of hydrogen blend consumed initially increases to a peak of 24.6 PJ in 2037 (average annual increase of 15.9%), before decreasing over time to be phased out in 2050 (average annual decrease of 14.1%). The amount of hydrogen consumed starts out at 1.3 PJ in 2027 and increases to 101.9 PJ in 2050 (average annual increase of 22.1%). The amount of low-carbon ammonia consumed starts out at 3.1 PJ in 2027, with a noticeable spike from 2030 to 2031 at 9.3 PJ before exhibiting a general increasing trend from 2036 and reaching 40.3 PJ in 2050 (net average annual increase of 15.9%).

There is a net decrease in the amount of coal consumed from 4.9 PJ in 2024 to being phased out in 2050 (average annual decrease of 10.9%). There is a net increase in the amount of biomass consumed from 2.4 PJ in 2024 to 7.5 PJ in 2050 (average annual increase of 4.9%). There is a net increase in the amount of solar PV energy consumed from 13.1 PJ in 2024 to 59.7 PJ in 2050 (average annual increase of 7.1%).

## 7.4 Share of installed generation capacity by technology

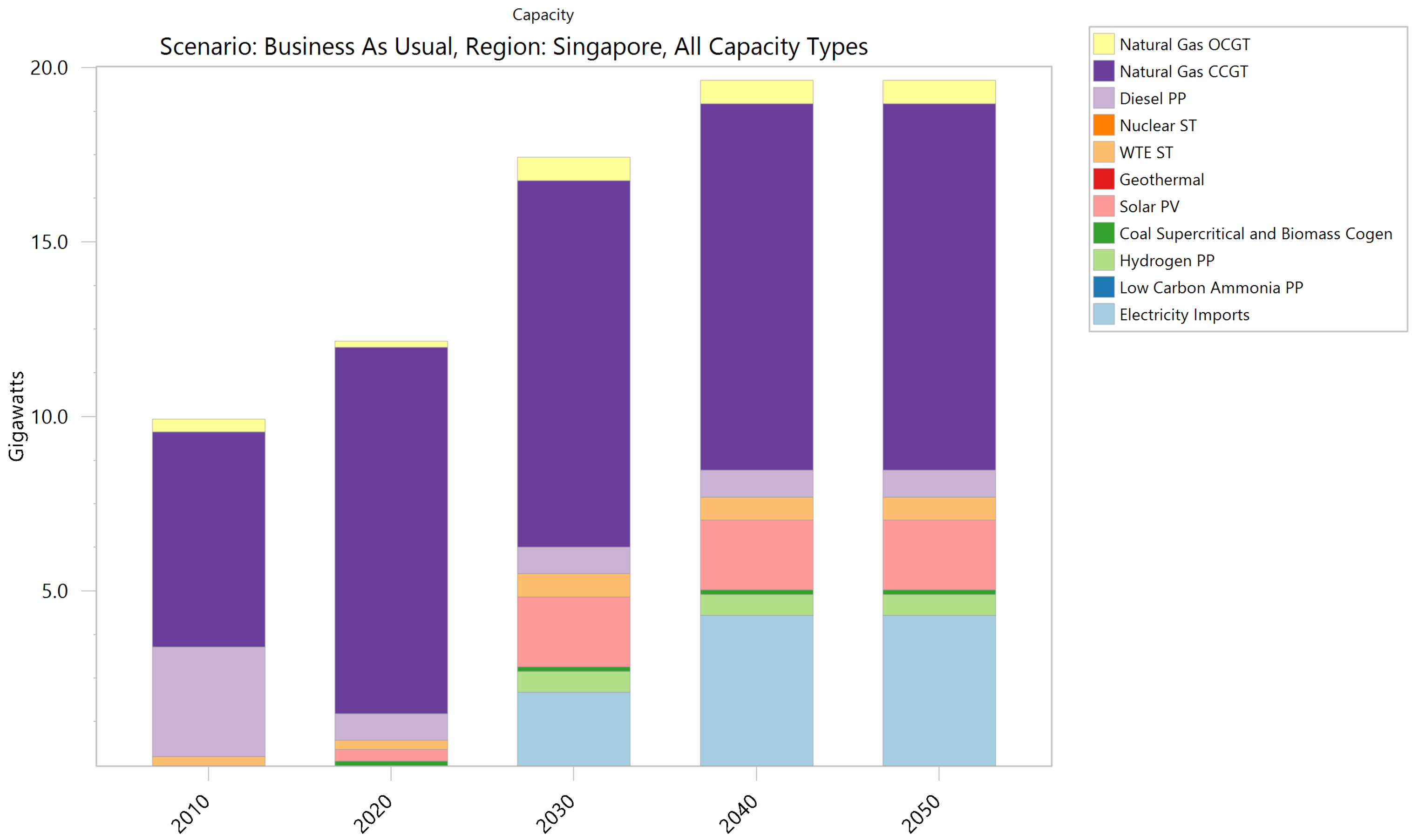


**Figure 15: Share of overall generation capacity by technology (BAU)**

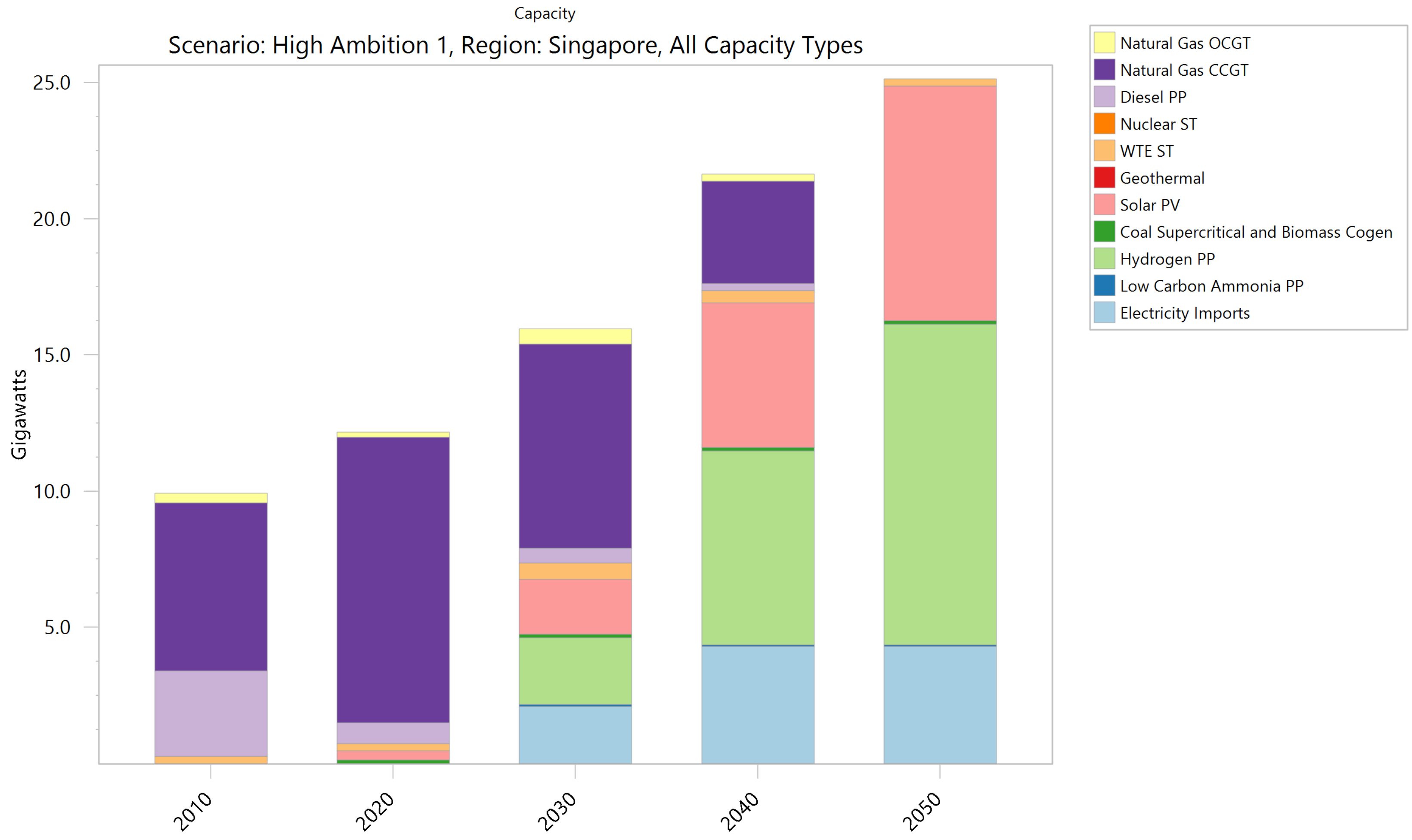


**Figure 16: Share of overall generation capacity by technology (HA1)**

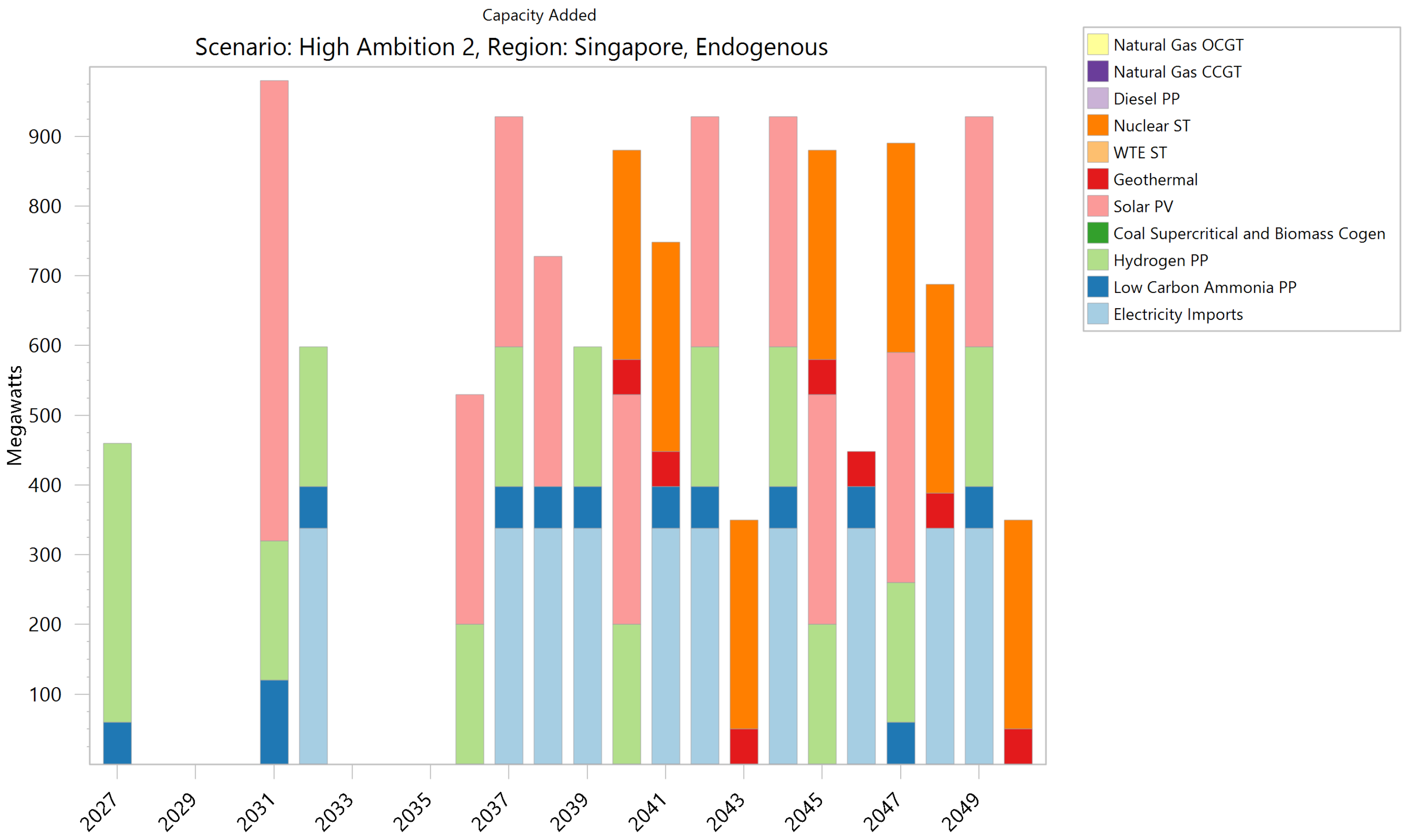


Figure 17: Share of endogenous generation capacity added by technology (HA2)

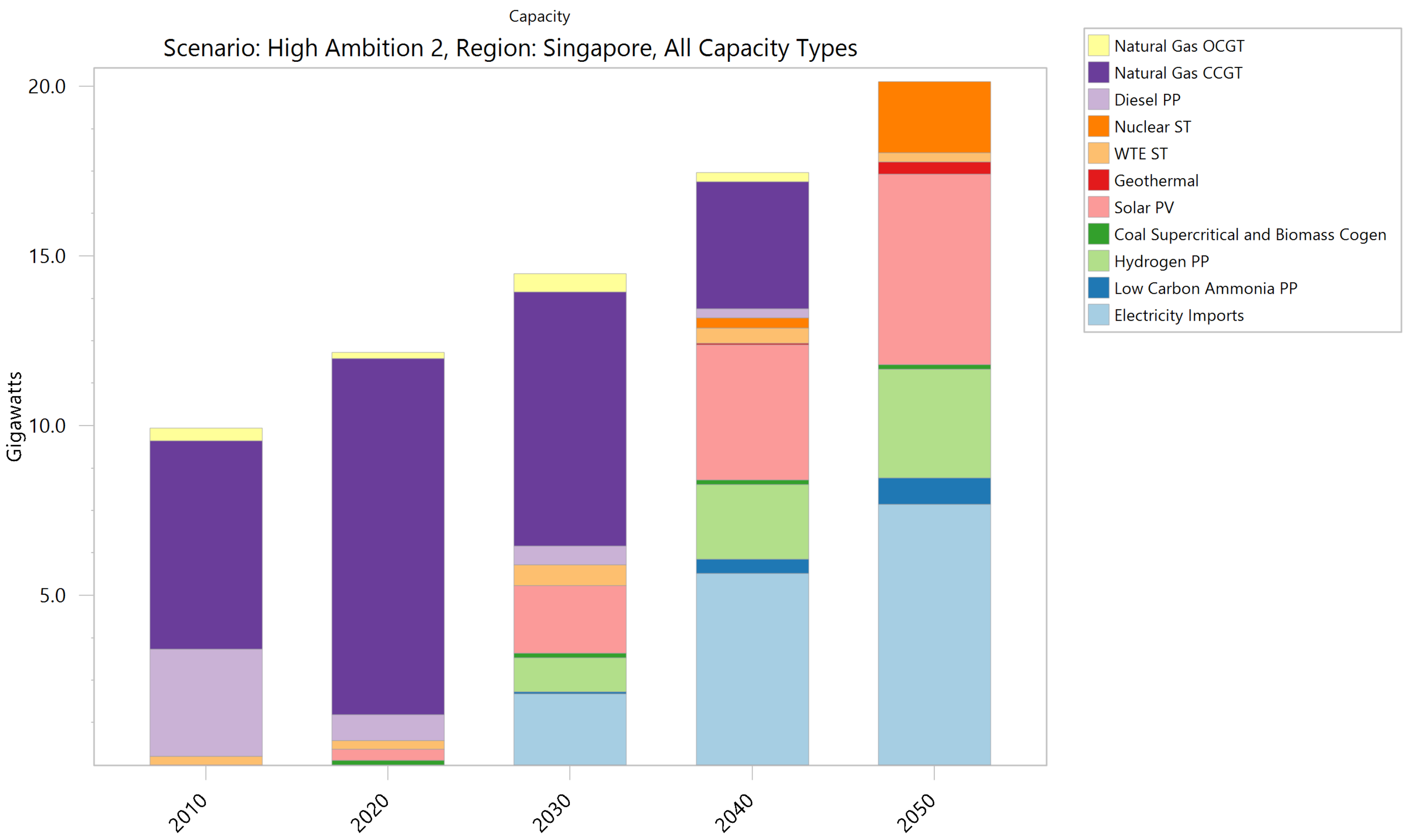


**Figure 18: Share of overall generation capacity by technology (HA2)**

We then analyse the share of overall installed generation capacity by technology. In the BAU scenario, total generation capacity increases to 19.6 GW in 2050. This is slightly higher than APERC (2022)'s estimate of 17 GW for their BAU scenario in 2050. Generation capacities of natural gas OCGT and CCGT amount to 11.2 GW, oil-fired power plants at 0.8 GW, WTE power plants at 0.7 GW, coal and biomass cogeneration power plants at 0.13 GW, solar PV at 2 GW, hydrogen power plants at 0.6 GW and imported electricity at 4.3 GW in 2050.

In the HA1 scenario, total generation capacity increases to 25.1 GW in 2050. This is higher than APERC (2022)'s estimate of 21 GW total generation capacity in 2050. The top 3 generation capacities are hydrogen power plants at 11.8 GW, solar PV at 8.6 GW and imported electricity at 4.3 GW. No endogenous capacity needs to be added, implying that the amount of specified exogenous capacity alone is sufficient to maintain the planning reserve margin of 27% in all projected years from 2027.

In the HA2 scenario, total generation capacity increases to 20.1 GW in 2050. The top 3 generation capacities are imported electricity at 7.7 GW, solar PV at 5.6 GW and hydrogen power plants at 3.2 GW.

In HA2, 300 MW of nuclear generation capacity needs to be endogenously added in 2040-2041, 2043, 2045, 2047-2048 and 2050.

50 MW of geothermal generation capacity needs to be endogenously added in 2040-2041, 2043, 2045-2046, 2048 and 2050.

660 MW of solar PV capacity needs to be endogenously added in 2031, followed by 330 MW in 2036-2038, 2040, 2042, 2044-2045, 2047 and 2049.

400 MW of hydrogen generation capacity needs to be endogenously added in 2027, followed by 200 MW in 2031-2032, 2036-2037, 2039-2040, 2042, 2044-2045, 2047 and 2049.

60 MW of low-carbon ammonia generation capacity needs to be endogenously added in 2027, followed by 120 MW in 2031, 60 MW in 2032, 2037-2039, 2041-2042, 2044, 2046-2047 and 2049.

338 MW of electricity imports needs to be endogenously added in 2032, 2037-2039, 330 MW in 2041-2042, 2044, 2046 and 2048-2049.

In terms of the cumulative amount of endogenous capacity added: 2.1 GW of nuclear, 350 MW of geothermal, 3.6 GW of solar PV[101], 2.6 GW of hydrogen and 780 MW of low-carbon ammonia power generation capacity as well as 3.4 GW of electricity imports would have been endogenously added by 2050.

Total generation capacity in 2025 is 13.8 GW and 12.6 GW in BAU and HA1/HA2 respectively, which are higher than the projected generation capacity by EMA in 2025 (11.6 GW) (EMA, 2021)

[101] As noted in section 7.4, the sum of the cumulative amount of exogenous solar PV generation capacity added by 2030 (BAU) and endogenous capacity added from 2031-2050 (HA2) is at 5.6 GW, which is still lower than Singapore's maximum technical potential for solar PV deployment of 8.6 GW.

## 7.5 Absolute emissions in power sector by technology (100-Year GWP)

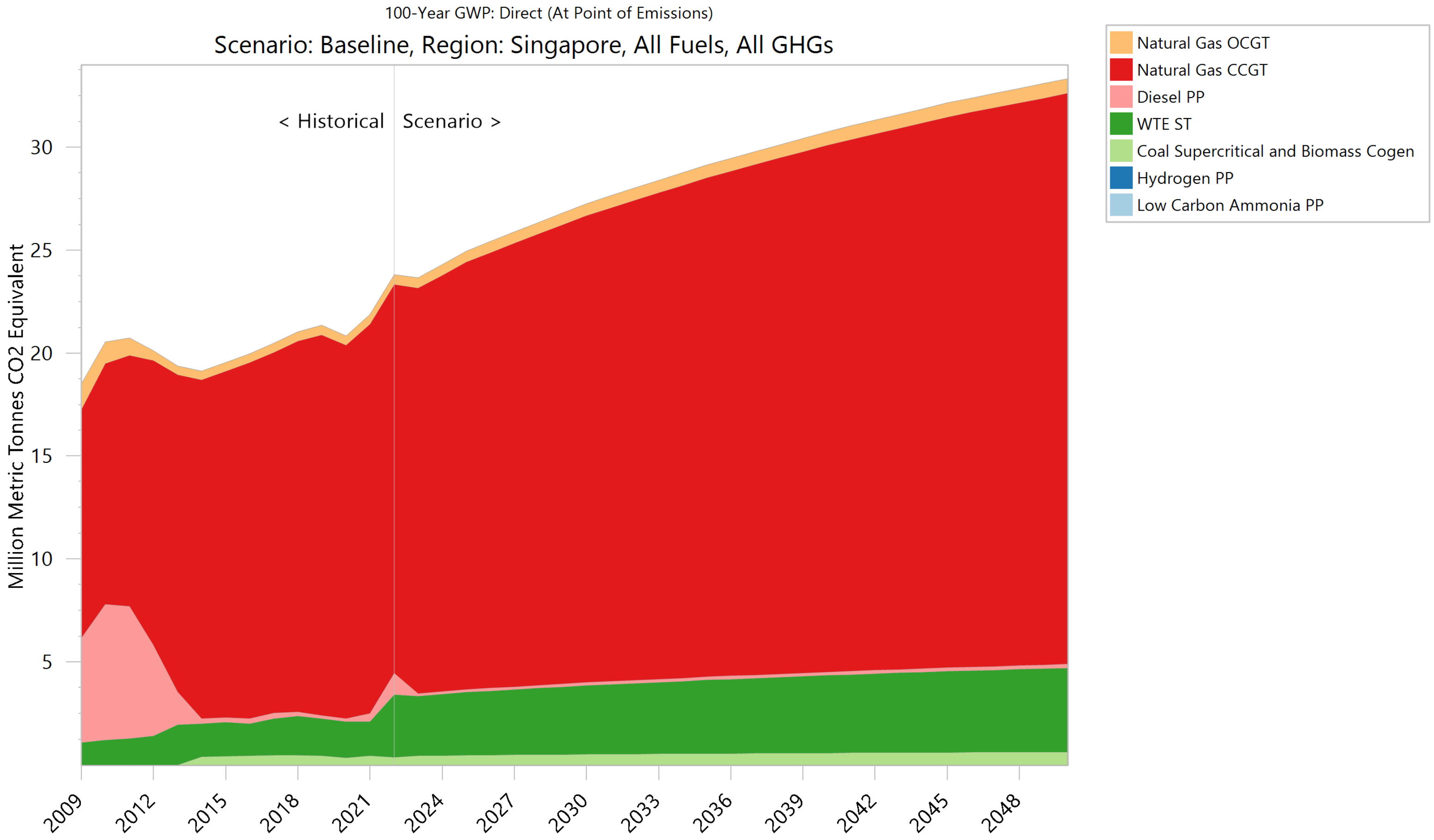


**Figure 19: Absolute emissions in power sector by technology (100-Year GWP) (BAS)**

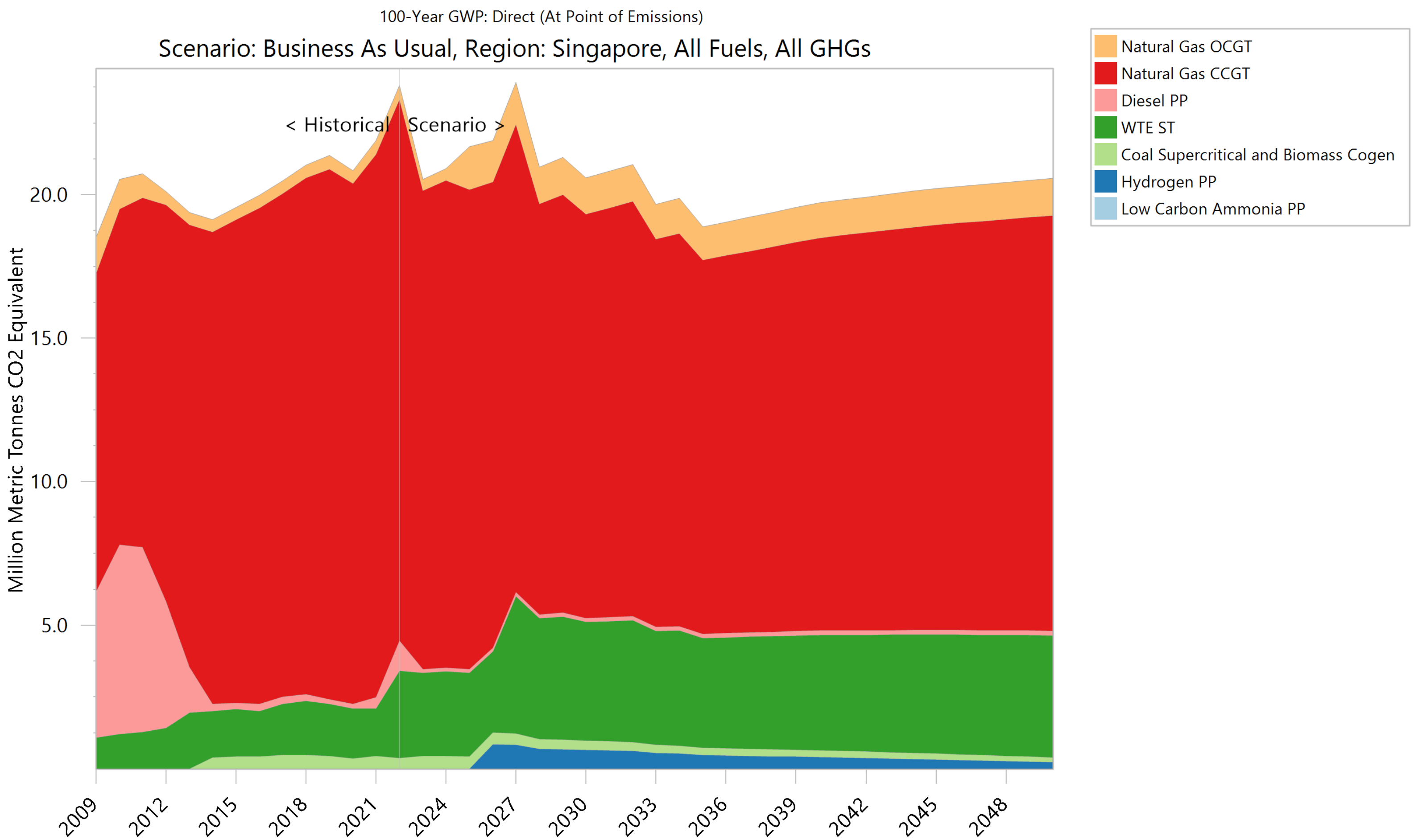


Figure 20: Absolute emissions in power sector by technology (100-Year GWP) (BAU)

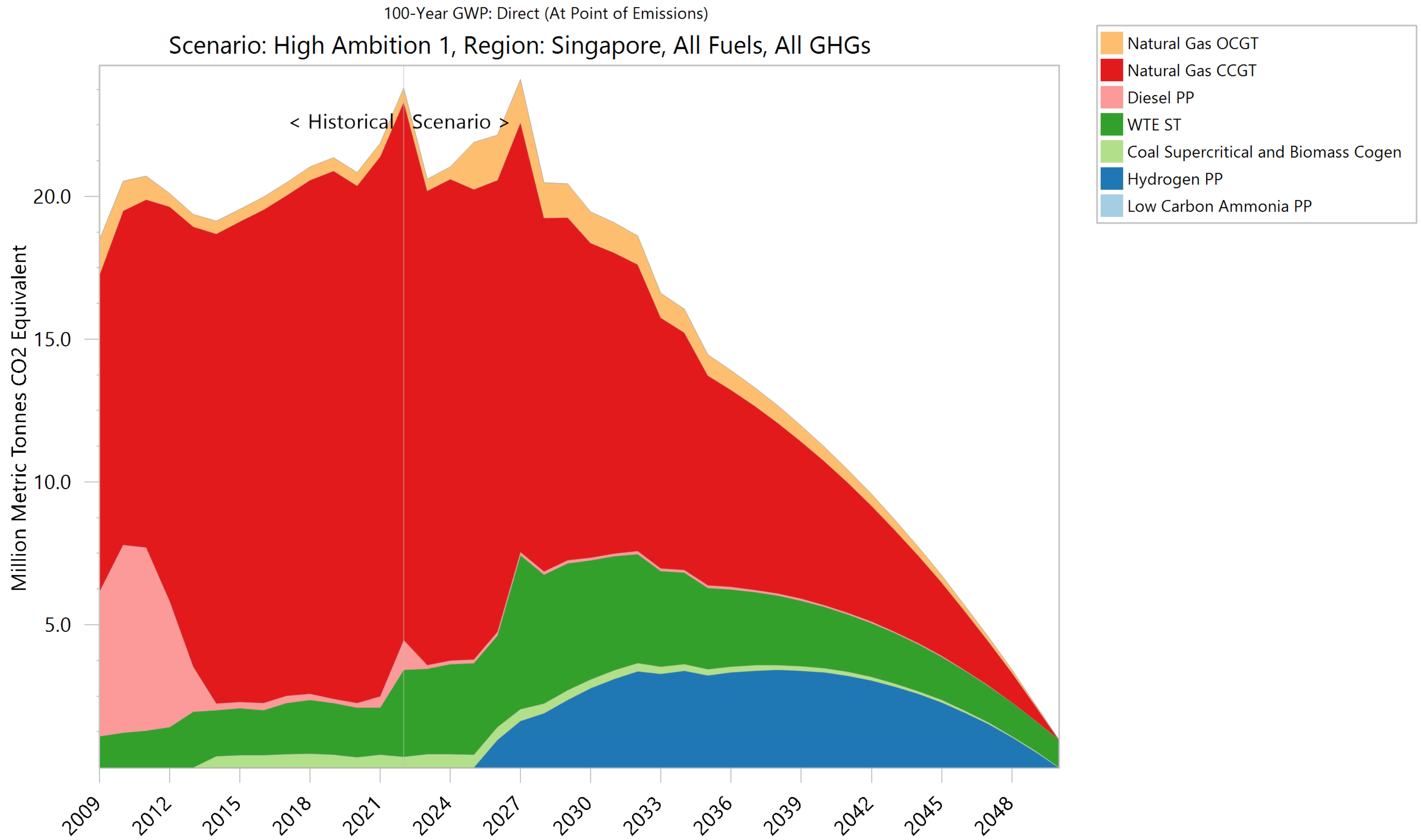


**Figure 21: Absolute emissions in power sector by technology (100-Year GWP) (HA1)**

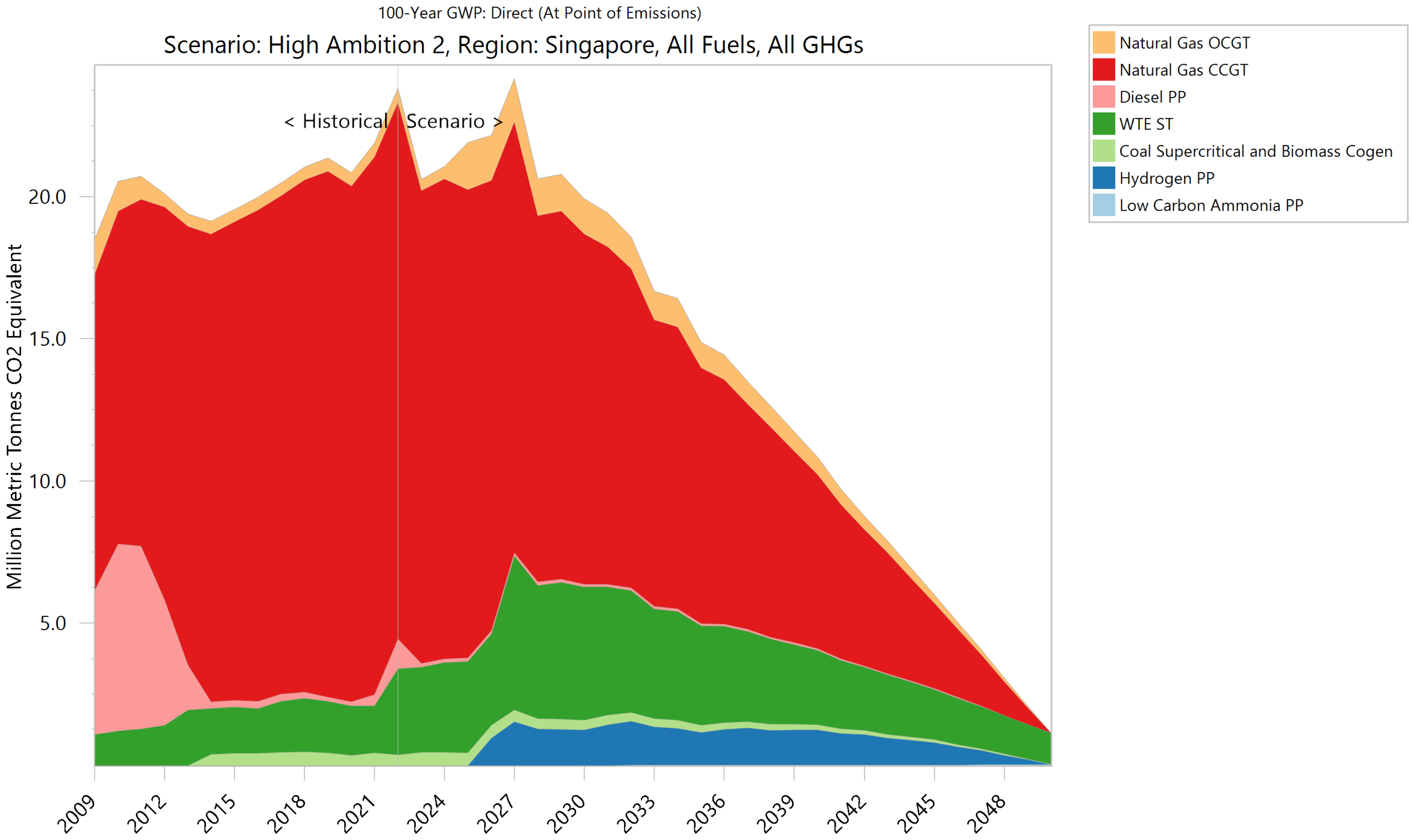


**Figure 22: Absolute emissions in power sector by technology (100-Year GWP) (HA2)**

Assessing the absolute emissions in terms of GHG warming potential over a 100-year period in the power sector is a critical highlight of this exercise. In the BAU scenario, GHG emissions from the power sector, despite a series of fluctuations during the projected years, are not expected to change much from 2023-2050, remaining at around 20.6 $MtCO_2e$ in both the start projection year and the end projection year. There is 6.7 $MtCO_2e$ and 12.8 $MtCO_2e$ more carbon abatement potential than the BAS scenario in 2030 and 2050 respectively. Natural gas OCGTs and CCGTs contribute predominantly to emissions in 2030 (74.5%) and in 2050 (76.7%).

In the HA1 and HA2 scenarios, GHG emissions from the power sector are projected to peak at 24.1 $MtCO_2e$ in 2027, and generally decreasing to around 0.98 and 1.15 $MtCO_2e$ in 2050 respectively. Emissions start decreasing consistently after 2027 in HA1 and after 2029 in HA2.

Emissions are slightly higher from 2023-2027 in HA1 and HA2 by 0.1-0.3 $MtCO_2e$ compared to BAU due to more electricity produced by natural gas OCGTs, WTE plants, coal and biomass cogeneration plants as well as hydrogen[102] and low-carbon ammonia power plants. However, as hydrogen-compatible technologies become more mature with the phasing out of all fossil fuels in the energy mix, there would be a significantly lower amount of emissions generated relative to BAU.

On average, HA1 has generally higher annual emissions of 0.1 $MtCO_2e$ than HA2 between 2027-2050. During the same period, the rate of average annual decrease in emissions in HA1 is 11.9% compared to 11.7% in HA2. In 2050, the remaining emissions in HA1 and HA2 come from the combustion of MSW, low-carbon ammonia and biomass, with WTE plants generating the majority of emissions (0.96 $MtCO_2e$ and 1.10 $MtCO_2e$ respectively)[103].

Between 2027-2050, HA2 can abate a net cumulative total of 3.1 $MtCO_2e$ more emissions compared to HA1. HA2's higher overall emissions abatement potential relative to HA1 is attributed to the lower level of cumulative emissions generated from oil-fired power plants and hydrogen power plants by 35.9 $MtCO_2e$. This offsets the higher level of cumulative emissions (32.8 $MtCO_2e$) generated from the other power plants in HA2 (natural gas OCGTs and CCGTs, WTE, coal with biomass cogeneration and low-carbon ammonia power plants) during that period compared to the same power plants in HA1.

The noticeable discontinuities before and after 2036 can be explained by the modelling parameters and assumptions whereby before 2036, there are some officially planned (exogenous) capacity additions of certain processes in certain years which may see a large jump in existing capacity in a particular year such as the construction of the new natural gas OCGT units, hydrogen power plant and energy import infrastructure. Moreover, as the merit order of dispatch is assigned equally to all power generation processes, some fluctuations in the emissions of certain power generation processes are expected as the proportions of the electricity generated by those processes to overall capacity change over the years. As the last planned capacity addition occurs in 2035 (electricity imports from Cambodia based on our assumption), the capacities are stabilised after that and thus we will expect to see a consistent trend in the rate of emissions growth until 2050.

[102] Note that the upcoming hydrogen power plant will still be relying mostly on natural gas and hydrogen blend as fuels in 2030.
[103] Tangri (2023) found that in the U.S., contrary to the defense of WTE plants as a source of cleaner energy relative to fossil fuels, the amount of GHG emissions per unit of electricity produced from MSW incineration is 1707 $gCO_2e/kWh$. When Tangri (2023)'s environmental loading factor for MSW incineration was used in our model instead, we found that it results in a generation of 1.15-1.32 $MtCO_2e$ of emissions in 2050, which does not differ significantly from our result.

## 7.6 Grid emission factor

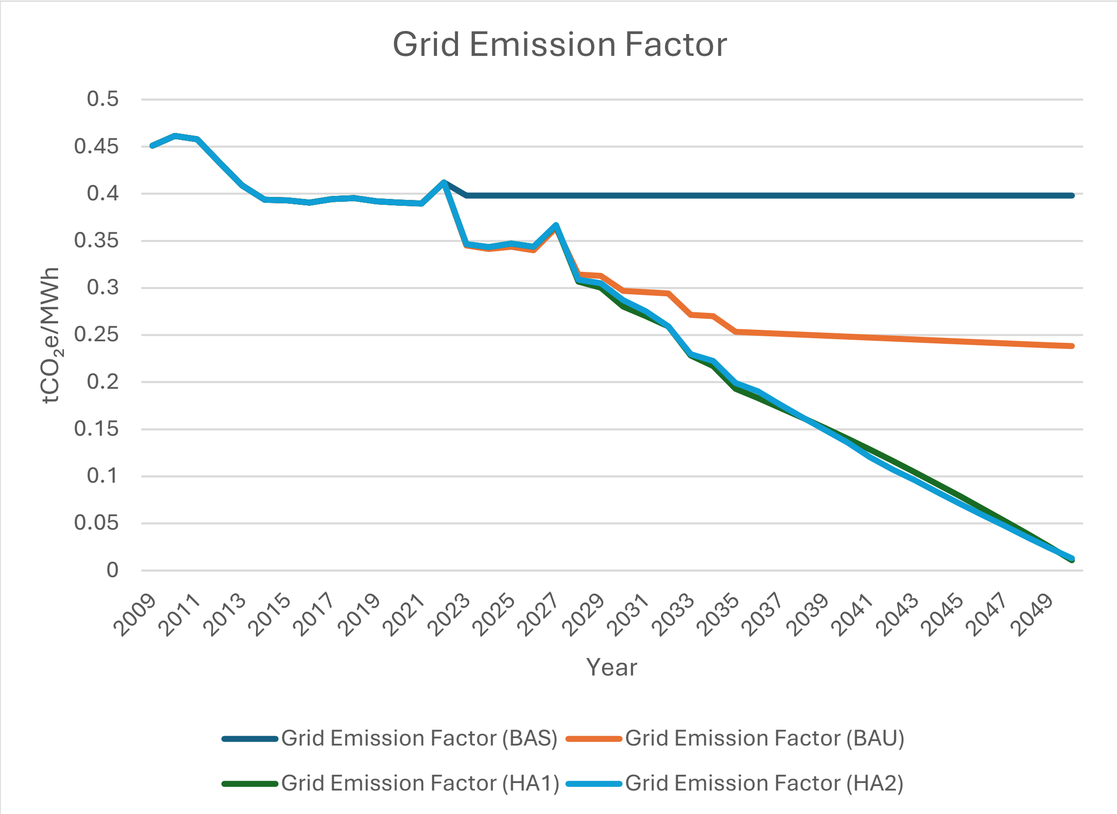


**Figure 23: Grid emission factor (BAS, BAU, HA1 and HA2)**

Grid emission factor measures the amount of carbon emissions per unit of electricity generated. Historical data inputs on electricity generation and its corresponding emissions result in a grid emission factor of 0.412 $tCO_2e/MWh$ in 2022, which is slightly lower than EMA's estimate of 0.417 $tCO_2e/MWh$ in the same year. In the BAS scenario, grid emission factor is projected to hover around 0.398 $tCO_2e/MWh$ in the projected period. From 2009-2050, grid emission factor would have been reduced by 11.7%.

In the BAU scenario, however, grid emission factor is projected to reduce from 0.345 $tCO_2e/MWh$ in 2023 (incidentally surpassing EMA's new emission standard of 0.355 $tCO_2e/MWh$ for generation units), to 0.297 $tCO_2e/MWh$ in 2030 and to 0.238 $tCO_2e/MWh$ in 2050. From 2009-2050, grid emission factor would have been reduced by 44.7%.

In the HA1 and HA2 scenarios, grid emission factor is projected to reduce to about 0.280 $tCO_2e/MWh$ in 2030 and to 0.0109 $tCO_2e/MWh$ and 0.0130 $tCO_2e/MWh$ in 2050 respectively. Grid emission factor is lower in HA1 compared to HA2 during 2027-2031, 2033-2038 and in 2050, while grid emission factor is higher in HA1 compared to HA2 in 2032 and during 2039-2049.

## 7.7 Absolute emissions from all domestic sectors (100-Year GWP)

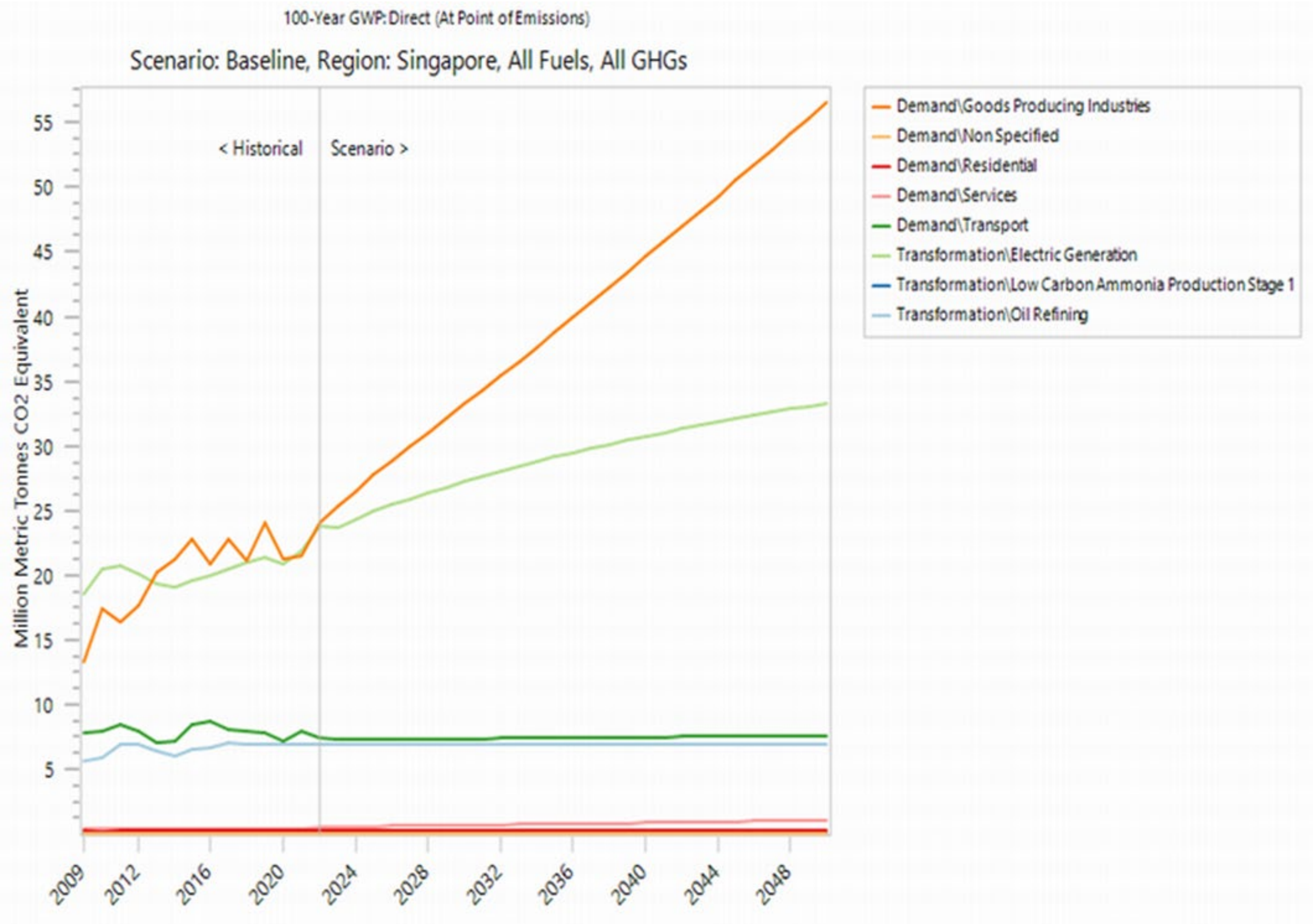


Figure 24: Absolute emissions by domestic energy demand/supply sector (100-Year GWP) (BAS)

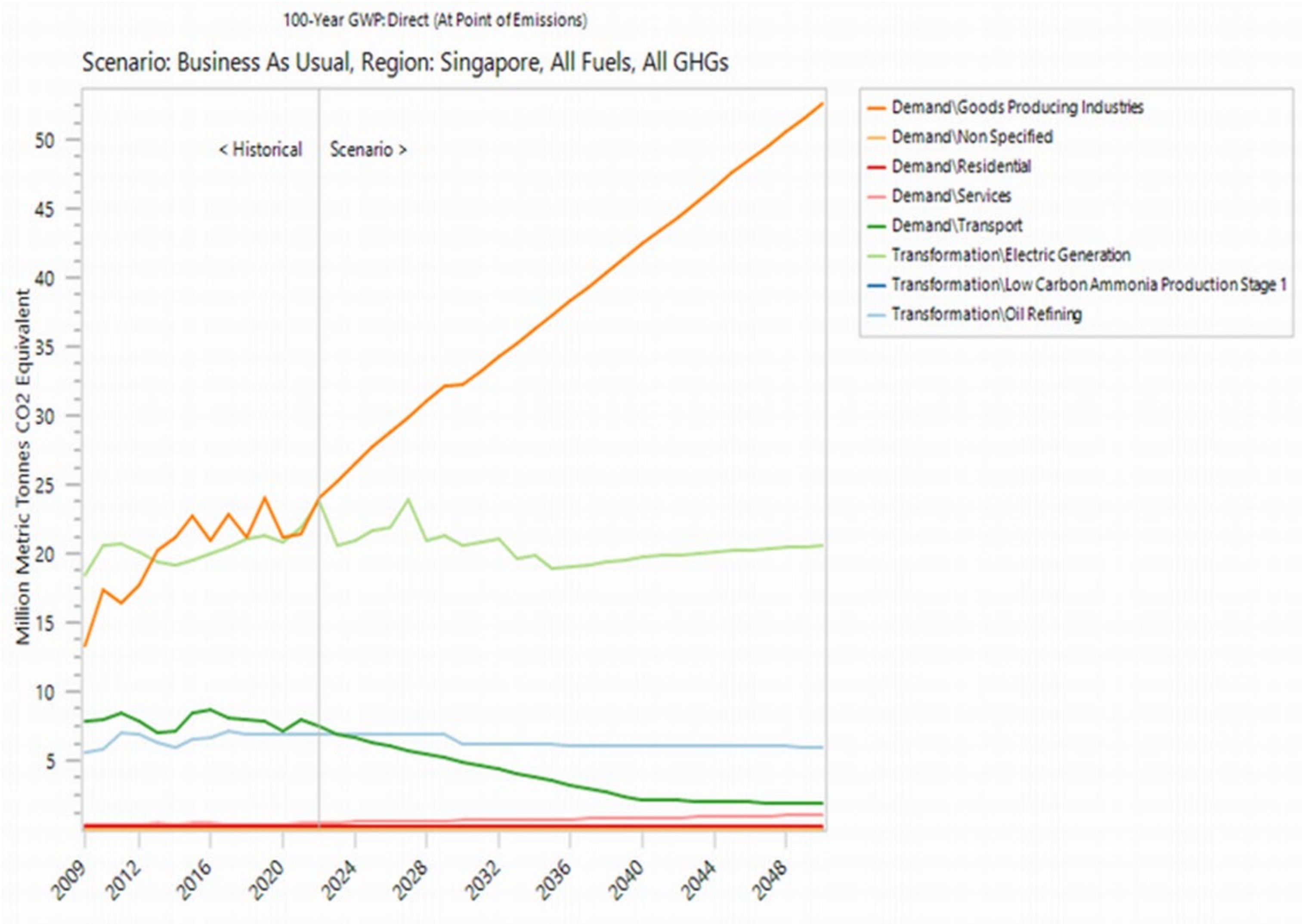


Figure 25: Absolute emissions by domestic energy demand/supply sector (100-Year GWP) (BAU)

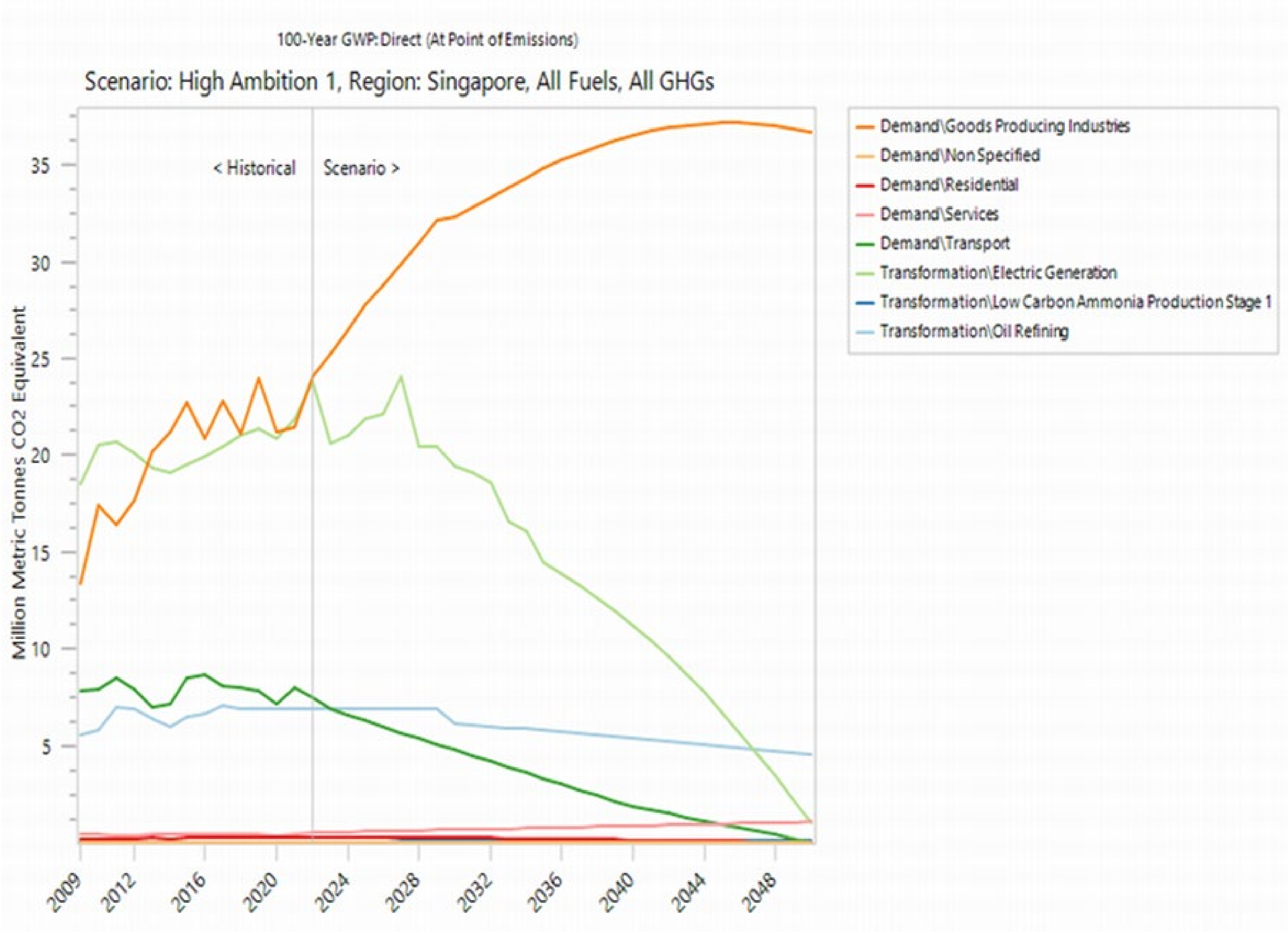


Figure 26: Absolute emissions by domestic energy demand/supply sector (100-Year GWP) (HA1)

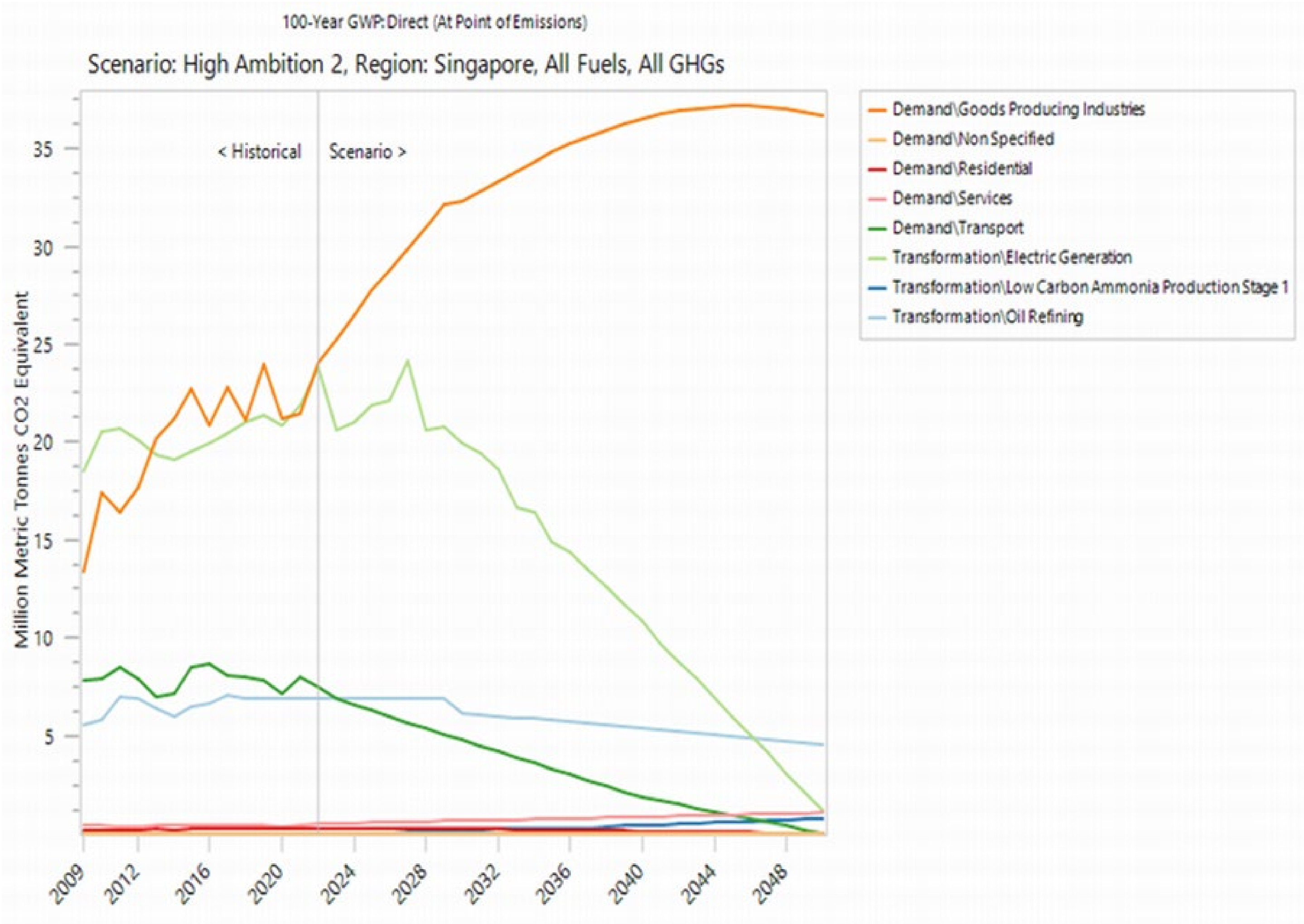


Figure 27: Absolute emissions by domestic energy demand/supply sector (100-Year GWP) (HA2)

Next, we turn to absolute emissions from all domestic sectors. Based on the national GHG inventory[104], Singapore's GHG emissions are at 53.7 $MtCO_2e$ in 2021. Our BAS estimates accounting for historical GHG emissions from all domestic sectors are higher at 58.9 $MtCO_2e$ in 2021.

In the BAU scenario, there is a net average annual increase in GHG emissions from all domestic sectors from 60.3 $MtCO_2e$ to 82.4 $MtCO_2e$ between 2023-2050, with the industrial sector constituting the majority (63.9%) of overall emissions. This falls between APERC (2022)'s estimate of 50 $MtCO_2e$ and Doshi and D'Souza (2013)'s estimate of 95.6 $MtCO_2e$ by 2050 in their BAU-equivalent scenarios. This is 10.8 $MtCO_2e$ and 23.3 $MtCO_2e$ less emissions than the BAS scenario in 2030 and 2050 respectively.

At 64.9 $MtCO_2e$ of emissions in 2030 and continuing to show a general increase (1.2%) for the remainder of the projection period, this suggests that BAU does not meet the first part of the latest revised NDC target of 60 $MtCO_2e$ by 2030. However, it partially meets the first part of the previously enhanced NDC target of 65 $MtCO_2e$ by 2030 by reaching that emissions level but failing to meet the second condition of peaking emissions at 65 $MtCO_2e$ within that timeframe.

In the HA1 scenario, GHG emissions from all domestic sectors are projected to increase to a peak of 67.5 $MtCO_2e$ in 2027, reaching 63.7 $MtCO_2e$ in 2030 and continue to generally decrease to 43.4 $MtCO_2e$ in 2050, with goods producing industries constituting the majority (84.6%) of overall emissions. The HA2 scenario peaks emissions in 2027 at 67.5 $MtCO_2e$, reaching 64.1 $MtCO_2e$ in 2030 and continue to generally decrease to 44.2 $MtCO_2e$ in 2050, with goods producing industries constituting the majority (83%) of overall emissions.

This suggests that HA1 and HA2 fare better than BAU in meeting the first part of the previously enhanced NDC target of 65 $MtCO_2e$ by 2030. Emissions can also be peaked before 2030. HA1 and HA2 are also closer to meeting the second part of the previously enhanced NDC target (33 $MtCO_2e$ by 2050) compared to BAU.

Our 2050 estimates in all scenarios are higher than that of APERC (2022) and Loi (2019) (16 $MtCO_2e$ and less than 14 $MtCO_2e$ in 2050 respectively) with overall fewer highly ambitious demand sector energy efficiency/carbon abatement measures in our model.

[104] https://www.nea.gov.sg/our-services/climate-change-energy-efficiency/climate-change/greenhouse-gas-inventory

## 7.8 Emission intensity

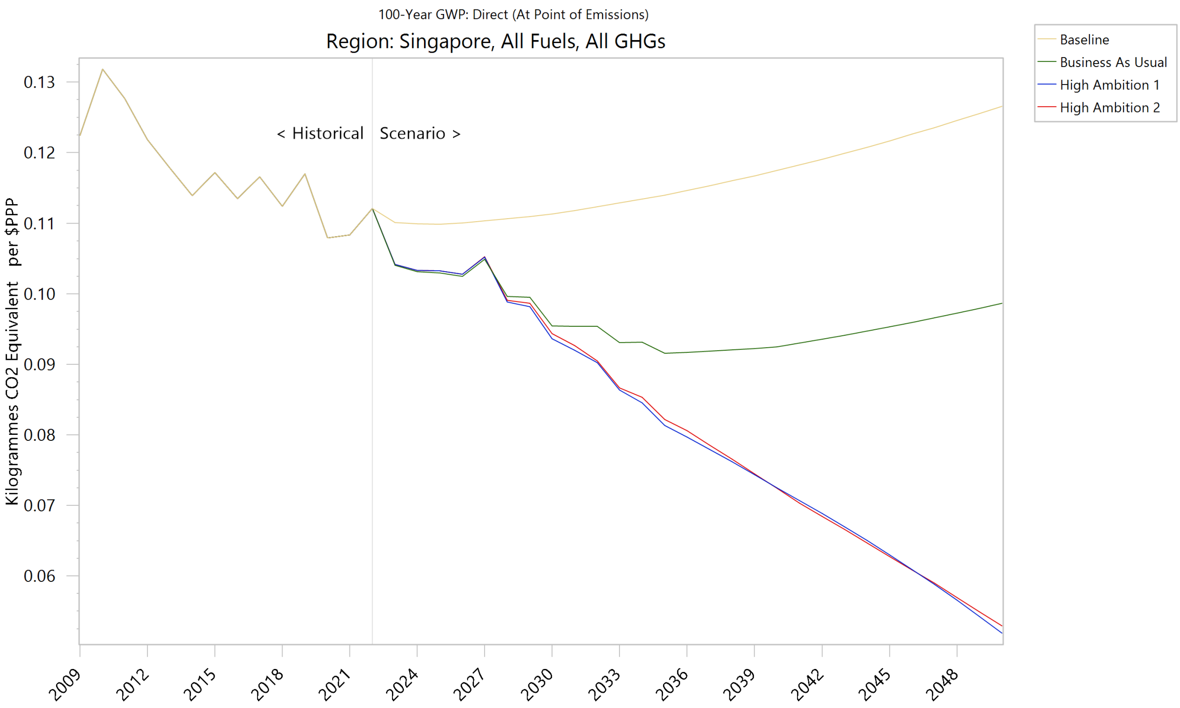


**Figure 28: Emission intensity (BAS, BAU, HA1 and HA2)**

Emission intensity is the volume of emissions per unit of GDP. In the BAS scenario, under SSP2, emission intensity of all domestic sectors is expected to increase from 0.110 $kgCO_2e$/\$PPP (at 2007 prices) in 2023 to 0.111 $kgCO_2e$/\$PPP in 2030 and to 0.123 $kgCO_2e$/\$PPP in 2050. In the BAU scenario, emission intensity is expected to generally decrease from 0.104 $kgCO_2e$/\$PPP in 2023 to 0.0954 $kgCO_2e$/\$PPP in 2030, but increasing to 0.0986 $kgCO_2e$/\$PPP in 2050.

In the HA1 scenario, emission intensity is expected to peak at 0.105 $kgCO_2e$/\$PPP in 2027 and reduce to 0.0937 $kgCO_2e$/\$PPP in 2030 and to 0.0519 $kgCO_2e$/\$PPP in 2050. In the HA2 scenario, emission intensity is expected to reduce to 0.0943 $kgCO_2e$/\$PPP in 2030 and to 0.0529 $kgCO_2e$/\$PPP in 2050.

Although BAU can achieve the government's initial 2030 emissions intensity target of 0.113 $kgCO_2e$/S\$GDP at 2010 prices (converted to 0.0976 $kgCO_2e$/\$PPP at 2007 prices[105]) by 2030, it cannot sustain this target by 2049. However, HA1 and HA2 can achieve this target and maintain it by 2030.

It is also interesting to note that there is a year-on-year increase in absolute emissions but a year-on-year decrease in emission intensity between 2023-2026, 2028-2029 and 2030-2032 in BAU, and between 2023-2026 and 2028-2029 in both HA1 and HA2. An increase in absolute emissions (the numerator) with a larger increase in GDP (the denominator) relative to emissions would still result in a decrease in emission intensity, but not absolute emissions. However, the trade-off is that while setting an emissions target independent of GDP is more effective at reducing absolute emissions, it could have an adverse effect on economic competitiveness.

[105] https://data.oecd.org/conversion/purchasing-power-parities-ppp.htm

# 8. SCENARIOS MODELLED (OPTIMISATION)

The Next Energy Modelling system for Optimisation (NEMO), an open-source energy system optimisation tool developed by the Stockholm Environment Institute (SEI), creates a database of results from LEAP model inputs and defines the systems of equations that describe the optimisation problem and then sends them to the solver. The solver starts with multiple iterations in an attempt to find the optimal solution and sends it back to the database of results, which is then packaged by NEMO and sent back to LEAP. In this exercise, we focus on two optimisation scenarios, using “Cbc” as the optimisation solver.

In LEAP’s standard simulation calculations, we specified to LEAP what types of power plants to add under endogenous capacity, although LEAP will decide when to add them. Using LEAP’s optimisation calculations, however, LEAP will decide what processes to add and when to add them with the objective of minimising electricity generation (technology and fuel) costs as well as other cost and performance constraints defined by the user such as producing enough electricity to meet demand, or limiting capacity and emissions.

Constraints on optimisation are typically used to align projections with historical data and trends, set upper/lower bounds on capacity (e.g., to add new planned capacity in the future, or to limit very inexpensive technologies) and activity (e.g., limit to renewable resources), set a limit to annual emissions for any given pollutant, comply with a minimum renewable portfolio standard and so on.

The optimisation scenarios modelled are represented as HA1 (Optimised) and HA2 (Optimised). Both HA1 (Optimised)[106] and HA2 (Optimised) inherit the historical data inputs and policy assumptions pertaining to energy efficiency and cleaner energy in the near future from the HA2 scenario in our simulation exercise. However, we now we also allow for energy storage modelling and endogenous capacity additions that are decided by LEAP regarding the type and amount to add based on generation technology and fuel costs, subject to constraints on generation capacity (maximum overall capacity in each year and the maximum capacity that can be added in a particular year), energy (setting an upper limit on the availability of generation processes and minimum fraction of hours that each process is utilised in each time slice) and renewable targets to be attained by specified projected years.

The first difference between HA1 (Optimised) and HA2 (Optimised) is that there is no maximum overall capacity constraints set for geothermal and coal and biomass cogeneration plants in the former unlike the latter. The second difference is that HA1 (Optimised) does not set a Renewable Portfolio Standard (RPS) constraint while HA2 (Optimised) does. The third difference is that the minimum utilisation of WTE plants (as the only remaining high-polluting electricity generation source in 2050) is reduced by 2050 in HA2 (Optimised) while it remains at the current load factor in HA1 (Optimised).

[106] Note that HA1 (Optimised), despite the naming, is not related to the HA1 scenario in our simulation exercise.

Essentially, HA2 (Optimised) is geared towards achieving near net zero emissions in the power sector (<1 $MtCO_2e$) by 2050 while HA1 (Optimised) relaxes these three constraints, limiting only to capacity addition size constraints to maintain a stronger influence of technology and fuel costs on endogenous capacity additions and dispatch of power plants.

To reflect technical constraints on the deployment of clean energy technologies and to allow for an uninterrupted phasing out or reduction of fossil-fuel and dirtier generation technologies, we added constraints on annual maximum capacity additions for HA1 (Optimised) and HA2 (Optimised), and annual maximum overall capacities for HA2 (Optimised), as illustrated in Table 6. For both scenarios, we assume that for fossil fuel and WTE plants, no further endogenous capacity additions are allowed in the projection period. For nuclear, geothermal, solar PV, hydrogen and low-carbon ammonia power plants as well as electricity imports, we specified the same endogenous maximum capacities that can be added in each projected year using the same values in the simulation exercise regarding endogenous capacity additions.

In HA1 (Optimised) and HA2 (Optimised): For coal and biomass cogeneration plants, as the feedstock fuel share between coal bituminous and biomass improves over time, at 46% coal bituminous and 53% biomass in 2032 in BAU (Optimised) and HA (Optimised) respectively, we allow for endogenous capacity additions of 44.5 MW starting from 2032, which is equivalent to 1/3 the generation capacity of the Tembusu Multi-Utilities Complex. For BESS, we assume that only 7.5 MW can be added annually from 2025, which is equivalent to the capacity of the upcoming floating BESS.

In HA2 (Optimised): For geothermal plants, assuming that Singapore's presently unexplored geothermal potential continues to be low in the future, we assume that the maximum overall capacity in each year can only be 250 MW or 5 of such geothermal plants (EMA, 2022a). For coal and biomass cogeneration plants, considering the net greenhouse gas outcome of emissions from the coal fuel component and the challenges of biomass importation, we assume that the maximum overall capacity in each year can only be 400.5 MW (equivalent to the maximum generating capacity of 3 existing Tembusu Multi-Utilities Complexes combined). For solar PV, maximum capacity additions already ensure that it will not exceed the maximum solar technical deployment potential of 8.6 GW in Singapore.

Like the simulation exercise, maximum availabilities of generation processes in both scenarios are set at 90% for all processes (including BESS in this case) except for solar PV, which depends on the yearly solar availability shape. To ensure that there is no power generator that is not dispatched to produce electricity even when there is available generation capacity, we assume the load factor (percentage use of capacity) for Singapore's electricity generation sector which is 50.3% in 2023 to be the minimum utilisation for existing and upcoming power generation plants as well as electricity imports[107]. For solar PV, the yearly solar availability shape was again used to determine the minimum utilisation. The minimum utilisation of WTE plants is linearly reduced to 45.34% by 2050 in HA2 (Optimised), which is equivalent to the average of the load factors between 2001-2023, while it remains at 50.3% in HA1 (Optimised).

In determining the extent to which each generation process is qualified as renewable, the fuel mix is considered (Table 7). Electricity produced by geothermal and solar PV generation processes as well as electricity imports (green electricity) are considered to be 100% renewable. As uranium fuel that is used to generate electricity is non-renewable, we consider nuclear-produced electricity to be non-renewable along with natural gas and oil-produced electricity. Only 30% of coal- and biomass-cogenerated electricity is initially considered to be renewable but increases to 100% by 2050 following the greater proportion of biomass in the mix and phasing out of coal by 2050 in both HA Optimised scenarios. For hydrogen power plants, to determine the renewability of electricity produced, we consider both the composition

[107] Incidentally, for electricity imports, maximum penalties will apply to the supplier when the quarterly load factor is at 50% or less, according to EMA's penalty framework for electricity imports (EMA, 2022b).

of natural gas (70%) and hydrogen (30%) in the production of hydrogen blend as well as the changing feedstock fuel shares of natural gas, hydrogen blend and green hydrogen in the fuel mix in 2035 and 2050. For low-carbon ammonia power plants, we assume that 75% of electricity produced is considered as renewable as we modelled low-carbon ammonia to be made up of 25% natural gas and 75% hydrogen. According to Europe's Department of Energy and Climate Change, 50% of power generated by cogeneration WTE plants is eligible for Renewables Obligation Certificates (ROCs)[108], thus we assumed that 50% of Singapore's WTE plants electricity production is renewable. For HA2 (Optimised), we specified that a minimum 30% of electricity produced needs to be renewable in 2030, increasing to a minimum of 99.3% electricity produced from renewable sources in 2050.

Due to computational limitations, annual energy demands were divided by 168 time slices (whole year/7 days of the week/24 hours) instead of 2016 time slices (12 months/7 days of the week/24 hours) as was the case in the simulation exercise. We posit the optimisation results produced with the lower time slice resolution are unlikely to differ significantly from that with the higher time slice resolution as the average monthly difference in percentage of peak load of each hour in each day of the week in terms of solar energy received is only about 4.4%.

[108] https://zerowasteeurope.eu/2015/08/is-waste-a-source-of-renewable-energy/

**Table 6: Optimisation parameters of power generation processes**

| Generation process | Maximum availability | Minimum utilisation | Maximum capacity | Maximum capacity addition |
|---|---|---|---|---|
| Natural gas OCGT | 90% | 50.3% | Unlimited | 0 MW |
| Natural gas CCGT | 90% | 50.3% | Unlimited | 0 MW |
| Diesel | 90% | 50.3% | Unlimited | 0 MW |
| Nuclear | 90% | 50.3% | Unlimited | 300 MW from 2040 |
| WTE | 90% | 50.3% (-> 45.34% in 2050 in HA2 Optimised) | Unlimited | 0 MW |
| Geothermal | 90% | 50.3% | 250 MW [HA2 Optimised) / Unlimited (HA1 Optimised) | 50 MW from 2040 |
| Solar PV | Based on solar irradiation availability for 168 time slices | Based on solar irradiation availability for 168 time slices | Unlimited | 330 MW from 2031 |
| Coal (with biomass co-firing) | 90% | 50.3% | 400.5 MW [HA2 Optimised) / Unlimited (HA1 Optimised) | 44.5 MW from 2032 |
| Hydrogen | 90% | 50.3% | Unlimited | 200 MW from 2027 |
| Low-carbon ammonia | 90% | 50.3% | Unlimited | 60 MW from 2027 |
| Electricity imports | 90% | 50.3% | Unlimited | 338 MW from 2032 |
| BESS | 90% | 0% | Unlimited | 7.5 MW from 2025 |

### Table 7: Determination of selected renewable-qualified feedstock fuel shares

<table>
<tr><th>Generation process</th><th>Year</th><th colspan="2">Feedstock fuel combusted for electricity generation</th><th>Feedstock fuel share for electricity generation (HA1 Optimised and HA2 Optimised)</th><th>Renewable qualified by fuel type for electricity generation (HA1 Optimised and HA2 Optimised)</th></tr>
<tr><td rowspan="12">Hydrogen power plant</td><td rowspan="4">2026</td><td colspan="2">Natural gas</td><td>70%</td><td>0%</td></tr>
<tr><td rowspan="2">Hydrogen blend</td><td>30% hydrogen</td><td rowspan="2">30%</td><td rowspan="2">9% (30% * 30%)</td></tr>
<tr><td>70% natural gas</td></tr>
<tr><td colspan="2">Hydrogen</td><td>0%</td><td>0%</td></tr>
<tr><td rowspan="4">2035</td><td colspan="2">Natural gas</td><td>12.5%</td><td>0%</td></tr>
<tr><td rowspan="2">Hydrogen blend</td><td>30% hydrogen</td><td rowspan="2">50%</td><td rowspan="2">15% (30% * 50%)</td></tr>
<tr><td>70% natural gas</td></tr>
<tr><td colspan="2">Hydrogen</td><td>37.5%</td><td>37.5% (100% * 37.5%)</td></tr>
<tr><td rowspan="4">2050</td><td colspan="2">Natural gas</td><td>0%</td><td>0%</td></tr>
<tr><td rowspan="2">Hydrogen blend</td><td>30% hydrogen</td><td rowspan="2">0%</td><td rowspan="2">0%</td></tr>
<tr><td>70% natural gas</td></tr>
<tr><td colspan="2">Hydrogen</td><td>100%</td><td>100%</td></tr>
<tr><td rowspan="4">Coal and biomass cogeneration power plant</td><td rowspan="2">2023</td><td colspan="2">Coal</td><td>70%</td><td>0%</td></tr>
<tr><td colspan="2">Biomass</td><td>30%</td><td>30%</td></tr>
<tr><td rowspan="2">2050</td><td colspan="2">Coal</td><td>0%</td><td>0%</td></tr>
<tr><td colspan="2">Biomass</td><td>100%</td><td>100%</td></tr>
<tr><td>WTE plants</td><td>N.A.</td><td colspan="2">MSW</td><td>100%</td><td>50%</td></tr>
<tr><td rowspan="2">Low-carbon ammonia</td><td rowspan="2">N.A.</td><td colspan="2">Blue Hydrogen</td><td>25%</td><td>0%</td></tr>
<tr><td colspan="2">Hydrogen</td><td>75%</td><td>75%</td></tr>
<tr><td>Nuclear power plants</td><td>N.A.</td><td colspan="2">Nuclear</td><td>100%</td><td>0%</td></tr>
<tr><td>Solar PV</td><td>N.A.</td><td colspan="2">Solar PV</td><td>100%</td><td>100%</td></tr>
<tr><td>Geothermal power plants</td><td>N.A.</td><td colspan="2">Geothermal</td><td>100%</td><td>100%</td></tr>
<tr><td>Electricity imports</td><td>N.A.</td><td colspan="2">N.A.</td><td>N.A.</td><td>100%</td></tr>
</table>

# 9. RESULTS & ANALYSIS (OPTIMISATION)

In this section, we present the optimisation results of our HA1 (Optimised) and HA2 (Optimised) scenarios.

## 9.1 Share of electricity generation by technology (outputs by feedstock fuel)

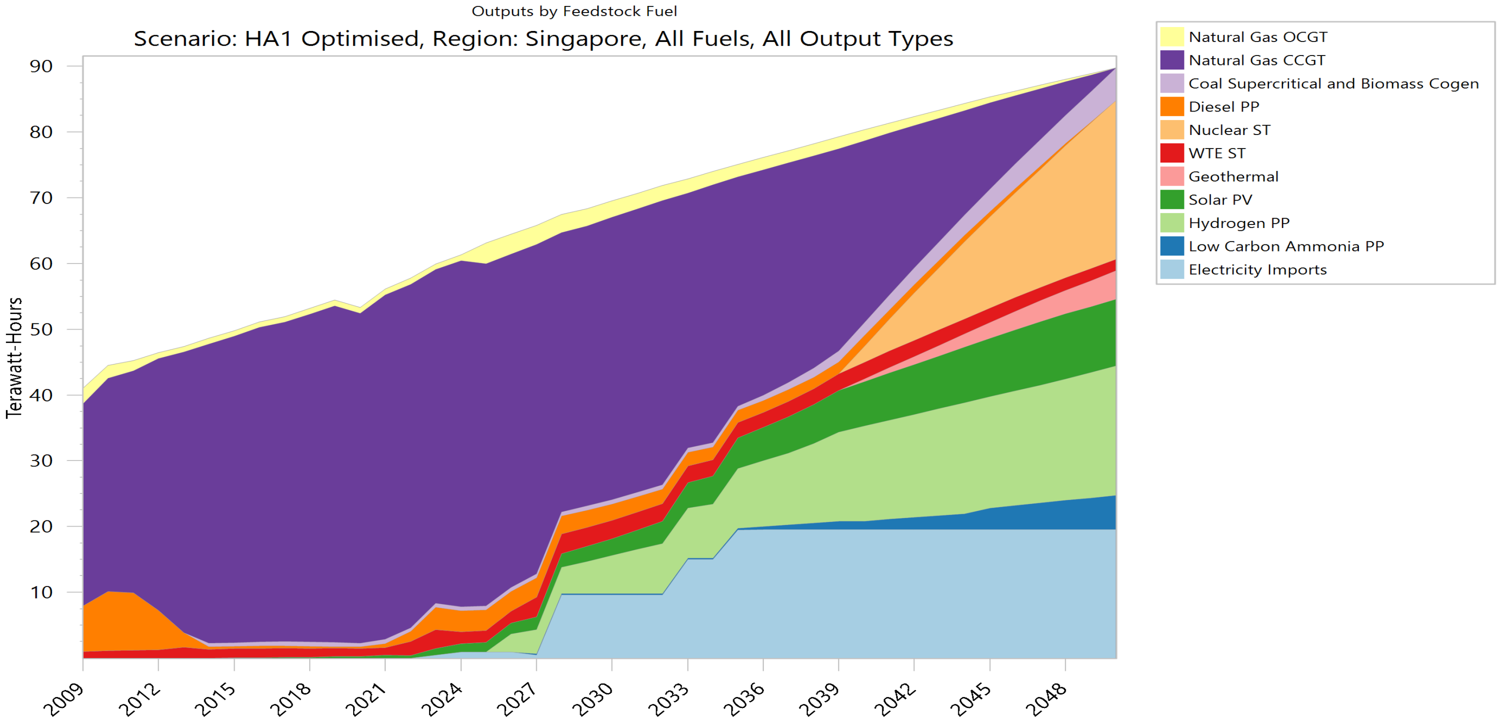


Figure 29: Absolute share of electricity generation by technology (HA1 Optimised)

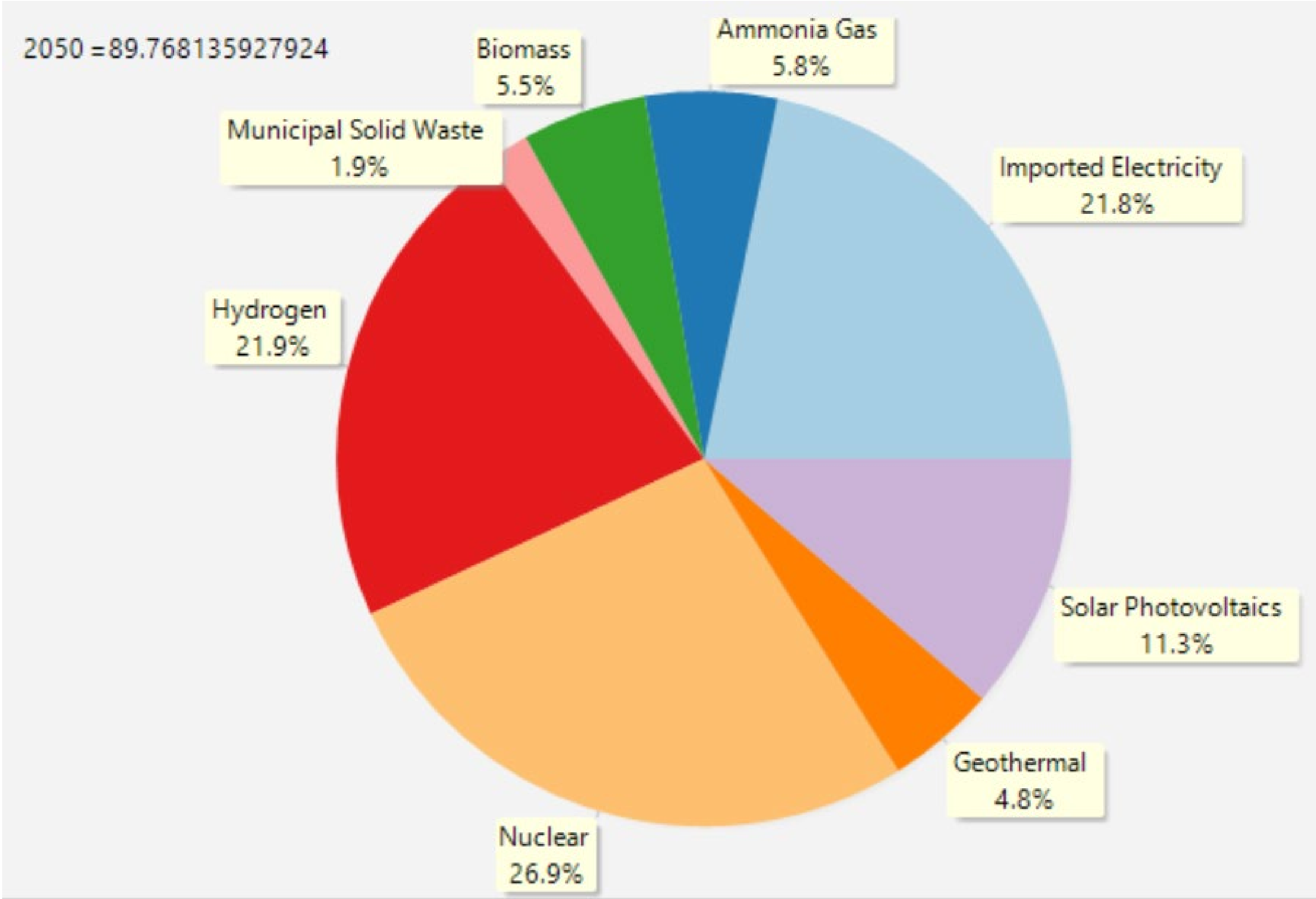


Figure 30: Percentage share of electricity generation by feedstock fuel type in 2050 (HA1 Optimised)

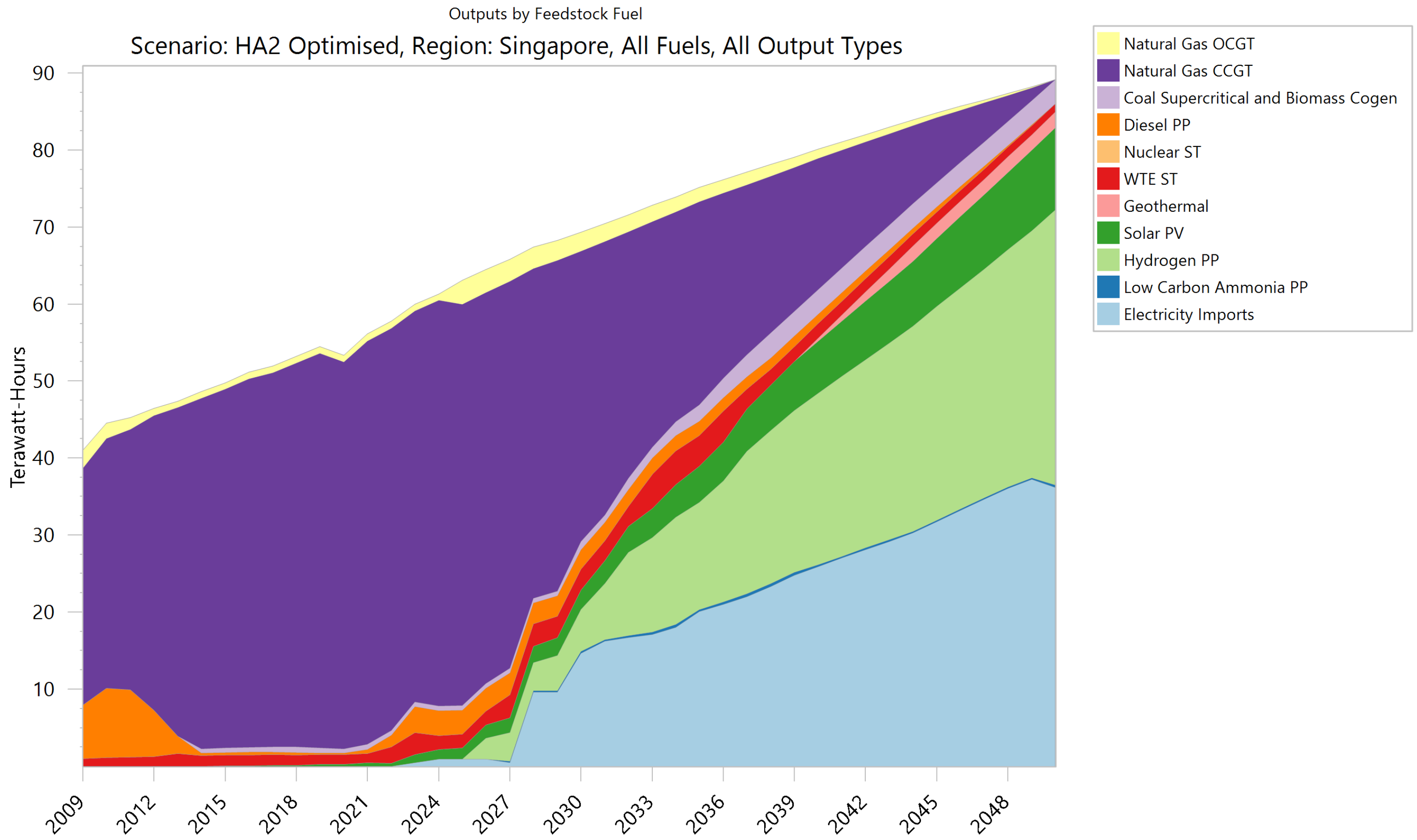


**Figure 31: Absolute share of electricity generation by technology (HA2 Optimised)**

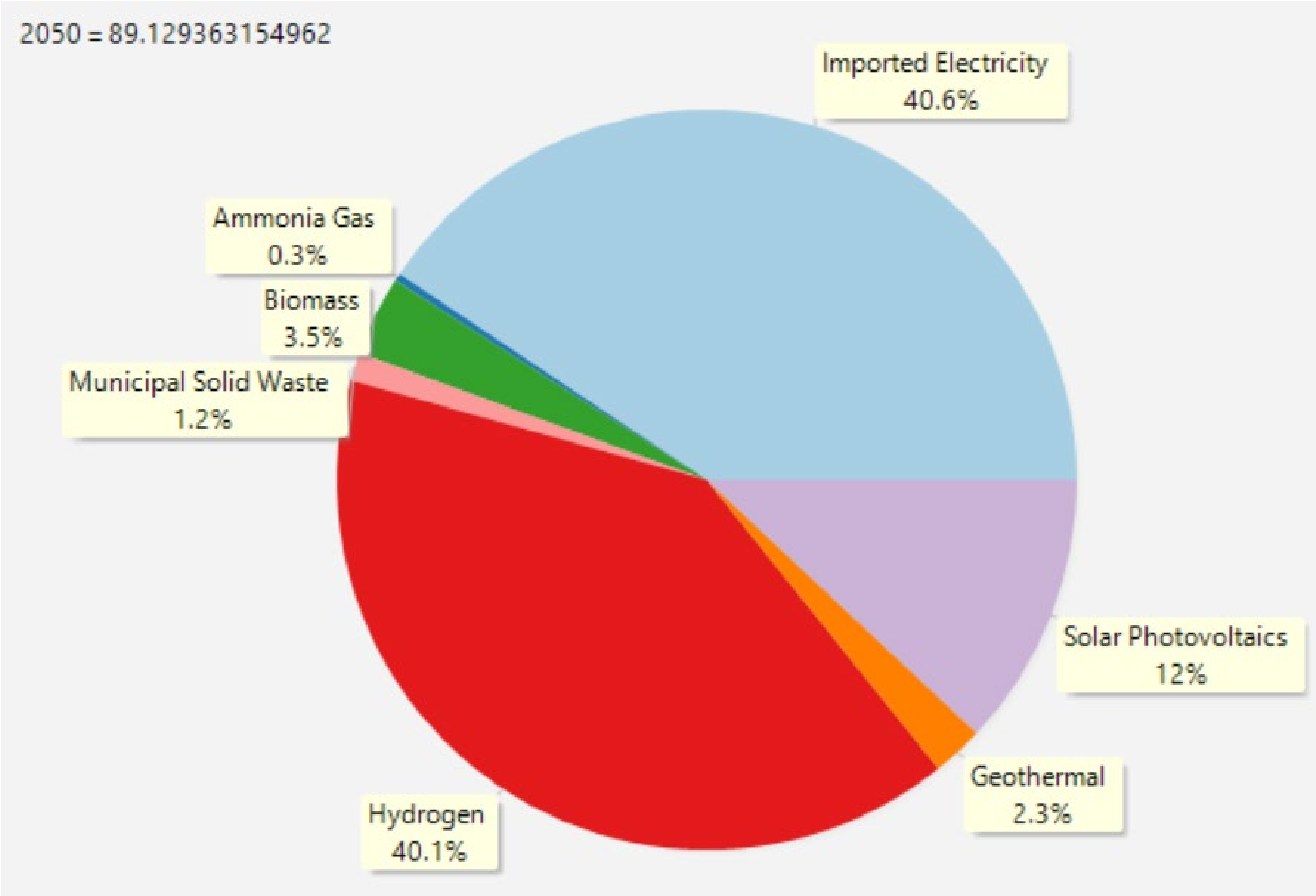


**Figure 32: Percentage share of electricity generation by feedstock fuel type in 2050 (HA2 Optimised)**

In HA1 (Optimised), power generation is projected to increase to 89.8 TWh by 2050. The combined electricity generated by hydrogen-compatible and low-carbon ammonia power plants increases at an average annual rate of 24.8%, constituting 24.9 TWh (27.7%) in 2050. Imported electricity increases at an average annual rate of 78.7%, constituting 26% of Singapore's projected energy supply in 2035 and reaching 19.6 TWh (21.8%) in 2050. Solar PV-generated electricity increases at an average annual rate of 8.9%, meeting 3.9% of projected total electricity demand in 2030 and reaching 10.1 TWh (11.3%) in 2050.

After the two new replacement OCGT units are built in 2025, natural gas-generated electricity decreases at an average annual rate of 21.2% and is phased out in 2050. Oil-generated electricity decreases at an average annual rate of 10% and is phased out in 2050. WTE--generated electricity decreases at an average annual rate of 0.8%, reaching 1.7 TWh (1.9%) in 2050. Coal- and biomass-generated electricity increases at an average annual rate of 8.5%, reaching 4.9 TWh in 2050, constituting 5.5% share. Nuclear-generated electricity increases at an average annual rate of 28.2%, reaching 24.2 TWh (26.9%) in 2050. Geothermal-generated electricity increases at an average annual rate of 29%, reaching 4.3 TWh (4.8%) in 2050.

Under HA1 (Optimised), we would expect to see a future where Singapore's energy portfolio is portfolio is diversified in cleaner energy sources in 2050 (hydrogen, imported electricity and nuclear). The reserve margin is expected to remain nearly equal to or above the planning reserve margin of 27% throughout the other projection years.

In HA1 (Optimised), hydrogen-compatible with low-carbon ammonia power generators, imported electricity and solar PV can supply about 29.1%, 22.8% and 11.8% of Singapore's energy needs respectively by 2050. Moreover, nuclear and geothermal power generators can supply about 28.2% and 5% of Singapore's energy needs respectively by 2050.

In HA2 (Optimised), power generation is projected to increase to 89.1 TWh by 2050. The combined electricity generated by hydrogen-compatible and low-carbon ammonia power plants increases at an average annual rate of 14.5%, constituting 36 TWh (40.4%) in 2050. Imported electricity increases at an average annual rate of 80.9%, constituting 26.7% of Singapore's projected energy supply in 2035 and reaching 36.2 TWh (42.2%) in 2050. Solar PV-generated electricity increases at an average annual rate of 9.1%, meeting 3.8% of projected total electricity demand in 2030 and reaching 10.7 TWh (12%) in 2050.

After the two new replacement OCGT units are built in 2025, natural gas-generated electricity decreases at an average annual rate of 24.3% and is phased out in 2050. Oil-generated electricity decreases at an average annual rate of 11.2% and is phased out in 2050. WTE--generated electricity decreases at an average annual rate of 1.4%, reaching 1.1 TWh (1.2%) in 2050. Coal- and biomass-generated electricity increases at an average annual rate of 7.5%, reaching 3.1 TWh in 2050, constituting 3.5% share. No electricity is produced by nuclear power plants. Geothermal-generated electricity increases at an average annual rate of 20.8%, reaching 2 TWh (2.3%) in 2050.

Under HA2 (Optimised), we would expect to see a future where Singapore's energy portfolio is also diversified in cleaner energy sources in 2050 (hydrogen and imported electricity). The reserve margin is expected to remain nearly equal to or above the planning reserve margin of 27% throughout the other projection years.

In HA2 (Optimised), hydrogen-compatible with low-carbon ammonia power generators, imported electricity and solar PV can supply about 42.1%, 42.2% and 12.5% of Singapore's energy needs respectively by 2050. Moreover, geothermal power generators can supply about 2.3% of Singapore's energy needs respectively by 2050.

## 9.2 Fuel consumption in the power sector

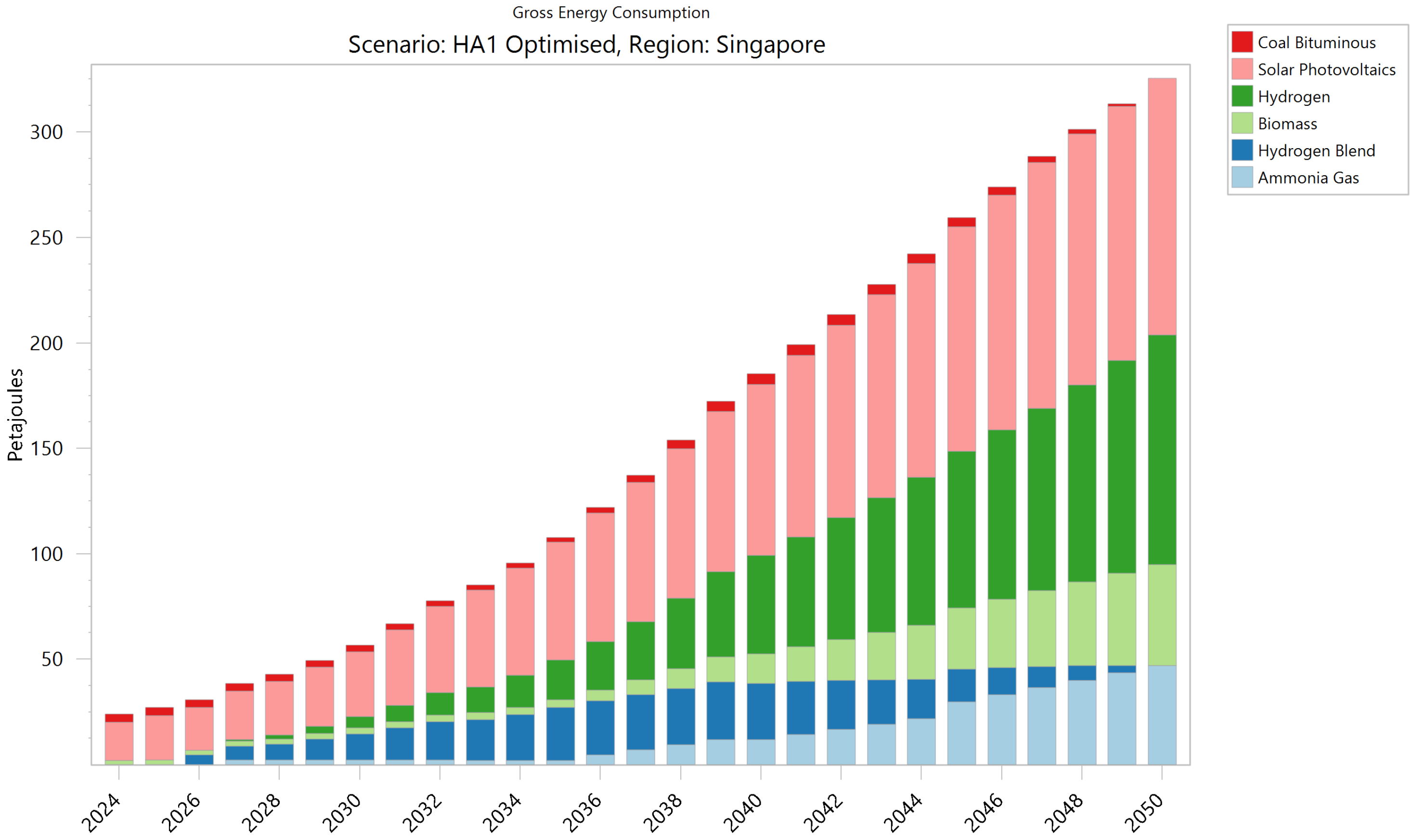


**Figure 33: Consumption of selected feedstock fuels in the power sector (HA1 Optimised)**

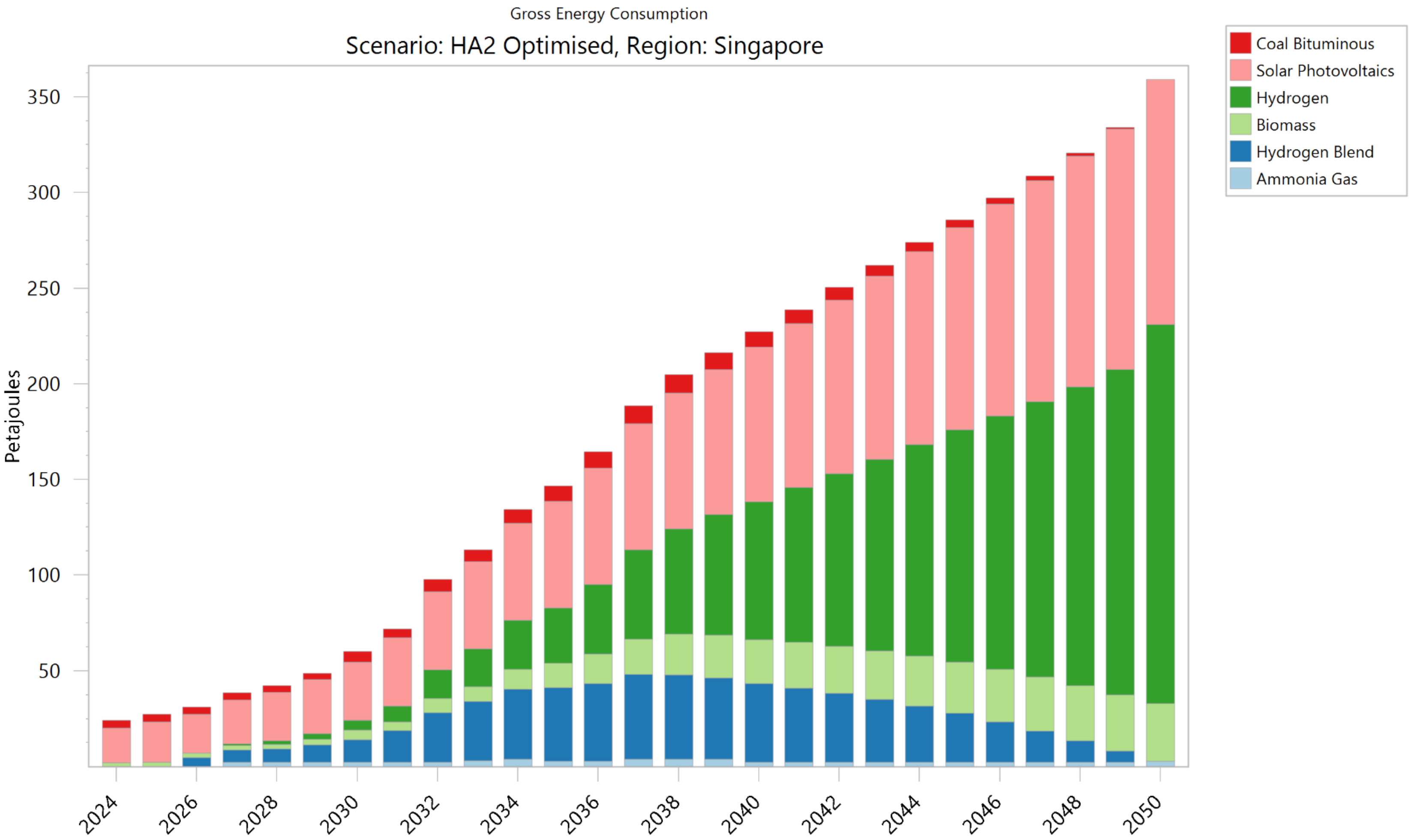


**Figure 34: Consumption of selected feedstock fuels in the power sector (HA2 Optimised)**

In HA1 (Optimised), the amount of hydrogen blend consumed generally increases from 4.6 PJ in 2026 to a peak of 27.4 PJ in 2039 (average annual increase of 15.4%), before steadily decreasing to be phased out in 2050 (average annual decrease of 17.3%).

The amount of hydrogen consumed starts out at 0.8 PJ in 2027 and generally increases to 109 PJ in 2050 (average annual increase of 25.8%). The amount of low-carbon ammonia consumed starts out at 2.1 PJ in 2027, remains fairly constant until 2035 and then increasing to 46.9 PJ in 2050 (average annual increase of 16.7%).

There is a net decrease in the amount of coal consumed from 4 PJ in 2024 to being phased out in 2050 (net average annual decrease of 3.6%). There is a net increase in the amount of biomass consumed from 1.9 PJ in 2024 to 48 PJ in 2050 (average annual increase of 13.4%).

There is a net increase in the amount of solar PV energy consumed from 18.1 PJ in 2024 to 121.7 PJ in 2050 (average annual increase of 8.2%).

In HA2 (Optimised), the amount of hydrogen blend consumed generally increases from 4.6 PJ in 2026 to a peak of 44.4 PJ in 2037 (average annual increase of 24.1%), before steadily decreasing to be phased out in 2050 (average annual decrease of 14.3%).

The amount of hydrogen consumed starts out at 0.8 PJ in 2027 and generally increases to 198 PJ in 2050 (average annual increase of 29.3%). The amount of low-carbon ammonia consumed starts out at 2.1 PJ in 2027, exhibits a fluctuating trend and reaches 2.7 PJ in 2050 (average annual increase of 2.8%).

There is a net decrease in the amount of coal consumed from 4 PJ in 2024 to being phased out in 2050 (net average annual decrease of 3.8%). There is a net increase in the amount of biomass consumed from 1.9 PJ in 2024 to 30.2 PJ in 2050 (average annual increase of 12.4%).

There is a net increase in the amount of solar PV energy consumed from 18.1 PJ in 2024 to 128.2 PJ in 2050 (average annual increase of 8.4%).

## 9.3 Share of installed generation capacity by technology (endogenous)

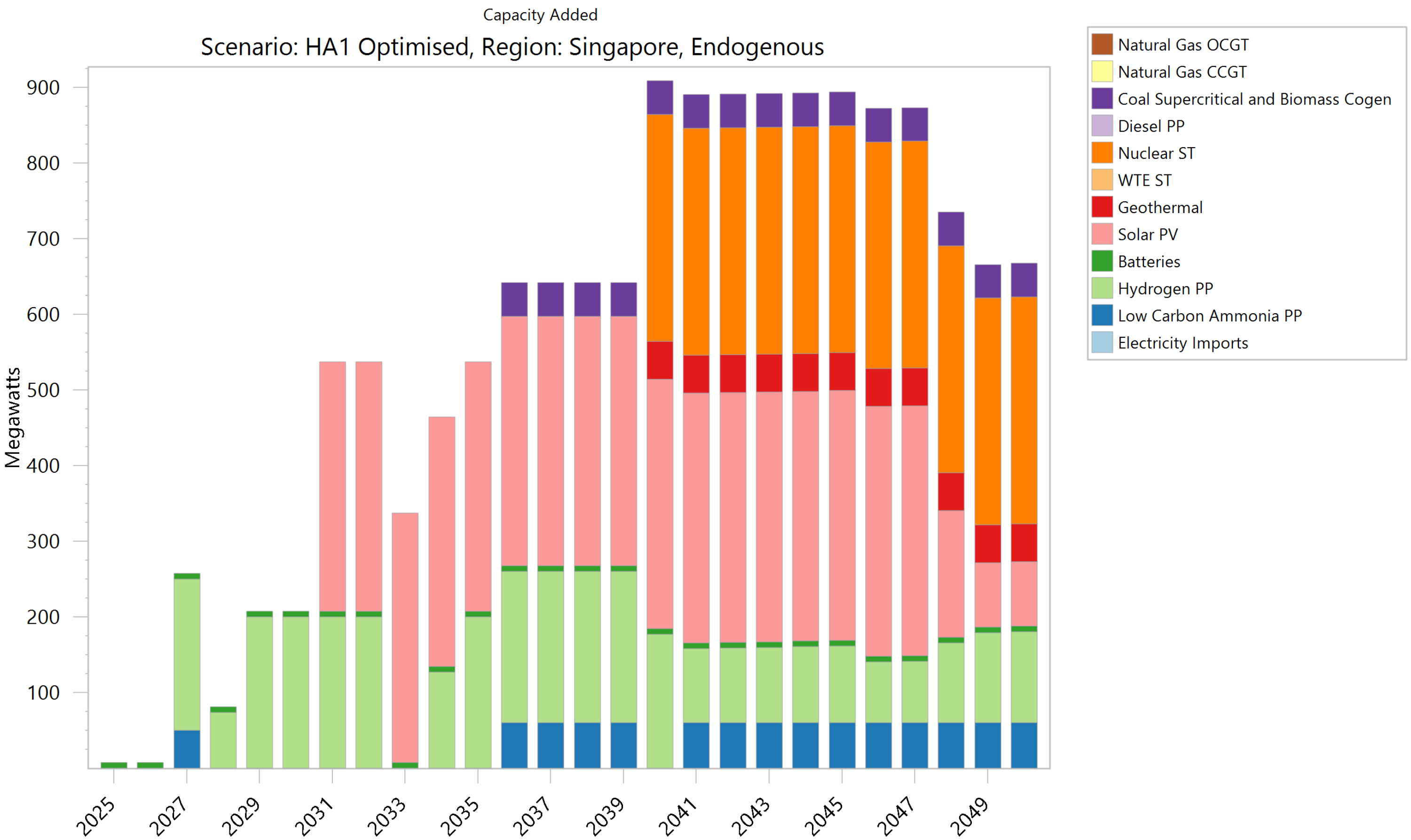


**Figure 35: Share of endogenous generation capacity added by technology (HA1 Optimised)**

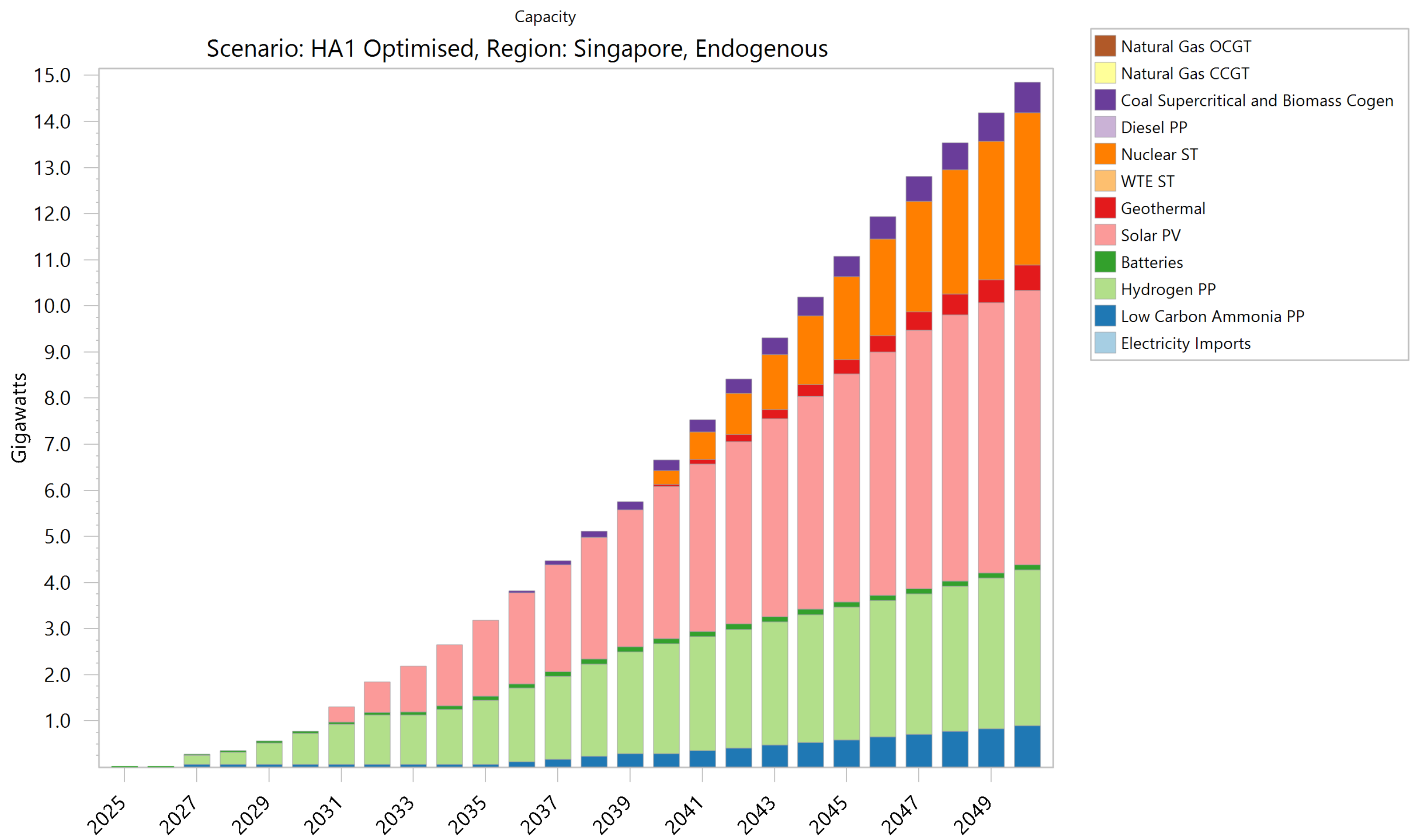


**Figure 36: Share of endogenous generation capacity added by technology (HA2 Optimised)**

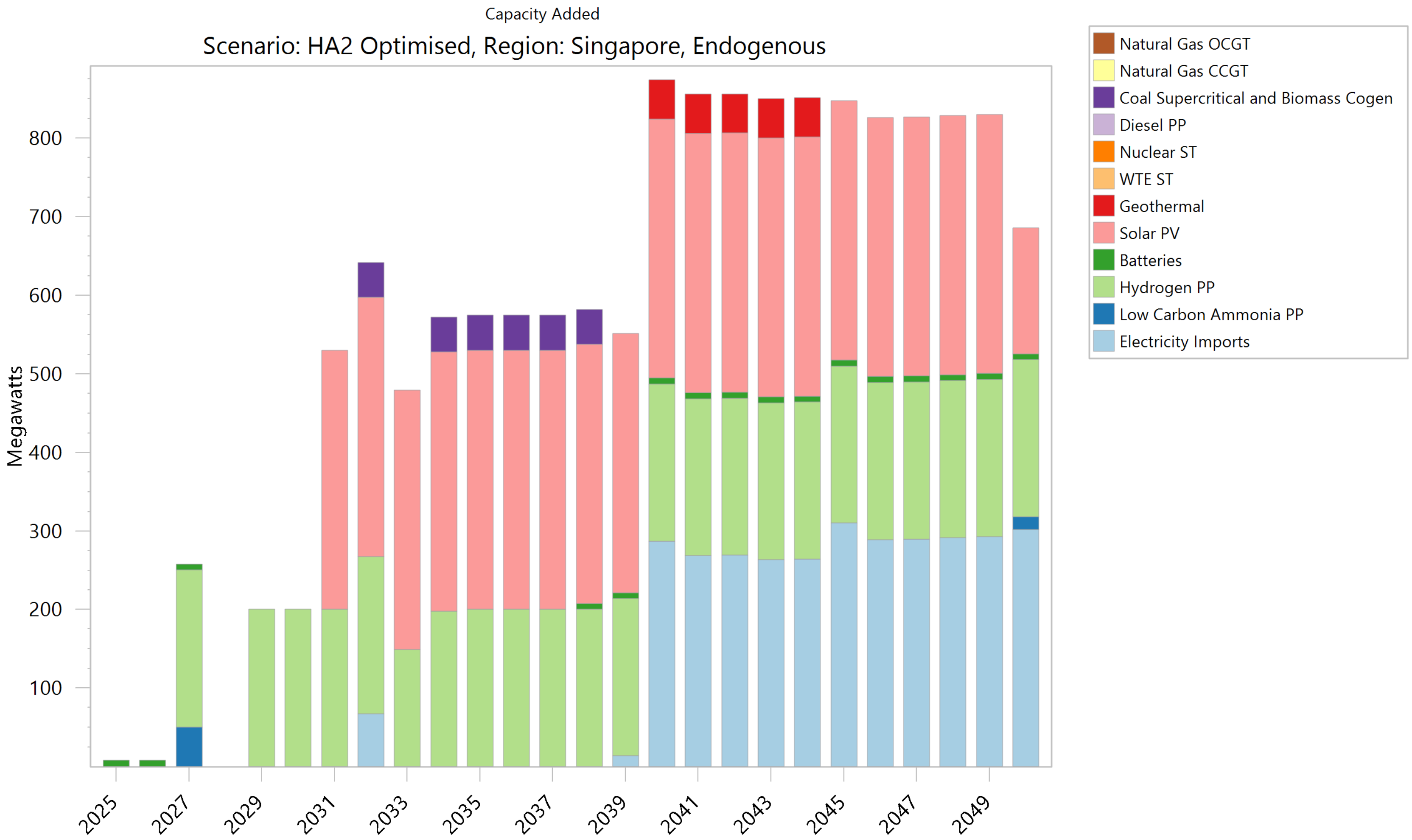


**Figure 37: Share of overall endogenous generation capacity by technology (HA1 Optimised)**

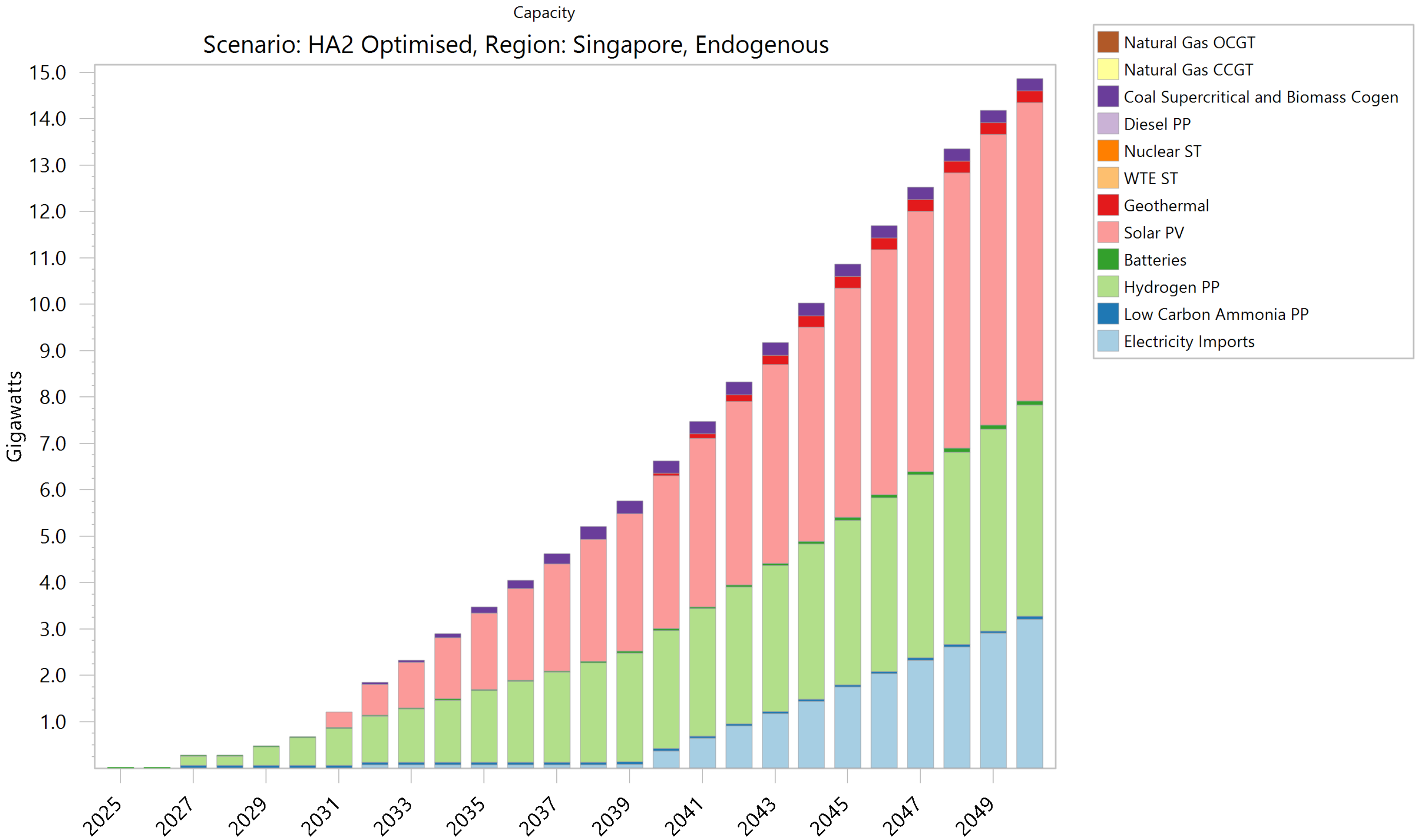


**Figure 38: Share of overall endogenous generation capacity by technology (HA2 Optimised)**

In HA1 (Optimised): 300 MW of nuclear generation capacity and 50 MW of geothermal generation capacity need to be endogenously added annually from 2040-2050 respectively. 330 MW of solar PV capacity needs to be endogenously added annually from 2031-2047, followed by 167.5 MW in 2048, 84.8 MW in 2049 and 85.5 MW in 2050.

200 MW of hydrogen generation capacity needs to be endogenously added in 2027, followed by 73.5 MW in 2028, 200 MW from 2029-2032, 126.8 MW in 2034, 200 MW from 2035-2039, 176.9 MW in 2040, 98.3 MW in 2041, 99 MW in 2042, 99.7 MW in 2043, 100.7 MW in 2044, 101.7 MW in 2045, 80.6 MW in 2046, 81.3 MW in 2047, 105.8 MW in 2048, 119 MW in 2049 and 120.2 MW in 2050.

50.2 MW[109] of low-carbon ammonia generation capacity needs to be endogenously added in 2027, followed by 60 MW annually from 2036-2039 and 2041-2050. 44.5 MW of coal and biomass cogeneration capacity needs to be endogenously added annually from 2036-2050. 7.5 MW of BESS needs to be endogenously added annually from 2025-2050.

In terms of the cumulative amount added: 3.3 GW of nuclear, 550 MW of geothermal, 5.9 GW of solar PV, 3.4 GW of hydrogen, 890.2 MW of low-carbon ammonia power generation capacity, 667.5 MW of coal and biomass cogeneration capacity, as well as 195 MW of BESS would have been endogenously added by 2050.

In HA2 (Optimised): 50 MW of geothermal generation capacity needs to be endogenously added annually from 2040-2044. 330 MW of solar PV capacity needs to be endogenously added annually from 2031-2049, followed by 160.6 MW In 2050.

200 MW of hydrogen generation capacity needs to be endogenously added in 2027 and 2029-2032, followed by 149 MW in 2033, 197.6 MW in 2034 and 200 MW from 2035-2050.

44.5 MW of coal and biomass cogeneration capacity needs to be endogenously added in 2032 and in 2034-2038.

67.2 MW of electricity imports needs to be endogenously added in 2032, followed by 13.8 MW in 2039, 287 MW in 2040, 268.4 MW in 2041, 269 MW in 2042, 263 MW in 2043, 264 MW in 2044, 310 MW in 2045, 288.9 MW in 2046, 289.6 MW in 2047, 291.2 MW in 2048, 292.8 MW in 2049 and 301.8 MW in 2050.

7.5 MW of BESS needs to be endogenously added from 2025-2027 and 2038-2050. 50.2 MW of low-carbon ammonia power generation capacity needs to be added in 2027, followed by 16.2 MW in 2050.

In terms of the cumulative amount added: 250 MW of geothermal, 6.4 GW of solar PV, 4.5 GW of hydrogen, 66.4 MW of low-carbon ammonia power generation capacity, 267 MW of coal and biomass cogeneration capacity, 120 MW of BESS, as well as 3.2 GW of electricity imports would have been endogenously added by 2050.

[109] Note that this is similar to the original minimum generation capacity proposed for the upcoming low-carbon ammonia power generation plant by 2027.

## 9.4 Energy generation of BESS

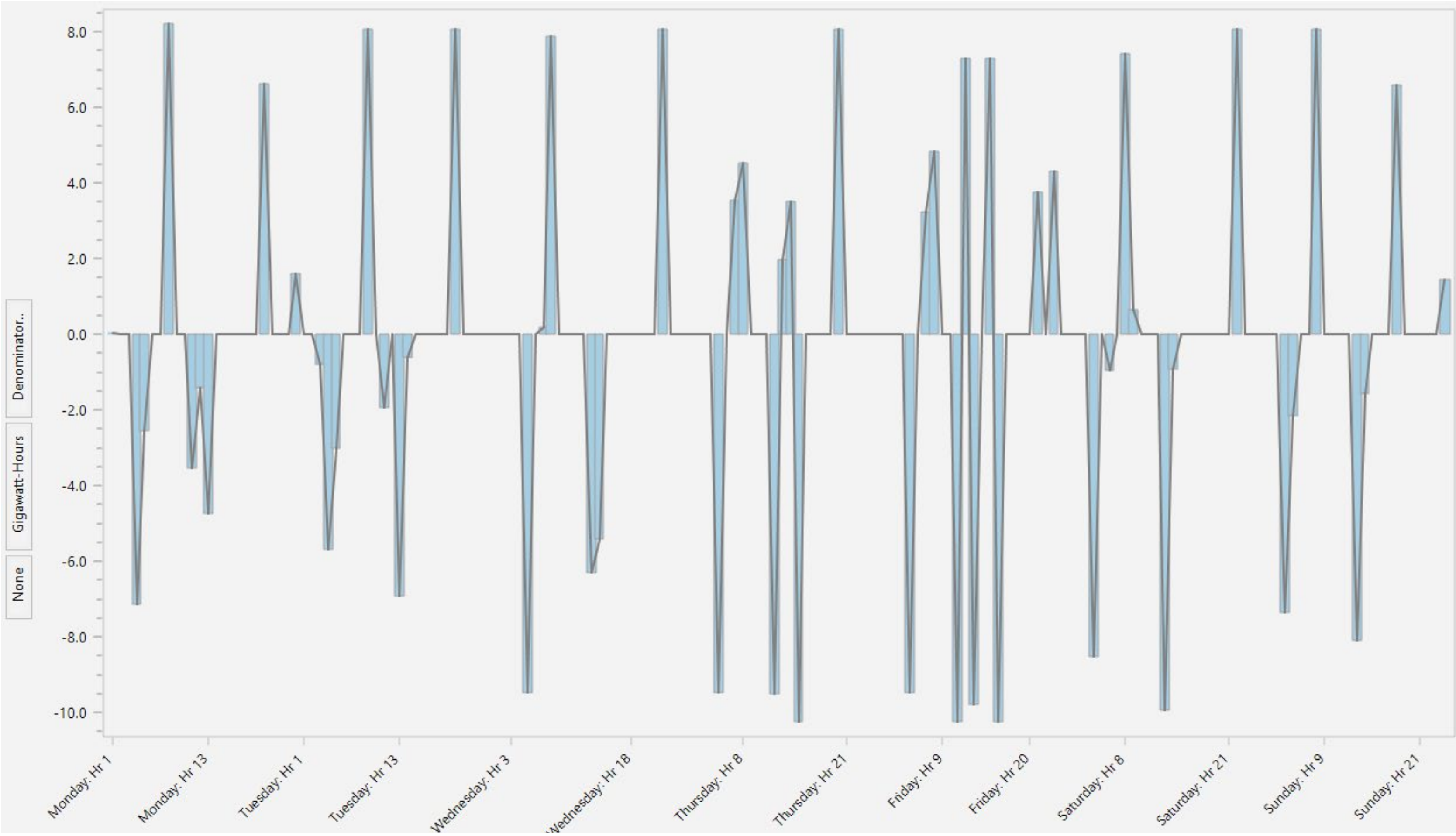


Figure 39: Energy generation of BESS (HA1 Optimised)

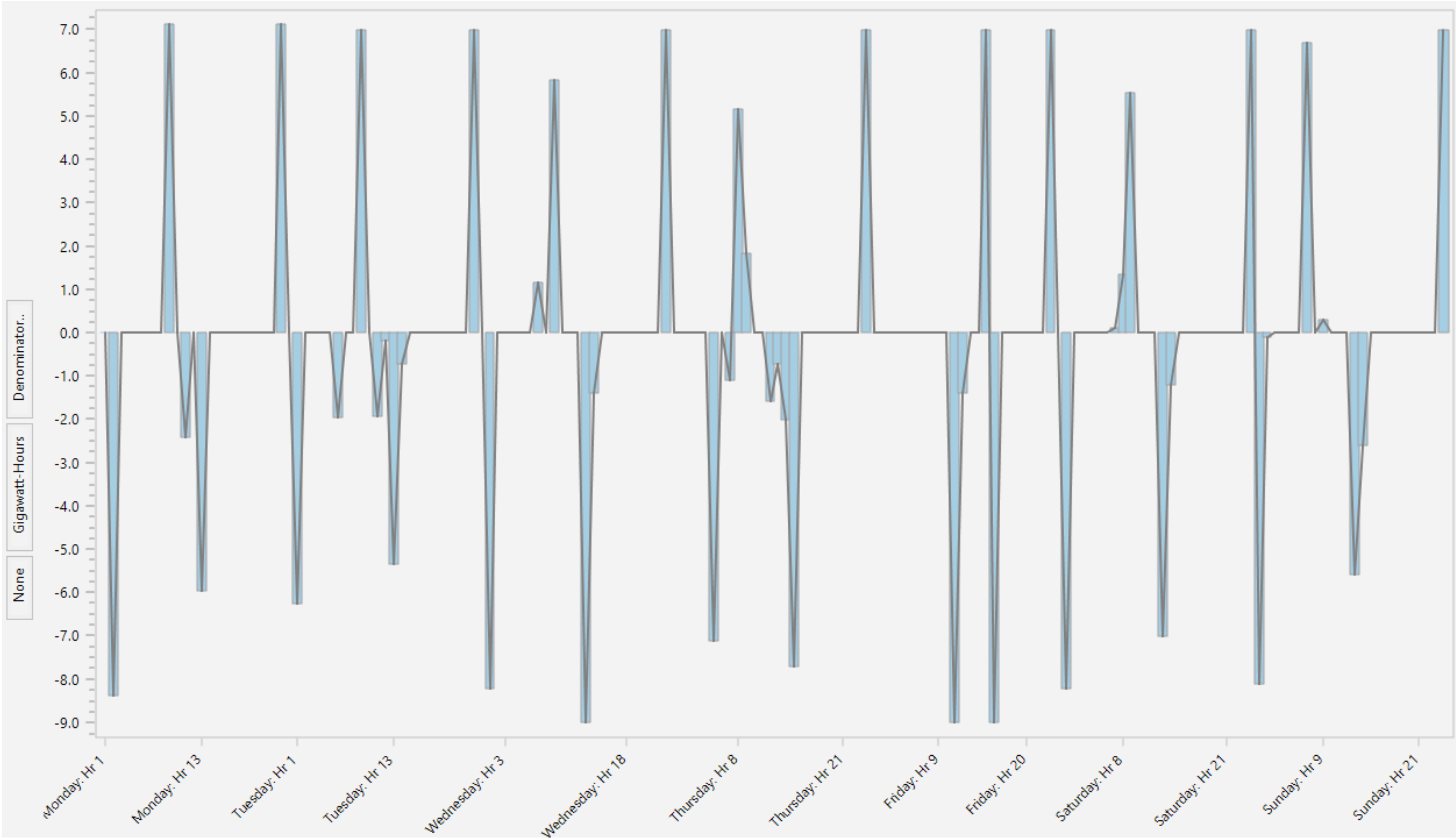


Figure 40: Energy generation of BESS (HA2 Optimised)

We examine the discharge-to-recharge rate of BESS in 2050[110] (Table 8). The positive portions indicate the amount of stored electricity that is dispatched by batteries during that particular time slice. The negative portions indicate that excess electricity produced is charging the batteries during that particular time slice.

On average, both scenarios exhibit a consistent pattern where, firstly, batteries are generally charged during early morning hours, likely capitalising on leftover capacity from the previous day's energy production, rather than being directly tied to low demand. Secondly, significant discharging mainly occurs in the evenings and later in the mornings across most days, correlating with peak energy demand periods and when solar production is insufficient. Thirdly, when charging during midday and early afternoon occurs, it suggests periods of excess generation from solar PV, indicating times when generated energy exceeds immediate consumption needs, allowing for battery storage.

Table 8: BESS activity summary in each day of the week

| Day of the week | | HA1 (Optimised) | HA2 (Optimised) |
|---|---|---|---|
| Monday | Early Morning | Begins with charging, peaking at -7.12 GWh by 4:00 AM. | Minimal activity with a notable charge at -8.38 GWh at 2:00 AM. |
| | Morning to Noon | Transition from charging early in the morning to discharging 8.22 GWh at 8:00 AM, followed by further charging later in the morning. | A discharge occurs at 7.12 GWh at 9:00 AM, followed by a charge of -2.42 GWh at 11:00 AM. |
| | Afternoon | Continues with charging of -4.74 GWh at 1:00 PM, with negligible activities for the rest of the afternoon. | Charging continues with -5.96 GWh at 1:00 PM, with no significant events afterwards. |
| | Evening | Discharging peaks early in the evening at 6.61 GWh at 8:00 PM, diminishing towards late evening. | Ends with the only discharge of 7.12 GWh at 11:00 PM. |
| Tuesday | Early Morning | Charging starts early at -0.78 GWh at 3:00 AM, reaching -5.70 GWh by 4:00 AM. | Starts with a charge of -6.25 GWh at 1:00 AM, followed by -1.97 GWh at 6:00 AM. |
| | Morning to Noon | Discharging of 8.06 GWh observed at 9:00 AM, shifting back to charging of -1.93 GWh at 11:00 AM. | Discharging of 6.99 GWh at 9:00 AM and minor charging at -1.93 GWh at 11:00 AM. |
| | Afternoon | Notable charging of -6.93 GWh at 1:00 PM, followed by low activity, maintaining stability into the evening. | Charges mildly throughout until 3:00 PM, peaking at -5.34 GWh at 1:00 PM. |
| | Evening | Concludes with a peak in discharging at 8.06 GWh at 8:00 PM. | Concludes with the only discharge of 6.99 GWh at 11:00 PM. |
| Wednesday | Early Morning | Starts with notable charging at -9.48 GWh at 5:00 AM. | Charging of -8.22 GWh at 1:00 AM. |
| | Morning to Noon | Mild charging to discharging transition with notable discharging of 7.88 GWh by 8:00 AM. | Starts with a minor discharge of 1.16 GWh at 7:00 AM, followed by a larger |

[110] This is aligned with the 168 time intervals into which annual energy demands are divided, as set up for the optimisation scenarios.

| | | | |
|---|---|---|---|
| | | | discharge of 5.83 GWh at 9:00 AM. |
| | Afternoon | Charging again at -6.3 GWh at 1:00 PM and -5.41 GWh at 2:00 PM. | Significant charging at -9.00 GWh at 1:00 PM, followed by a smaller amount of charging at 2:00 PM (-1.40 GWh) and a relatively quiet afternoon. |
| | Evening | Discharging peaks once more at 8.06 GWh at 10:00 PM. | Concludes with the only discharging of 6.99 GWh at 11:00 PM. |
| Thursday | Early Morning | Substantial charging at -9.48 GWh at 5:00 AM. | Charging of -7.12 GWh at 5:00 AM. |
| | Morning to Noon | Discharging of 3.55 GWh at 7:00 AM and 4.52 GWh at 8:00 AM, followed by notable charging of -9.50 GWh at noon. | Charging of -1.10 GWh at 7:00 AM, followed by discharging of 5.17 GWh at 8:00 AM and 1.82 GWh at 9:00 AM, then charging of -1.60 GWh at noon. |
| | Afternoon | Small discharging at 1:00 PM and 2:00 PM, followed by significant charging of -10.24 GWh at 3:00 PM. | Series of charging activities, peaking at -7.72 GWh at 3:00 PM. |
| | Evening | Ends with discharging of 8.06 GWh at 8:00 PM. | Concludes with a discharge of 6.99 GWh at midnight. |
| Friday | Early Morning | Intense charging at -9.48 GWh at 5:00 AM. | Negligible activity throughout. |
| | Morning to Noon | Moderate discharging at 7:00 AM and 8:00 PM, followed by charging of -10.24 GWh at 11:00 AM and transitions to discharging again (7.30 GWh) at noon. | Begins with notable charging of -9.00 GWh at 11:00 AM and a smaller amount of -1.40 GWh at noon. |
| | Afternoon | Charging observed again at -10.24 GWh by 4:00 PM. | Discharging of 6.99 GWh at 3:00 PM< followed by charging of -9.00 GWh at 4:00 PM. |
| | Evening | Mild discharging activity during the night at 9:00 PM (3.75 GWh) and 11:00 PM (4.32 GWh). | Ends with the only discharge of 6.99 GWh at 11:00 PM. |
| Saturday | Early Morning | Commences with charging at -8.52 GWh at 4:00 AM, with a very mild charging at 6:00 AM. | Charging of -8.22 GWh at 1:00 AM. |
| | Morning to Noon | Changes to discharging at 7.40 GWh at 8:00 AM, with a very mild discharging at 2:00 PM. | Mild discharging activities from 7:00 AM, peaking at 5.53 GWh at 9:00 AM. |
| | Afternoon | Notable charging of -9.93 GWh at 1:00 PM, with a very mild charging at 2:00 PM. | Charging of -7.02 GWh at 1:00 PM and a smaller amount of -1.20 GWh at 2:00 PM. |
| | Evening | Discharging peaks at 8.06 GWh at 10:00 PM. | Concludes with the only discharge of 6.99 GWh at midnight. |

| | | | |
|---|---|---|---|
| Sunday | Early Morning | Early morning charging of -7.34 GWh at 4:00 AM and -2.14 GWh at 5:00 AM. | Charging of -8.11 GWh at 1:00 AM, followed by minor charging at 2:00 AM. |
| | Morning to Noon | Switches to discharging at 8.06 GWh at 8:00 AM. | Begins with notable discharging of 6.70 GWh at 7:00 AM, followed by minor discharging at 9:00 AM. |
| | Afternoon | Charging activities at 1:00 PM (-9.09 GWh) and 2:00 PM (-1.58 GWh). | Charging of -5.60 GWh at 1:00 PM and a smaller amount of -2.62 GWh at 2:00 PM. |
| | Evening | Discharging of 6.59 GWh at 6:00 PM, tapering off by midnight. | Concludes with the only discharge of 6.99 GWh at midnight. |

## 9.5 Absolute emissions projections (100-Year GWP)

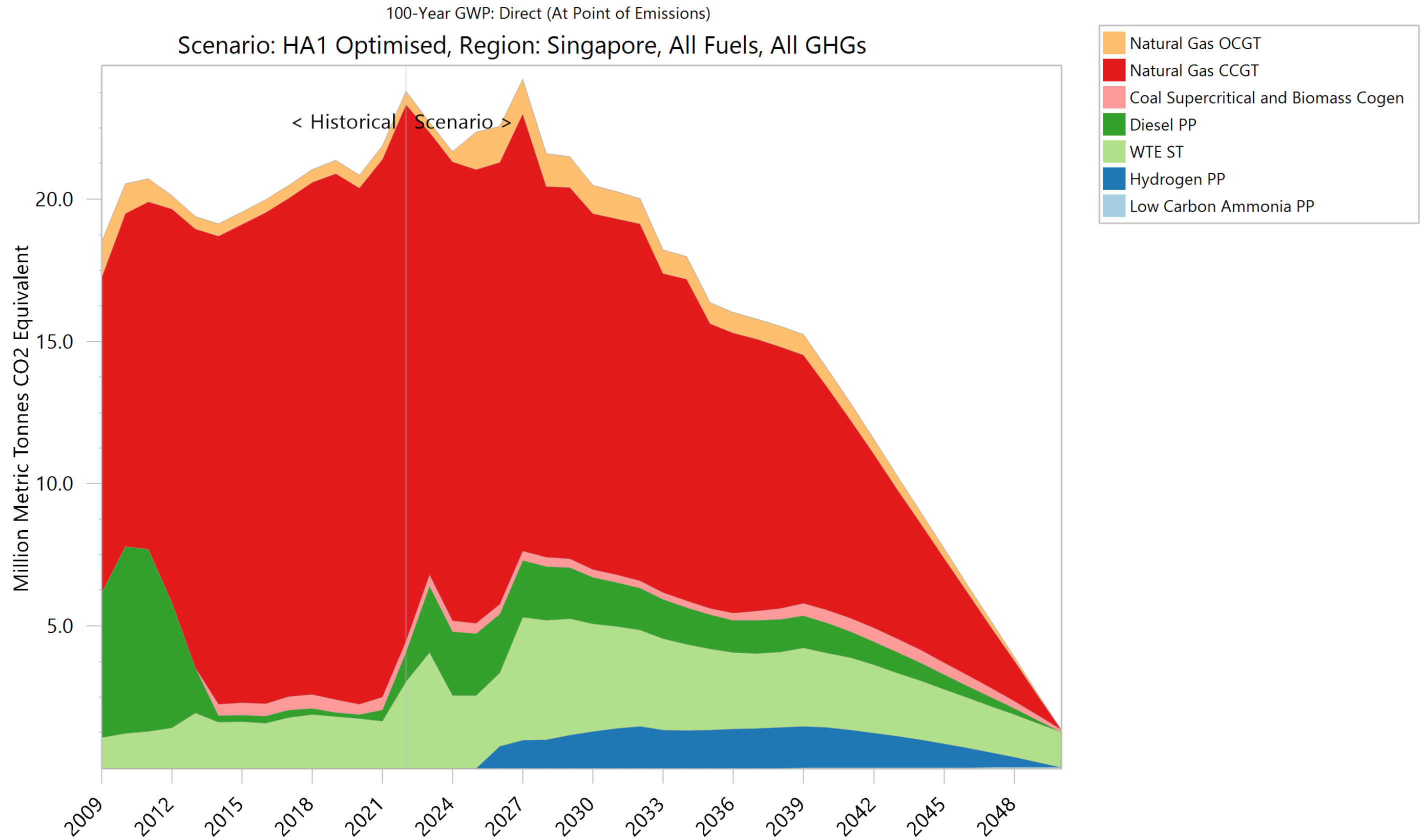


**Figure 41: Absolute share of emissions in power sector by technology (100-Year GWP) (HA1 Optimised)**

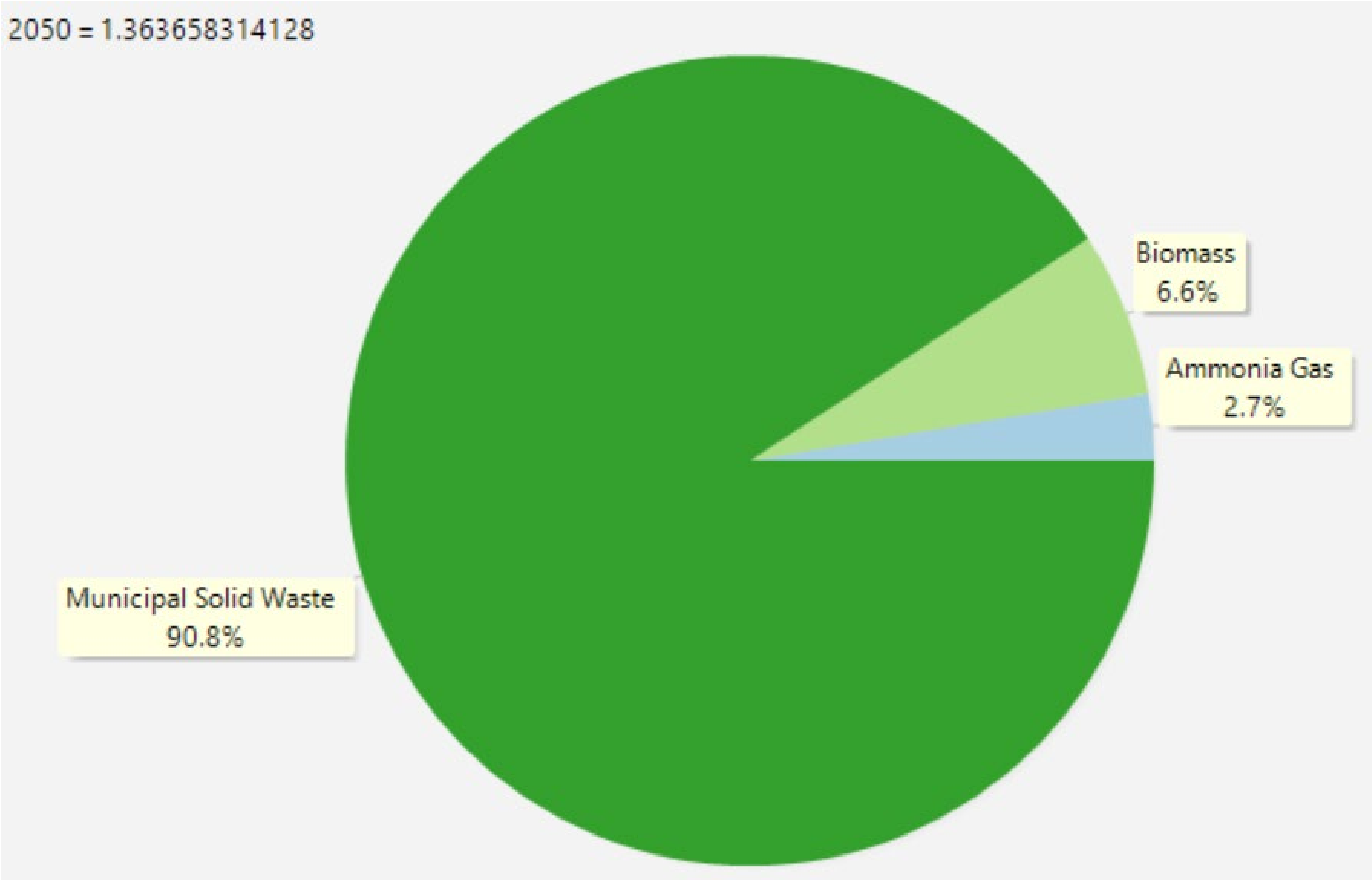


Figure 42: Percentage share of emissions in power sector by feedstock fuel type in 2050 (HA1 Optimised)

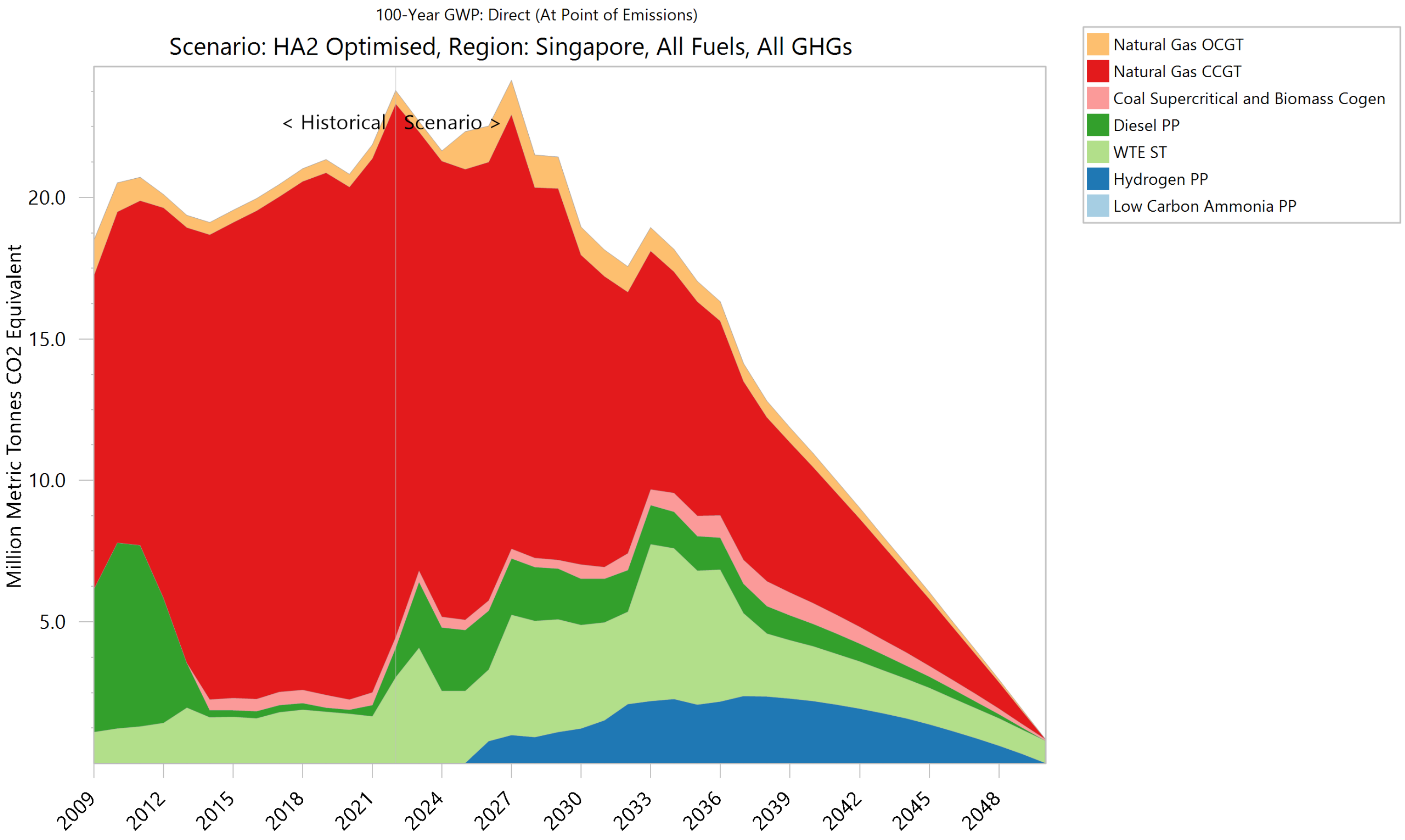


**Figure 43: Absolute share of emissions in power sector by technology (100-Year GWP) (HA2 Optimised)**

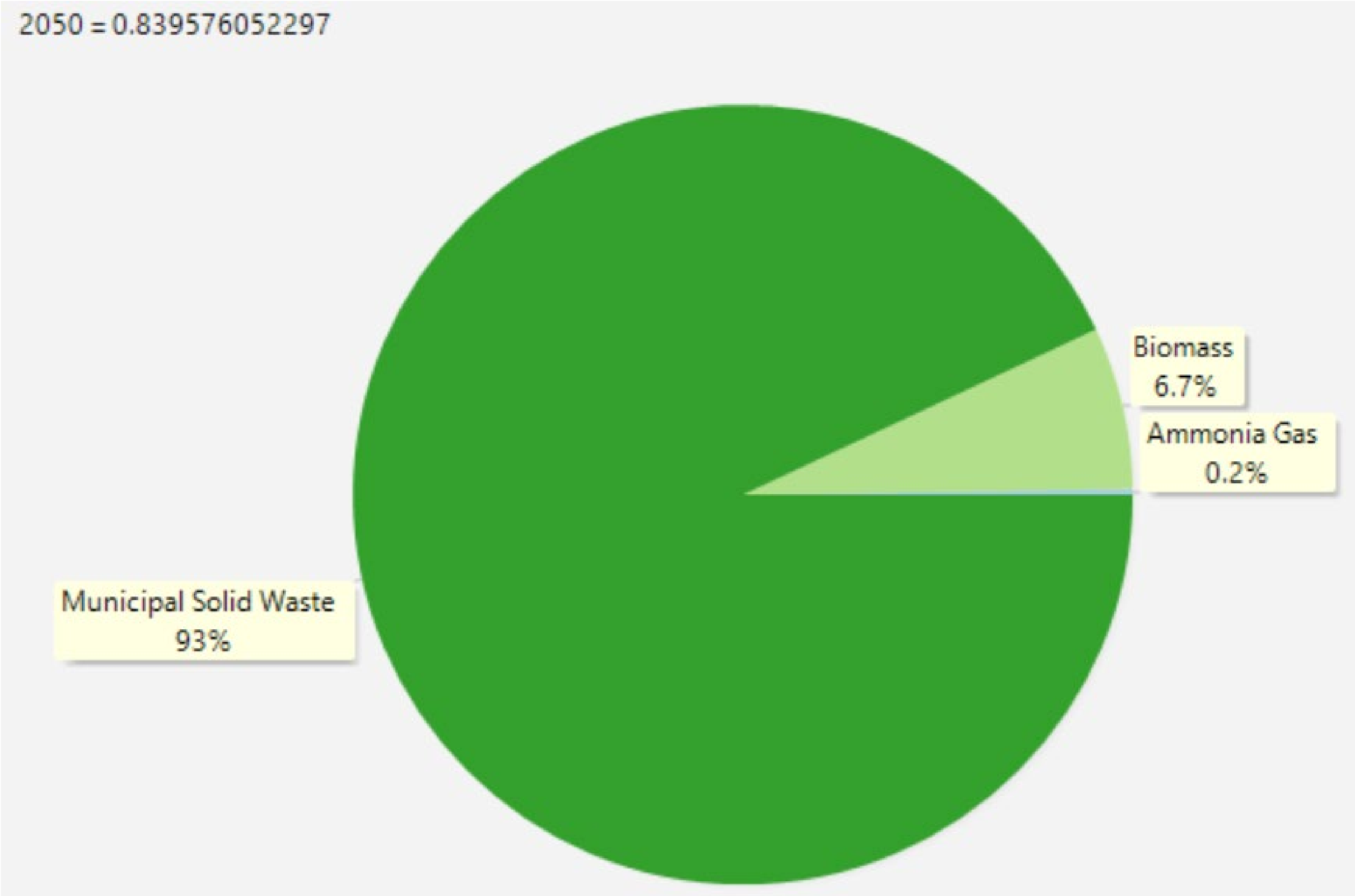


Figure 44: Percentage share of emissions in power sector by feedstock fuel type in 2050 (HA2 Optimised)

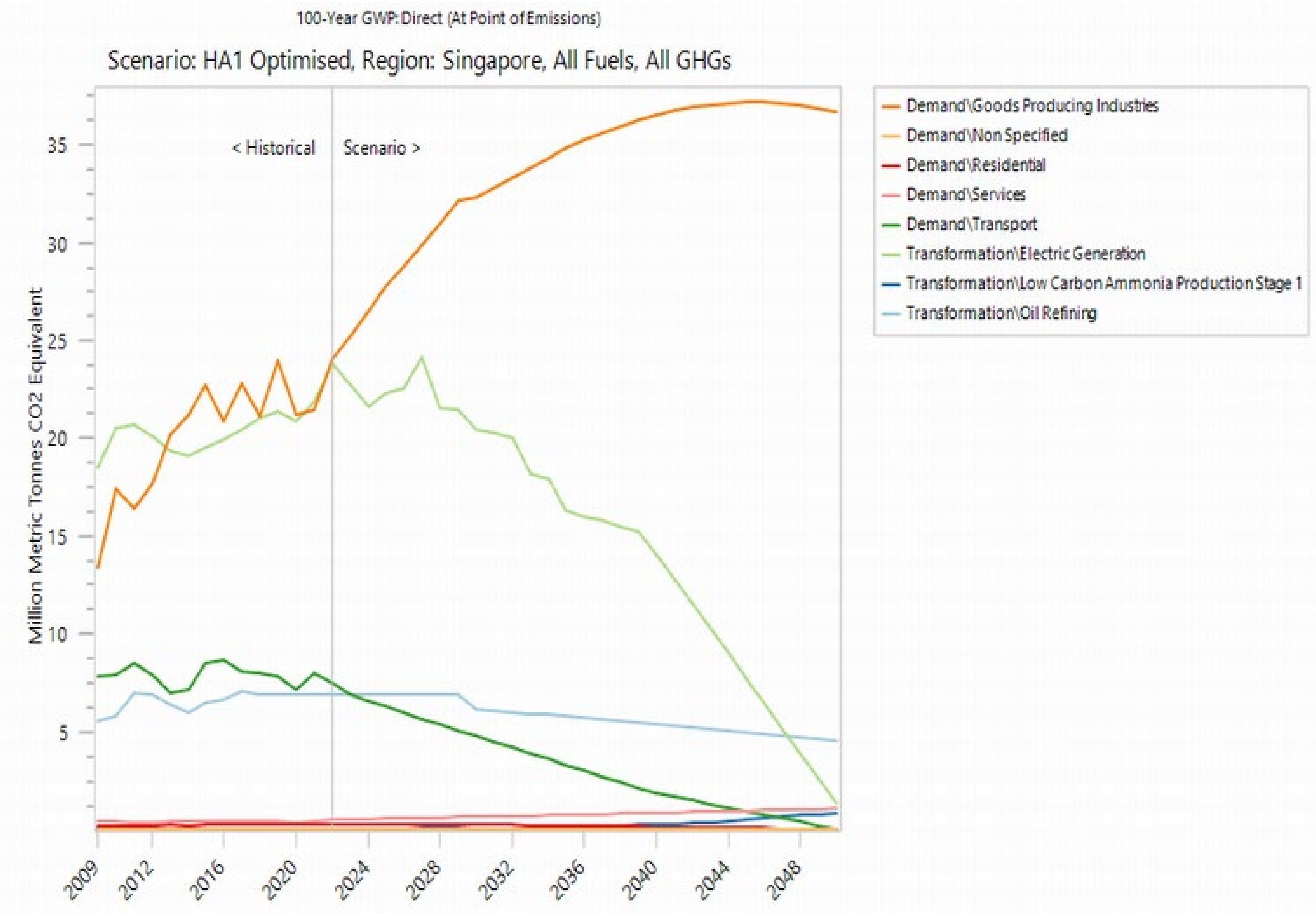


Figure 45: Absolute emissions by domestic energy demand/supply sector (100-Year GWP) (HA1 Optimised)

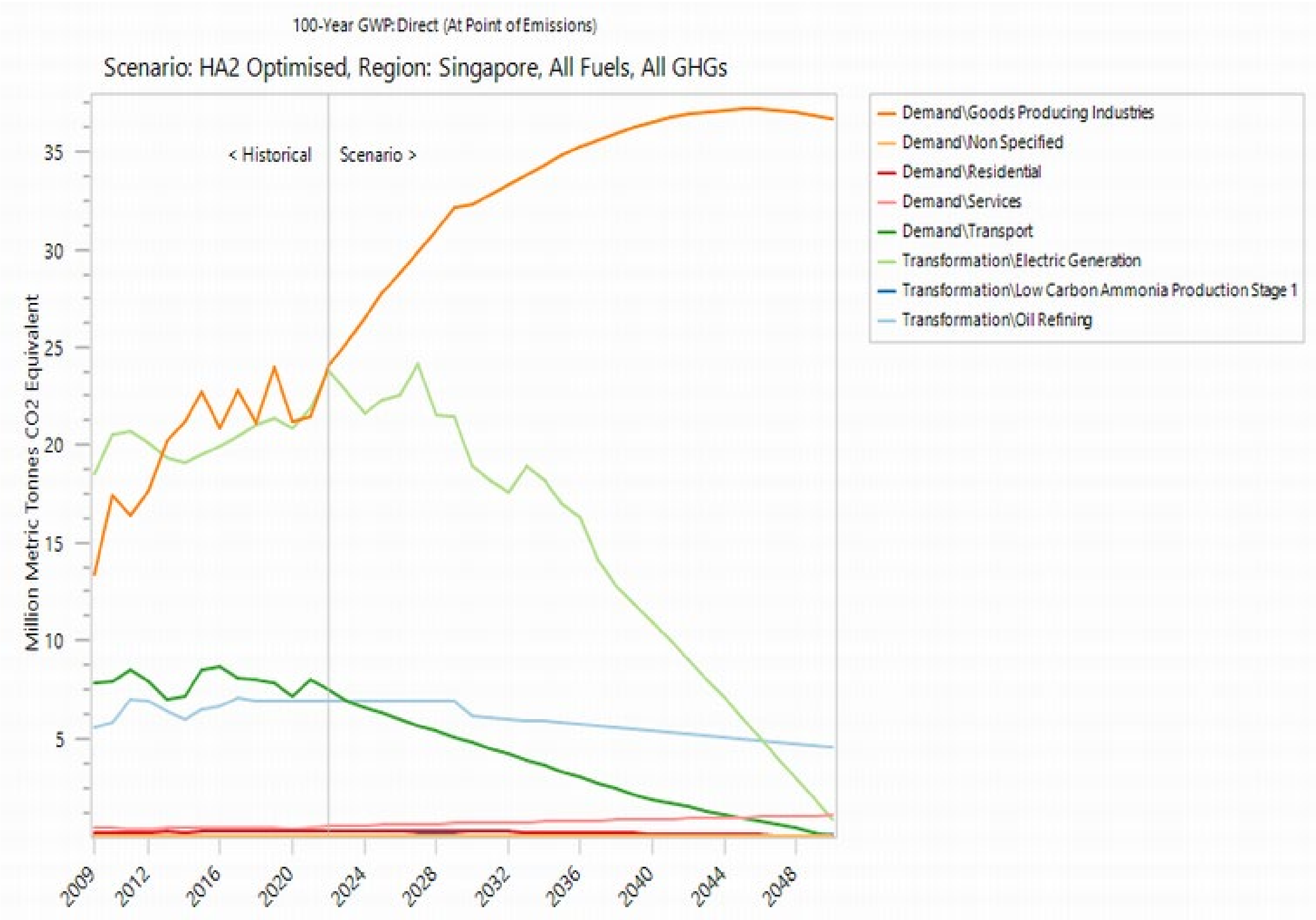


Figure 46: Absolute emissions by domestic energy demand/supply sector (100-Year GWP) (HA2 Optimised)

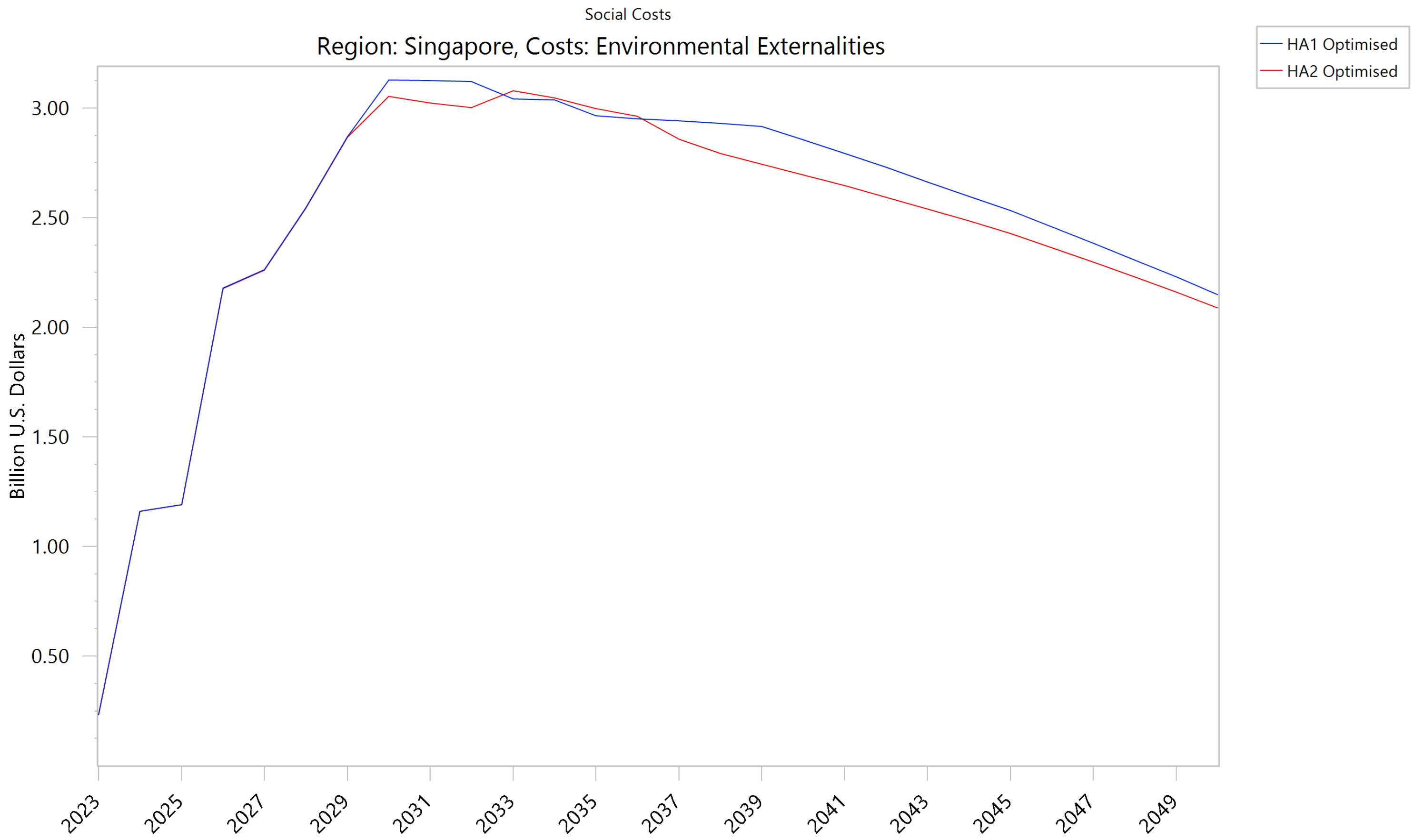


**Figure 47: Cost of environmental externalities (HA1 Optimised and HA2 Optimised)**

In HA1 (Optimised) and HA2 (Optimised), GHG emissions from the power sector are projected to peak at 24.2 $MtCO_2e$ in 2027, reaching 20.5 $MtCO_2e$ and 19 $MtCO_2e$ in 2030 respectively and generally decreasing to 1.4 $MtCO_2e$ and 0.8 $MtCO_2e$ respectively in 2050. Emissions start decreasing consistently after 2027 in HA1 (Optimised) and after 2033 in HA2 (Optimised).

On average, HA1 (Optimised) has higher annual emissions of 1.1 $MtCO_2e$ than HA2 (Optimised) between 2023-2050. From 2023-2050, the rate of average annual decrease in emissions in HA1 (Optimised) is 8.9% compared to 10.1% in HA2 (Optimised).

In 2030, in HA1 (Optimised) and HA2 (Optimised), natural gas OCGT and CCGT constitute majority of the emissions (65.8% and 63% respectively), followed by WTE plants (18.4% and 19.3% respectively), oil-fired power plants (8% and 8.6% respectively), hydrogen power plants (6.3% and 6.4% respectively), coal and biomass cogeneration power plants (1.4% and 2.6% respectively) and low-carbon ammonia power plants (0.00780% and 0.00840% respectively).

In 2050, the remaining emissions in HA1 (Optimised) and HA2 (Optimised) come from the combustion of MSW, low-carbon ammonia and biomass, with WTE plants generating the majority of emissions (1.2 $MtCO_2e$ and 0.8 $MtCO_2e$ respectively).

In the projection period, HA2 (Optimised) can abate a net cumulative total of 31.3 $MtCO_2e$ more emissions compared to HA1 (Optimised). HA2 (Optimised)'s higher overall emissions abatement potential relative to HA1 (Optimised) is attributed to the lower cumulative emissions of natural gas OCGT and CCGT, oil-fired power plants and low-carbon ammonia power plants by 47.4 $MtCO_2e$. This more than offsets the higher amount of cumulative emissions (16.2 $MtCO_2e$) generated by hydrogen power plants, WTE plants and coal and biomass cogeneration plants in HA2 (Optimised) during that period compared to the same power plants in HA1 (Optimised).

In both scenarios, GHG emissions from all domestic sectors are projected to increase to a peak of 67.5 $MtCO_2e$ in 2027.

In HA1 (Optimised), it reaches 64.7 $MtCO_2e$ in 2030 and continue to generally decrease to 44.6 $MtCO_2e$ in 2050, with goods producing industries constituting the majority (82.4%) of overall emissions.

In HA2 (Optimised), it reaches 63.2 $MtCO_2e$ in 2030 and continue to generally decrease to 43.2 $MtCO_2e$ in 2050, with goods producing industries constituting the majority (84.9%) of overall emissions.

This suggests that HA1 (Optimised) and HA2 (Optimised) meet the first part of the previous enhanced NDC target of 65 $MtCO_2e$ by 2030. HA1 (Optimised and HA2 (Optimised) falls short of meeting the second part of the previous enhanced NDC target (33 $MtCO_2e$ by 2050) by 11.6 $MtCO_2e$ and 10.2 $MtCO_2e$ respectively.

Regarding environmental externality costs of $CO_2$ based on the carbon tax trajectory of Singapore, total costs are expected to peak at USD 3.13 billion in HA1 (Optimised) in 2030 and USD 3.08 billion in HA2 (Optimised) in 2033, decreasing to USD 2.15 billion and USD 2.09 billion in 2050 respectively. Between 2023-2050, costs are generally lower in HA2 (Optimised) than in HA1 (Optimised) except in years 2033-2036.

## 9.6 Grid emission factor and emission intensity

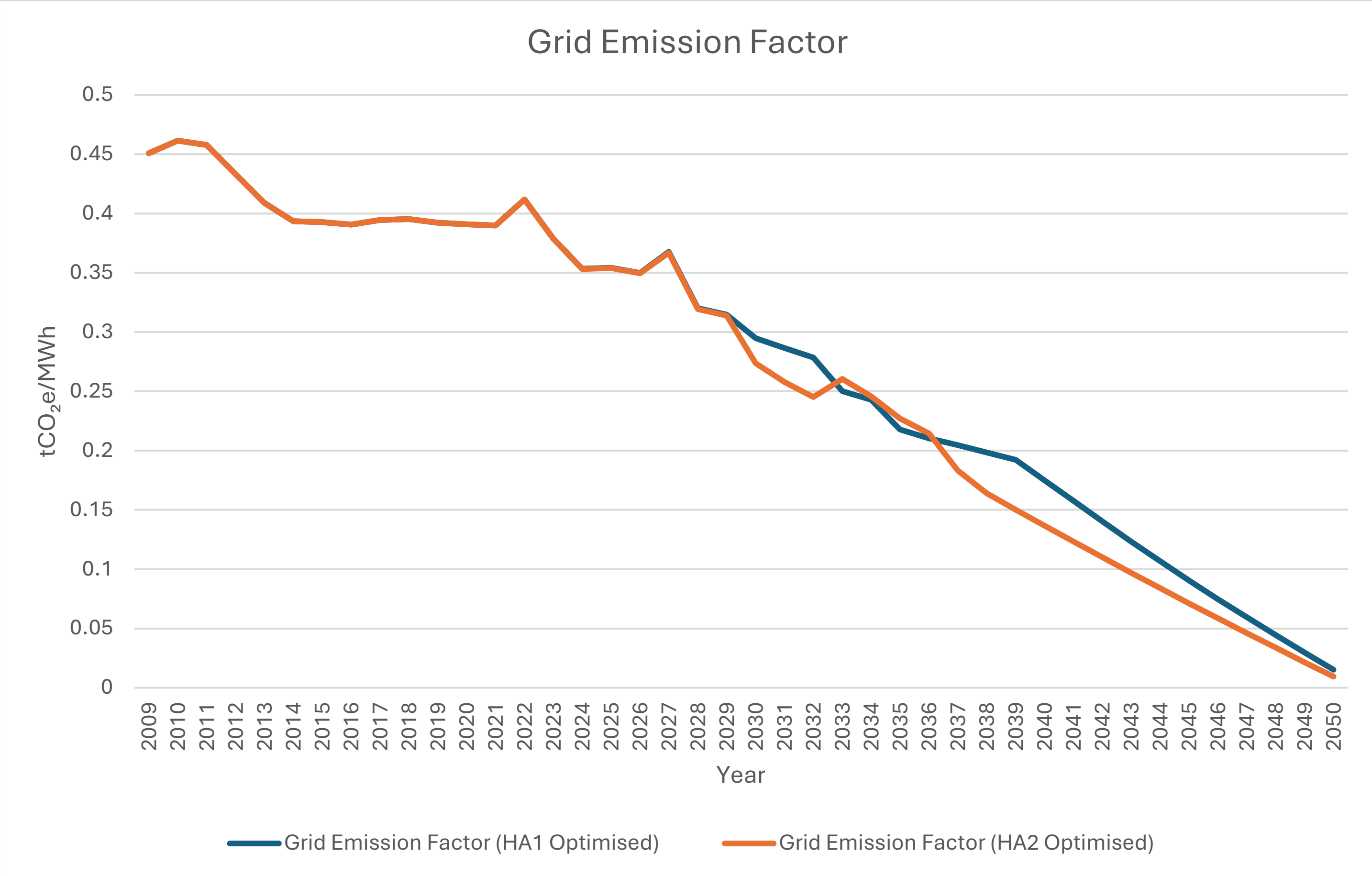


**Figure 48: Grid emission factor (HA1 Optimised and HA2 Optimised)**

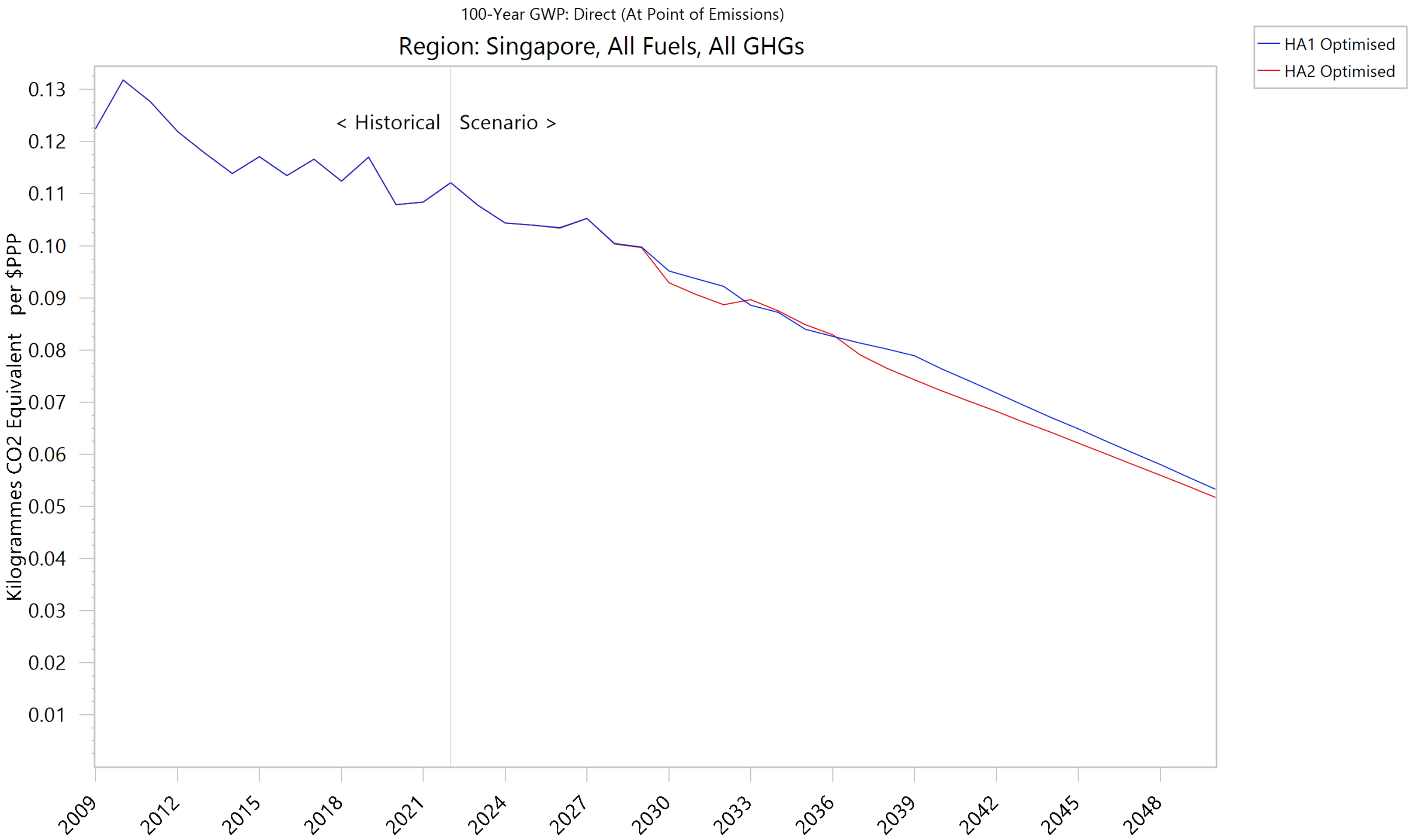


**Figure 49: Emission intensity (HA1 Optimised and HA2 Optimised)**

In HA1 (Optimised), grid emission factor is projected to reduce from 0.379 $tCO_2e/MWh$ in 2023, to 0.295 $tCO_2e/MWh$ in 2030 and to 0.0152 $tCO_2e/MWh$ in 2050. From 2009-2050, grid emission factor would have been reduced by 96.6%.

In HA2 (Optimised), however, grid emission factor is projected to reduce to 0.274 $tCO_2e/MWh$ in 2030 and to 0.00942 $tCO_2e/MWh$ in 2050. From 2009-2050, grid emission factor would have been reduced by 97.9%.

Grid emission factor is generally lower in HA2 (Optimised) compared to HA1 (Optimised) during the projection period except during 2033-2036.

In HA1 (Optimised) and HA2 (Optimised), emission intensity is expected to reduce from 0.108 $kgCO_2e$/\$PPP (at 2007 prices) in 2023 to 0.0951 $kgCO_2e$/\$PPP and 0.0929 $kgCO_2e$/\$PPP in 2030 respectively and to 0.0533 $kgCO_2e$/\$PPP and 0.0518 $kgCO_2e$/\$PPP respectively in 2050. A consistent downward trend starts after 2027 at 0.105 $kgCO_2e$/\$PPP.

Both scenarios can achieve the government's initial 2030 emissions intensity target of 0.113 $kgCO_2e$/S\$GDP at 2010 prices (converted to 0.0976 $kgCO_2e$/\$PPP at 2007 prices[111]) by 2030.

It is also interesting to note that there is only a year-on-year increase in absolute emissions but a year-on-year decrease in emission intensity between 2024-2026 and 2028-2029 in both scenarios. This implies that the rate of net decrease in absolute emissions is greater than the increase in GDP for most of the projected years, meaning there is little compromise between the goal of reducing emissions and maintaining economic competitiveness.

[111] https://data.oecd.org/conversion/purchasing-power-parities-ppp.htm

# 10. IMPLICATIONS AND FUTURE WORK

In sum, our results show:

1. The technical constituents of a renewable energy portfolio that is largely dependent on hydrogen [HA1 and HA2 (Optimised)] as a potential replacement for natural gas and a renewable energy portfolio that is diversified [HA2 and HA1 (Optimised)].

2. In terms of absolute emissions in the power sector:

    a. Our simulation modelling results show that by following the Business-As-Usual (BAU) scenario, Singapore can mitigate emissions in the power sector to 20.6 $MtCO_2e$ by 2030. Based on our two Highly Ambitious (HA1 and HA2) scenarios, emissions in 2030 are lower by 1.1 $MtCO_2e$ and 0.7 $MtCO_2e$ respectively compared to BAU. Moreover, emissions can be further reduced to 0.98 $MtCO_2e$ and 1.15 $MtCO_2e$ respectively by 2050, implying that near net-zero emissions can be achieved in the power sector by 2050 against the backdrop of the policies and assumptions outlined under HA1.

    b. Our optimisation modelling results show that HA1 (Optimised) and HA2 (Optimised) can achieve 20.5 $MtCO_2e$ by 2030 and 19 $MtCO_2e$ in the power sector respectively by 2030. While emissions are reduced to 1.36 $MtCO_2e$ under HA1 (Optimised) in 2050, emissions are reduced to 0.84 $MtCO_2e$ under HA2 (Optimised) in 2050, implying that near net-zero emissions can be achieved in the power sector by 2050 against the backdrop of the policies and assumptions outlined under HA2 (Optimised).

3. In terms of absolute emissions in all domestic sectors, regarding the first part of Singapore's latest revised NDC emissions target by 2030: none of the scenarios modelled are able to achieve it. However, regarding the first part of Singapore's previously enhanced NDC emissions target by 2030, HA1, HA2, HA1 (Optimised) and HA2 (Optimised) can both achieve 65 $MtCO_2e$ and peak emissions by 2030, while BAU can only achieve 65 $MtCO_2e$ but unable to peak emissions by 2030. While being unable to achieve the second part of Singapore's latest revised NDC emissions target i.e., overall net zero emissions by 2050, all the HA scenarios (simulated and optimised) are relatively closer to achieving the second part of the previously enhanced NDC target of 33 $MtCO_2e$ by 2050, missing the mark by around 10.2-11.6 $MtCO_2e$.

4. EMA assessed that hydrogen could meet up to 50% of Singapore's projected electricity demand by 2050, while solar PV and nuclear could meet up to 10% each. HA1 demonstrates how EMA's hydrogen targets can be achieved, while HA2 demonstrates how EMA's nuclear targets can be achieved. HA1 (Optimised) demonstrates how EMA's nuclear and solar PV targets can be achieved, while HA2 (Optimised) demonstrates how EMA's solar PV targets can be achieved.

5. Generally, the utilisation pattern of battery energy storage systems (BESS) aligns with typical daily activity cycles and the solar generation availability profile, indicating a potentially efficient integration of renewable energy sources with storage solutions for Singapore.

Technology plays a pivotal role in shaping the future. Future work could attempt to model more ambitious policies not just for the power sector but also for the other transformation sectors and demand sectors. This is important given that in the projection years, oil products continue to contribute to the bulk of emissions in the demand sectors (about 27.1 $MtCO_2e$ in 2050) which is largely concentrated in the manufacturing industries and oil refining still contributes to about 4.5 $MtCO_2e$ of emissions in 2050 after an ambitious implementation of carbon capture solutions.

Using bottom-up approaches which have greater flexibility in modelling changes in the energy intensities of the industrial and services sectors due to the implementation of industrial and service-oriented energy efficiency policies would allow for more pronounced differences in the projected energy demand and emissions across the various scenarios. For example, not only can hydrogen, hydrogen blend and ammonia be considered as a potential clean fuel in the power sector, but also in the transport and industrial sectors. In addition, due to Singapore's open economy and as a leading commodities' trading hub, it would be prudent to relate energy use and emissions from not only the domestic demand sectors but also from the transboundary sectors i.e., international aviation and shipping.

Within the context of the energy trilemma, where should Singapore focus be? How would this consideration affect how Singapore's net zero carbon pathways, and how it reaches there?

We are of the opinion that Singapore's focus should be on minimising this trilemma, keeping energy security as the priority. Singapore would need to explore feasible options to import cost competitive low-carbon hydrogen, similar to how Singapore is importing its current supply of natural gas. However, global gas supply chain disruptions in the future might see Singapore falling back on standby fossil fuels such as diesel to ensure energy security if the deployment of other clean alternative reserves such as nuclear energy or solar PV are inadequate in meeting energy demand.

Moreover, it is unclear as to how much green hydrogen fuel (created from renewable energy) can be imported relative to blue hydrogen fuel (created from natural gas), and the efficacy of carbon capture solutions to sequester $CO_2$ released from burning blue hydrogen for power generation and industrial processes.

Cross-border renewable energy trade is another attractive solution to reduce reliance on fossil fuels for power generation, especially since governments of neighbouring countries with high potential in indigenous renewable energy production and/or being strategically positioned in the ASEAN region (i.e., Malaysia) have recognised the benefits to the growth of the clean energy industry by becoming a regional renewable energy generation hub. However, risks associated with engineering of undersea cables and high interconnection infrastructure costs may be a setback, as seen in the failed Sun Cable project to import 1.75 GW from Australia. Therefore, adjusting for such uncertainties in the transition would be necessary to flatten Singapore's trajectory in achieving its net zero emissions target.

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