Life Cycle Based Environmental Impacts of Future New Zealand Electricity Supply

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Louise Bullen

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Abstract

Electricity use is an important contributor to the environmental impacts of many products and services in New Zealand. In this research, the life cycle based potential environmental impacts and benefits of future New Zealand low voltage electricity were assessed based on a range of electricity scenarios (for years 2018-2050).

A Life Cycle Assessment (LCA) approach was adopted and Impact Assessment undertaken using twelve environmental indicators. The functional unit was the annual supply of low voltage electricity to New Zealand consumers.

It was found that increasing the proportion of renewable generation in the electricity mix has clear environmental benefits. The greatest benefits are observed in indicators where current impacts are predominantly due to combustion of fossil fuels, in particular the climate change indicators, ADP fossil and PED non-renewable.

A case study of a New Zealand detached house demonstrated that the choice of future electricity scenario can have a significant impact on the magnitude of the life cycle impacts of this particular long-lived product with the carbon footprint varying by up to 24% depending on the electricity scenario used.

Embodied carbon accounted for 5-12% of the total carbon footprint of New Zealand electricity. The contribution of embodied carbon to the carbon footprint increases over time as more renewable generation infrastructure is constructed. Current methods for calculating the carbon footprint of New Zealand electricity for greenhouse gas reporting purposes exclude embodied carbon and utilise different allocation methods than the one used in this study for cogeneration emissions. This results in a carbon footprint that is 37-39% lower than the life cycle-based results calculated in this study.

The carbon footprint of future New Zealand electricity was examined in the context of planetary boundaries. It was found that future scenarios of electricity generation and supply are not compatible with limiting climate change to a 1.5°C increase by 2050 if the electricity sector is considered in isolation. Attributing some of the benefits from electrification of the manufacturing and land transport sectors to the electricity sector can result in a carbon footprint compatible with meeting a 1.5°C climate target based on combined economic and grandfathering sharing principles. Climate targets based on other combinations of sharing principles exceeded a 1.5°C climate target by the early 2020s when 50% of the benefits of electrification of the manufacturing and land transport sectors were attributed to the electricity sector. However, if 100% of the benefits are allocated to the electricity sector, these PBs are exceeded for a period of time (2023-2047) then, the cumulative carbon footprint falls to a level below the PBs from 2048 onwards.

Impacts of new electricity generation infrastructure were fully allocated to the year of construction in this research. This is an appropriate approach in the context of an absolute sustainability assessment such as a comparison with a climate change target where the timing of impacts is relevant. However, it may not be appropriate when undertaking a relative assessment comparing two products or services or when assessing short-lived products due to the potential for the results to be influenced by the timing of impacts associated with the construction of generation infrastructure.

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1 Introduction

1.1 Background

The New Zealand electricity system is an important contributor to the life cycle-based environmental impacts associated with many activities, products and services in New Zealand. Electricity generation in 2018 was composed of 84% renewable generation. The proportion of renewable generation is anticipated to increase in the coming years (MBIE, 2019b) and the New Zealand Government has a target of transitioning to 100% of electricity generation from renewable sources in a normal hydrological year (Ardern, 2017).

In New Zealand, the main sources of renewable generation are hydro power, geothermal and wind and the main non-renewable generation fuels are natural gas and coal. It is commonly assumed that there are no, or minimal, impacts associated with renewable electricity generation, but all forms of electricity involve impacts due to the construction of generation infrastructure. In addition, renewable generation technologies can cause other impacts on the environment. For example, geothermal is a renewable energy source but results in the emission of greenhouse gases (GHGs) from fugitive emissions.

Life Cycle Assessment (LCA) is a methodology that can be used to assess the life cycle impacts of products, services, activities or sectors. LCA can be used to quantify the impacts associated with the full life-cycle of producing, using and disposing of a product or service on a ‘cradle to grave’ basis or, alternatively, a portion of the life-cycle can be considered (e.g. ‘cradle to gate’). The LCA methodology analyses an inventory of all the required inputs and emissions associated with the selected product and quantifies the resulting impacts in terms of a range of environmental impact categories and indicators.

LCA can be combined with a planetary boundary approach to determine the absolute sustainability of a product, service, industry or sector. Planetary boundaries are based on the premise that the planet’s biophysical subsystems or processes have natural limits and operating outside of these limits could have deleterious impacts on human society (Rockström et al., 2009). An absolute sustainability approach seeks to determine the safe operating space in relation to one or more global planetary boundary scaled down to the relevant country, sector or product level.

The nature of electricity generation in New Zealand is expected to change over time as generation demand increases and new generation infrastructure is constructed to meet that demand. This will result in impacts associated with the new infrastructure and changes in the operational impacts of electricity generation as the mix of generation technologies changes. Determining the impacts associated with electricity use in the future, and how they change over time, is an important factor in assessing the life cycle impacts of long-lived products where electricity use is a significant input. Buildings, which typically have a life-span of many decades, are an example of long-lived products for which electricity consumption is an important contributor to life-cycle environmental impacts.

1.2 Research Objectives

The purpose of this research thesis was to investigate the potential environmental impacts of the New Zealand electricity system in the future. It builds upon an earlier Master’s thesis which examined the life-cycle based environmental impacts of the New Zealand electricity system using the 2013 New Zealand electricity grid mix (Saçayon Madrigal, 2015). The current study expands this assessment to consider the future New Zealand electricity system based on supply and demand scenarios out to 2050 developed by the Ministry of Business Innovation and Employment (MBIE) (2019b), and scenarios out to 2035 developed by the Interim Climate Change Committee (ICCC) (2019a).

The research questions addressed in the research are:

1. What is the environmental profile of the future New Zealand electricity grid mix?
2. Will increased renewable electricity generation in New Zealand enable the electricity sector to meet a climate target consistent with limiting global temperature increase to 1.5°C above pre-industrial levels?
3. How should future grid electricity be modelled in New Zealand LCA studies of long-lived products and activities?

2 New Zealand Electricity System

2.1 Overview

New Zealand grid electricity supplied over 40,000 GWh of electricity to residential, commercial and industrial consumers in 2018 (MBIE, 2020a). The electricity system is composed of fuel suppliers, generators, transmission and distribution operators, electricity retailers, consumers and regulators. The following description provides a summary of the main components and participants in the New Zealand electricity system.

2.2 Fuel Supply and Generation

There are five major electricity generating companies in New Zealand: Genesis Energy, Meridian Energy, Mercury, Contact and Trustpower. The first three have a mixed government and private sector ownership model whereas Contact and Trustpower are private sector companies. There are also a number of smaller generators (MBIE, 2019c). The following generation figures are based on MBIE electricity data in 2018 (MBIE, 2020a).

Electricity from natural gas made up 12.5% of electricity generation and 22% of natural gas production was used for electricity generation in 2018 (MBIE, 2020a). New Zealand has no natural gas import or export facilities and therefore natural gas is supplied entirely from domestic resources. All producing natural gas fields are in the Taranaki region and gas is transported to thermal electricity producers via high pressure gas pipelines.

Coal made up 3.4% and oil 0.03% of electricity generation. Coal and oil are both produced locally and also imported to New Zealand. The Genesis Huntly power plant is the only remaining coal fired power plant in New Zealand and is used primarily during periods of peak demand.

Generation from renewable resources accounted for 83.9% of electricity generation in 2018. The proportion of renewables varies from year to year with a general trend since 2009 of an increasing proportion of renewable generation.

The single biggest generation source is hydropower which contributed 60% of electricity generation in 2018. Hydropower has been the biggest source of electricity for many years; accounting for 52-82% of electricity generation since 1974.

Geothermal energy comprised 17.1% of electricity generation. The proportion of geothermal electricity in New Zealand increased significantly between 2007 and 2015 from just under 8% in 2007 to 17.3% in 2015. Since 2015 the proportion of geothermal electricity has remained relatively steady at over 17%. New Zealand is the second biggest generator of geothermal electricity in the OECD after the United States (IEA, 2018).

Wind power accounted for 4.8% of electricity generation in 2018. Wind power has been a relatively recent addition to the New Zealand electricity generation mix accounting for less than 1% of generation prior to 2005. Biogas, solar, wood and waste heat each contributed less than 1% and in total accounted for 1.6% of electricity generation in 2018.

Currently, there are no utility scale solar generation facilities within New Zealand but, in recent years, there has been rapid growth in the use of roof-top solar photovoltaic (PV) generation by business and residential users. In January 2019 there were 22,000 small-scale (less than 10 kW capacity) solar PV installations, of which 21,000 installations were residential, with a total capacity of 80 MW (MBIE, 2019b). There is no direct data held on distributed solar generation;

however, it is estimated that annual generation has increased from 7 GWh in 2013 to 98 GWh in 2018 representing 0.2% of total electricity generation.

2.3 Transmission and Distribution

The transmission system in New Zealand is operated by Transpower, a state-owned enterprise, which owns, operates, maintains, and develops the high voltage electricity transmission network (the national grid). The national grid is composed of a high voltage alternating current (HVAC) transmission network and an interisland high voltage direct current (HVDC) link.

The HVAC network consists of a grid backbone of 220 kV transmission lines stretching nearly the full length of each Island, and a network of 110 kV lines running roughly parallel to the 220 kV system. The 110 kV system is used to supply regions not reached by the 220 kV system and for sub-transmission to substations within a region. The HVDC connects the North and South Island transmission networks and runs between the Benmore substation in the South Island and the Hayward substation in the North Island and includes three 40 km submarine cables across Cook Strait. The HVDC transmission link can operate in either direction. The combined HVAC and HVDC routes cover approximately 11,000 km and include 168 substations (Transpower, 2018a).

The medium and low voltage distribution network in New Zealand is operated by 29 local distribution network companies who provide distribution services from the national grid to consumers (MBIE, 2018). The distribution network companies provide distribution services to electricity retailers who sell electricity to consumers. Some large electricity users purchase directly from electricity generators and several electricity generators also operate electricity retail businesses.

2.4 Regulation of New Zealand Electricity System

The Electricity Authority is the main regulator of the electricity industry in New Zealand and was established under the Electricity Industry Act 2010. It is an independent crown entity responsible for developing and enforcing the Electricity Industry Participation Code, supporting the development of the industry, monitoring the industry and contracting a range of service providers to operate the electricity market and system (Electricity Authority, 2019).

Transpower is contracted by the Electricity Authority to act as the system operator which includes coordinating supply and demand resources in real-time as well as assessing security of supply, helping to coordinate generation and transmission outages, and ensuring new generators meet the Electricity Industry Participation Code 2010 requirements for system reliability (Electricity Authority, 2018).

Several other regulators have roles related to the electricity system. MBIE is responsible for advising the government on energy policy. Local and regional councils have a role in approval of generation, transmission and distribution infrastructure under the Resource Management Act 1991. The Commerce Commission is responsible for approving Transpower proposals for new transmission infrastructure.

2.5 Future Direction of New Zealand Electricity

2.5.1 Government Policy and ICCC Analysis

The New Zealand Government has recently introduced several new policies that affect the future direction of the electricity industry. In November 2017, a target of transitioning to electricity generated from 100% renewables in a normal hydrological year was announced (Ardern, 2017). This was followed in April 2018 by an announcement that there would be no further offshore oil and gas exploration permits issued (Ardern, 2018).

The ICCC was established in April 2018 to provide independent evidence and analysis to the government on agricultural emissions and planning for a transition to 100% renewable electricity by 2035. The ICCC's report on renewable electricity was publicly released in July 2019. The ICCC concluded that 100% renewable electricity generation by 2035 was technically achievable by overbuilding renewable generation capacity to cover 'dry' years when hydropower generation is constrained. They also concluded that this approach would be very costly, particularly for achieving the last few percent of renewable generation, and that this additional cost would act as a disincentive for the conversion of fossil fuel-based process heat and transport to electricity. The ICCC recommended that, rather than prioritising 100% renewable electricity generation, the government prioritise the accelerated electrification of transport and process heat. The ICCC noted that, under a 'business as usual' approach, New Zealand was on track to achieve an average of 93% renewable electricity generation by 2035 due largely to wind and geothermal being the cheapest forms of new electricity generation and expectations of continued decreases in the cost of wind, solar and battery technology. The ICCC estimated that conversion of about 50% of the vehicle fleet to electric vehicles and accelerating conversion of low and medium temperature process heat to electricity relative to current levels could result in net emissions reductions of 5.4 Mt carbon dioxide equivalent (CO_2eq) a year in 2035. A range of recommendations on how accelerated electrification could be achieved were proposed by the ICCC (2019a).

The ICCC conclusions were based on a range of future electricity scenarios out to 2035 and assumptions regarding electricity demand, supply, pricing and GHG emissions associated with the different scenarios. The three main scenarios explored were a 'business as usual' (BAU) scenario, a '100% renewable' scenario and an 'accelerated electrification' scenario which aimed to explore whether accelerated electrification of transport and process heat could achieve larger overall emissions reductions compared to the 100% renewable scenario. The main assumptions for each of the ICCC scenarios are summarised in Appendix B (ICCC, 2019a). The generation mix for each scenario is summarised in Section 5.4.1 and the anticipated new build generation capacity is summarised in Section 5.4.2.

2.5.2 MBIE Demand and Generation Scenarios

MBIE is responsible for modelling potential future electricity demand and generation scenarios (EDGS) which are used to inform the Commerce Commission's assessment of Transpower proposals for future capital expenditure on the national grid. The most recent modelling results were released in July 2019. The scenarios do not constitute predictions of future electricity demand and generation but are intended to represent a range of hypothetical futures. The modelling covers the period from 2018 to 2050. The five scenarios represent a range of different potential future outcomes and are designed to consider the uncertainty of future economic growth, technological progress and policy changes. The five scenarios are described in Box 2.1 and the main assumptions are summarised in Appendix B (MBIE, 2019b).

Figure 2.1 shows the historical stationary energy sector (i.e. non-transport energy) GHG emissions from 1990 to 2017 and projected emissions from 2018 to 2050 under the five MBIE EDGS.

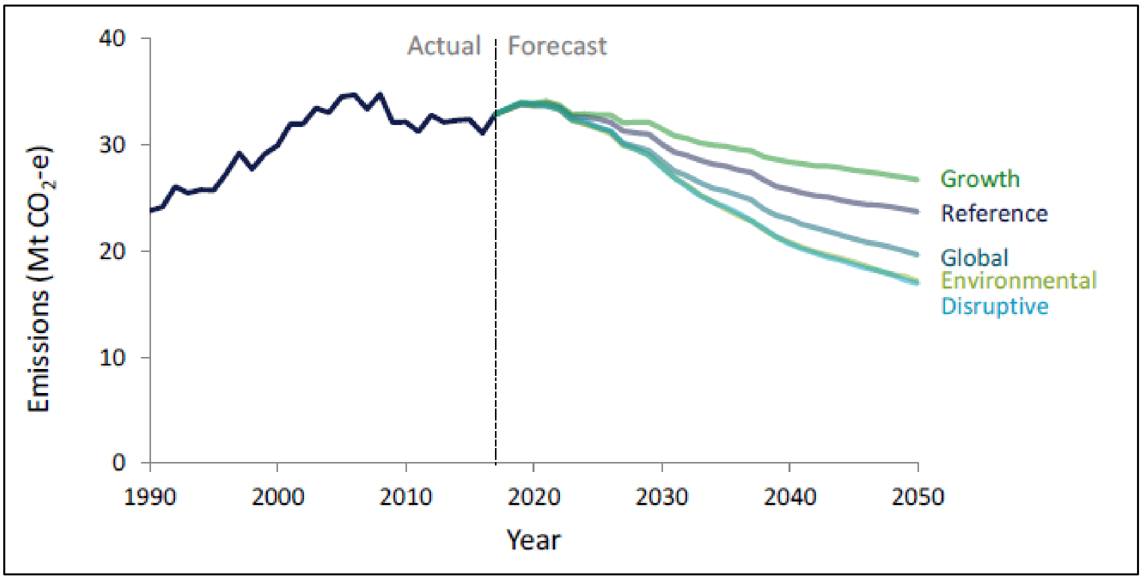

Figure 2.1: Actual and Projected Stationary Energy Sector GHG Emissions 1990-2050
Source: MBIE (2019b)

A summary of the key MBIE EDGS modelling results are provided in Appendix B and further details regarding the generation mix for each scenario is provided in Section 5.4.1 and the anticipated new build generation capacity is summarised in Section 5.4.2. Over the five scenarios, total electricity demand grows between 18% (Global) and 78% (Disruptive). This range of electricity demand growth reflects both different levels of economic growth and the extent of electrification of vehicles and process heat. The proportion of renewable generation exceeds 94% in all five scenarios with the greatest level of renewable generation under the Environmental scenario at 96%. GHG emissions from the energy sector (which includes stationary energy and transport emissions) also reduce under all five scenarios but there is a wide range of reductions from 19% under the Growth scenario to 48% under both the Environmental and Disruptive scenarios. The Environment and Disruptive scenarios result in similar reductions in GHG emissions although in the Disruptive scenario this is based on a higher growth in electricity demand due to the higher levels of electrification of process heat.

New electricity generation infrastructure is required under all five scenarios (see Section 5.4.2). Under the Reference scenario, 55% of the 6,300MW of new electricity generation capacity is from wind power due to the expected continued decrease in the cost of wind technology. The total amount of new generation required under the Growth, Environmental and Disruptive scenarios is greater than under the Reference scenario, but wind generation comprises a smaller proportion. The EDGS modelling indicates that the lower cost of wind generation becomes less important once wind generation reaches a certain proportion of the generation mix due to the intermittent nature of wind generation and the need for more flexible generation sources to reliably cover periods of peak demand. Additional new generation infrastructure is composed of a mix of geothermal, hydro, solar and gas generation with all of the new gas generation operating in a peaking capacity (MBIE, 2019b).

Box 2.1: Summary of Electricity Demand and Generation Scenarios (EDGS)

Reference: Current trends continue

The ’current trends continue’ scenario is one view of how the electricity system could evolve under current policies and technology trends if no major changes occur. This scenario is used as a reference, against which the other scenarios are compared.

Growth: Accelerated economic growth

This scenario assumes that the past decade of slow growth in labour productivity is an aberration rather than the norm. The central theme of this scenario is that higher economic growth drives higher immigration while policy and investment focus on priorities other than the energy sector. The economy is transformed to put emphasis on high technology. The share of the commercial sector is therefore larger than projected in the Reference scenario. In this scenario, higher income growth leads to higher uptake of electric vehicles. This scenario provides an assessment of what level electricity demand could reach if the economy is doing well.

Global: International economic changes

The central theme of this scenario is that New Zealand’s economy is battered by international trends, leaving little room for local growth or innovation. Some aspects of this scenario are opposite to the accelerated economic growth scenario such as the uptake of EVs. In this scenario, higher cost for wind turbines and solar power than in the Reference scenario is also explored.

Environmental: Sustainable transition

In this scenario, the government targets more ambitious emissions reduction levels than in the Reference scenario. Strong environmental leadership driven by regulation and incentives (rather than technology) provides the platform for the achievement of this policy target. Policies are introduced to support the electrification of both transport and process heat. This scenario is intended to provide a sense of what settings are required for decarbonising the economy and helps understand the relationship between the reduction of emissions and its associated costs.

Disruptive: Improved technologies are developed

The pace of future uptake of EVs and solar PV, and the future level of electrification in process heat are highly uncertain. In this scenario, electricity demand and supply implications of more advanced and sophisticated technological progress in the energy sector are assessed. This in turn leads to a faster reduction in technology costs and higher uptake of both EVs and solar than the Reference scenario. The extent of the electrification of process heat is even greater than in the Environmental scenario. The central theme of this scenario is that new and improved technologies enable rapid electrification of both transport and process heat. Emerging technologies which may be influential in the future are not incorporated in the model. Instead this scenario focuses solely on the increased uptake of EVs, solar PV, and electrification of process heat.

Source: MBIE (2019b)

2.5.3 Transpower Te Mauri Hiko Scenarios

Transpower have also investigated potential future electricity generation and supply scenarios which were reported in a white paper in 2018 (Transpower, 2018d) and recently updated (Transpower, 2020). The base case scenario presented in this assessment reflects a future where vigorous coordinated efforts to reduce emissions are undertaken, there is widespread adoption of currently available technologies such as electric vehicles, electrification of transport and industrial heat are key contributors to mitigation of GHG emissions, there is a continuation of current trends in generation and energy storage, and coal and gas generation is fully retired by 2040.

Alternative scenarios, in terms of both the demand and supply, are also explored which represent a range of possible paths in terms of climate change outcomes, global and domestic climate change responses, technological development and adoption, economic factors and the resulting electricity supply mix. It is noted that these different scenarios do not result in qualitative differences in New Zealand's energy future but differ mainly in the magnitude and speed of demand growth and in the mix of generation types used to supply growth in demand (Transpower, 2018d).

2.5.4 Summary of Future Electricity Scenarios

Future electricity scenarios represent a range of possible future realities and reflect both the difficulty of predicting future outcomes and the complex range of factors that influence both electricity supply and demand. The future electricity scenarios presented by the ICCC (2019a), MBIE (2019b) and Transpower (2018d) reflect a variety of views of possible future outcomes but also some common themes.

All the scenarios described above assume an increasing demand for electricity over time. The rate and extent of that increase is primarily affected by assumptions regarding economic and population growth, and the extent to which transport and industry sectors transition to electricity from fossil fuels. Another key theme common to all scenarios is an increase in renewable generation, particularly wind and solar generation. Associated with the increase in renewables is an expectation of increased distributed generation, particularly solar generation, although the rate of distributed solar generation uptake differs between scenarios.

The differences between the scenarios are largely around the rate and extent of these changes and the future role of fossil fuels within the generation mix. For example, the Transpower base case scenarios assume the retirement of all coal and gas generation capacity by 2040 whereas all the MBIE scenarios retain some gas and coal generation through to 2050. All ICCC scenarios assume the complete retirement of coal by 2035 with the 100% renewable scenario also retiring all gas generation by 2035.

All scenarios identify an ongoing need to provide a generation mix which can meet times of peak demand particularly during the winter months. Fossil fuels currently provide an important peak generation role in the New Zealand generation mix. In scenarios with no or low levels of fossil fuel generation, this peaking capacity is filled by a combination of demand response technologies, battery storage, overbuilding of renewable generation, the use of hydro generation in a peaking capacity or alternatively can result in disruptions to supply.

3 Environmental Impacts of Electricity Systems

3.1 New Zealand Electricity System Studies

Several previous studies have considered the life-cycle environmental impacts of the New Zealand electricity system. This section provides a brief overview of the studies undertaken, the methods adopted and the key findings. Some of the studies reviewed have considered a range of environmental impacts categories but a larger number have specifically focussed on carbon footprint.

A cradle-to-grave LCA study of New Zealand grid electricity was undertaken by Saçayon Madrigal (2015) based on the 2013 electricity grid mix. This study assessed the life cycle impacts of 1kWh of low voltage grid electricity for 12 impact categories using the CML 2001-Apr.2013 impact assessment methodology. Life cycle stages included were manufacture and construction of the power plants, production and supply of fuels, infrastructure and operation of the transmission and distribution network, operation of power plants, decommissioning and waste disposal. It was concluded that fossil fuel generation was the main contributor to most of the environmental impact categories. Electricity produced from coal contributed more than 70% of the total results for the categories of Eutrophication Potential (EP), Freshwater Aquatic Ecotoxicity Potential (FAETP) and Marine Aquatic Ecotoxicity Potential (MAETP); between 50 and 69% of the total results for Abiotic Depletion Potential (ADP); and between 30 and 49% of the total results for Acidification Potential (AP), Human Toxicity Potential (HTP) and Photochemical Ozone Creation Potential (POCP). Other significant sources of environmental impacts were the transmission and distribution network in terms of contributions to ADP Fossil, HTP and Terrestrial Ecotoxicity Potential (TETP). Electricity produced from geothermal was a significant contributor to the AP and TETP indicators. The global warming potential (GWP) of 1 kWh low-voltage electricity was 186 gCO_{2eq}/kWh (Saçayon Madrigal, 2015).

The impact of different time scales was also investigated by undertaking a scenario analysis of the different grid mixes between 1990 to 2014. It was observed that the results were quite variable over time with the most notable variation due to the proportion of coal within the grid mix (Saçayon Madrigal, 2015).

The results of the Saçayon Madrigal (2015) study have been used by BRANZ Ltd (BRANZ) in the 'New Zealand Whole Building Whole of Life Framework' (BRANZ, 2019b) to develop a grid electricity dataset based on the 2016 EDGS (MBIE, 2016). This data is used to assess the environmental impacts of electricity use in buildings using the BRANZ LCAQuick tool (BRANZ, 2019a). Electricity is a significant contributor to the life cycle impacts of buildings and changes in the environmental impacts of electricity over time are an important factor in determining the impacts of a building over its lifetime.

An earlier study of the carbon footprint of New Zealand electricity also followed a cradle to grave approach consistent with the International Reference Life Cycle Data System (ILCD) at an 'entry level' for data quality. This study found a much higher carbon footprint for 1 kWh of low voltage electricity of 360 gCO_{2eq}/kWh based on 2008 generation. It was noted that this was likely to represent a worst case scenario due to conservative assumptions of gas power plant efficiencies and the 2008 grid mix comprising a relatively high proportion of fossil fuel generation (Coelho, 2011).

Barber (2011) calculated GHG emission factors for New Zealand electricity for a range of years between 1991 and 2010. Life cycle emissions were calculated which included upstream emissions of fossil fuel mining, processing and distribution as well as power plant combustion emissions but did not account for emissions associated with renewable sources, infrastructure emissions, geothermal fugitive emissions, or emissions associated with electricity transmission and distribution. The emission factors calculated ranged from 169.1 gCO_{2eq}/kWh in 1991 to 256.8 gCO_{2eq}/kWh in 2005.

Carbon Emissions Pinch Analysis (CEPA) and Energy Return on Investment (EROI) were used to demonstrate that it is possible for New Zealand to meet a 74% increase in electricity demand between 2011 and 2050 while maintaining renewable generation above 90%, and GHG emission targets at 1990 levels. To achieve this it was concluded that wind would need to increase to 27%, geothermal to 25% and hydro to 41% of the electricity grid mix (M. Walmsley, Walmsley, Atkins, Kamp, & Neale, 2014).

A study investigating the time-varying carbon intensity of the New Zealand electricity system based on half hourly generation and demand data and GHG emissions was undertaken based on 2015 data. The GHG calculation method only took account of fossil fuel combustion emissions and did not account for other life-cycle emissions. The results of this study indicated that GHG emissions arose predominantly from base and intermediate demand rather than from peak demand as is observed in many other countries. Peak demand was predominantly met by hydropower during almost all of 2015. The results also indicated that although the winter months had the highest demand, autumn had the highest GHG emissions and carbon intensity due to reduced hydro generation capacity during the drier autumn months (Khan, Jack, & Stephenson, 2018).

M. Walmsley, Walmsley, and Atkins (2018) investigated GHG emissions from the New Zealand electricity system over time due to new construction by relating life cycle GHG emissions footprints to EROI analyses. Four scenarios to 2050 were investigated with three of the scenarios based on MBIE 2016 EDGS and a fourth scenario (High Solar) representing a high level of solar generation. GHG emissions from construction of power plants were fully allocated to the year of construction rather than being spread over the expected lifetime of the plant to better reflect the timing of GHG emissions associated with construction. The study concluded that an emissions peak occurs due to new construction, mainly because of renewable generation, especially solar, and the high energy emissions factors in countries manufacturing generation equipment. The High Solar scenario showed both the greatest reduction in total GHG emissions and the greatest contribution from construction emissions. Under this scenario, there was a peak in construction emissions particularly between 2034 and 2050 with construction emissions contributing 16.8% on average, but in some years over 50%, to total annual emissions.

3.2 New Zealand Studies of Specific Generation Technologies

Life cycle approaches have also been used to assess the carbon footprint and embodied energy of individual electricity generation technologies in New Zealand. A brief summary of these studies is provided below and a summary of the findings in provided in Table 3.1.

Rule, Worth, and Boyle (2009) investigated the carbon dioxide (CO_2) emissions and embodied energy associated with four renewable electricity generation technologies in New Zealand based on case studies of actual or proposed geothermal, large-scale hydropower, tidal (proposed scheme) and wind generation facilities using an LCA approach. The system boundaries included construction, maintenance and decommissioning of infrastructure but excluded the embodied energy of raw materials, geothermal fugitive emissions, biogenic emissions from hydro reservoirs and infrastructure common to all four generation technologies.

Fernando (2010) undertook an embodied energy analysis of five different electricity power plants representing five different generation technologies (natural gas combined cycle, natural gas open cycle, wind, reservoir hydro and run of river hydro) using a combination of process chain analysis and input output analysis. This analysis found that plant construction contributed most of the life-cycle embodied energy for renewable generation technologies while the input of plant fuel contributed the largest amount of embodied energy for the two natural gas plants.

The previous embedded energy (Fernando, 2010) and emissions (Rule et al., 2009) analyses described above were used as a basis to calculate Energy Return on Carbon Emissions (EROC) for wind farms in New Zealand. The average EROC value calculated was 477 GJ/t CO_{2eq} (T. Walmsley, Walmsley, & Atkins, 2017).

McLean and Richardson (2019) calculated GHG emissions from New Zealand geothermal fields based on actual measured emissions factors for CO_2 and methane (CH_4) emissions. It was noted that emissions from natural geothermal surface features far outweighed the emissions from geothermal power stations and that a decline in emissions intensity over time due to degassing has been shown at several New Zealand geothermal fields.

Table 3.1: Carbon Footprint and Embodied Energy Results from Studies of New Zealand Electricity

Generation Type	CO_2 Emissions (Rule et al 2009)	CO_2 & CH_4 Emissions (McLean & Richardson (2019)	Embodied Energy (Rule et al 2009)	Life Cycle Energy Cost (Fernando 2010)
Unit	g CO_2/kWh	g CO_{2eq}/kWh	kJ/kWh	kJ/kWh
Hydropower	4.6	-	55.0	58 (reservoir) 51 (run of river)
Geothermal	5.3	61 (mean) 21-341 (range)	94.6	-
Wind	3.0	-	70.2	170
Tidal	1.8	-	42.3	-
Natural Gas	-	-	-	7,390 (combined cycle) 10,100 (open cycle)

3.3 Life Cycle Studies of Electricity in Other Countries

3.3.1 Overview

Many recent LCA studies have been undertaken in a variety of countries seeking to identify the main sources of GHG emissions associated with electricity and to identify future pathways to achieve a reduction in emissions while providing for increased demand for electricity. The potential for burden shifting in a transition to a higher proportion of renewable electricity sources is also a focus of many studies.

The New Zealand electricity system differs from many other countries due to the high level of renewable electricity sources and relatively low contribution of coal to electricity generation. New Zealand also has no import or export of electricity unlike many continental countries where cross-boundary trade in electricity is common.

Despite these differences, it is useful to identify some common themes from research undertaken in other countries and to understand the determining factors to identify where outcomes or conclusions may be similar or different in the New Zealand context. The following sections provide a summary of some of the key themes and findings of LCA based studies undertaken in countries other than New Zealand.

3.3.2 Fossil Fuels

3.3.2.1 Coal

Many LCA studies have identified coal as the main contributor to adverse environmental impacts associated with electricity generation particularly in terms of climate change. An LCA of electricity production in Portugal indicated that coal had the highest contribution per kWh to GWP, ADP, and EP (Garcia, Marques, & Freire, 2014). Similarly, an LCA of current and future electricity production in the Czech Republic and Poland showed that solid fuels (hard coal and lignite) had the greatest impact in the impact categories of GWP, HTP, particulate matter formation (PMF) and fossil fuel depletion (Burchart-Korol, Pustejovska, Jursova, Blaut, & Korol, 2018).

Several LCA studies have compared the impacts of coal for electricity generation with and without the use of carbon capture and sequestration (CCS) technologies. CCS technology seeks to reduce emissions to the environment associated with the combustion of fossil fuels by capturing the emissions and reinjecting them deep underground. Several studies have shown that the use of CCS technology can reduce some adverse effects associated with coal usage, particularly GWP; however, the use of CCS can also result in increases in other impact categories due to the reduced efficiency of power plants utilising CCS technology and a consequently greater amount of raw material consumed per unit of electricity produced. A study using a hybrid LCA model covering nine different world regions concluded that the use of modern coal power plants with CCS could result in GHG emissions being reduced to 22-26% of emissions from existing coal power plants without CCS. When modern plants with and without CCS were compared, the impacts with CCS increased by 20-60% for almost all impact categories other than GWP (Gibon, Arvesen, & Hertwich, 2017).

The use of flue gas treatment systems in coal powerplants can also result in changes in the relative importance of different impact categories. In Portugal, the introduction of flue gas treatment systems resulted in a decrease in the impact categories of photochemical oxidation (PO) (74% reduction), AP (67% reduction) and EP (2% reduction) between 2008 and 2012 but increases in the impact categories of non-renewable fossil energy demand (nREn), ADP and GWP as a result of the decrease in the power plant efficiency and an increase in ozone layer depletion potential (ODP) (23.5% increase) due to the production of ammonia used in the denitrification system (Garcia et al., 2014).

3.3.2.2 Natural Gas

A consistent finding of comparative LCA studies of different fuel types is that natural gas used for electricity production has a lower life-cycle GWP burden than other fossil fuels (i.e. coal and oil) due primarily to the lower GHG emissions associated with combustion of gas (Farquharson et al., 2017; Gaete-Morales, Gallego-Schmid, Stamford, & Azapagic, 2018; Garcia et al., 2014; Gibon et al., 2017; Orfanos, Mitzelos, Sagani, & Dedoussis, 2019). For example, Garcia et al. (2014) found that electricity produced from gas resulted in a GWP of 370-588 gCO_{2eq}/kWh compared to 988-1021 gCO_{2eq}/kWh for coal and 912 gCO_{2eq}/kWh for oil. Some studies have identified gas as a potential replacement for coal fired electricity in order to meet national GHG emission reduction targets in countries with a high proportion of electricity production currently based on coal (Gaete-Morales et al., 2018; Garcia et al., 2014).

Compared to most renewable electricity sources, natural gas tends to have higher impacts in a number of impact categories including GWP, AP due to NO_x emissions (Gibon et al., 2017), ADP (Gaete-Morales et al., 2018) and ODP. For the latter, in some cases this is due to the use of ozone depleting substance as fire suppressants in the transport of natural gas by pipeline (Garcia et al., 2014; Orfanos et al., 2019).

The relative environmental performance of gas compared to other fossil and renewable fuels is influenced by several factors including the level of CH_4 leakage, type of power plant and the resulting thermal efficiency, and the use of CCS. These factors are discussed further below.

The carbon footprint of gas used for electricity production can be strongly influenced by the percentage of methane leakage during gas exploration, production and transmission. Farquharson et al. (2017) investigated the GHG emissions of modern coal and gas fuelled power plants both with and without CCS using a range of climate metrics including GWP, global temperature change potential (GTP), technology warming potential, cumulative radiative forcing as well as the Model for the Assessment of Greenhouse-gas Induced Climate Change. The results indicated that a natural gas combined cycle plant had lower climate impacts over 100 years compared to a pulverized coal plant, even if the life cycle CH_4 leakage rate for natural gas reached 5%. Over shorter time frames (i.e. 20 years), plants using natural gas with a 4% leakage rate had similar climate impacts as those using coal but were no worse than coal. If CCS was used for both types of power plants, natural gas had lower climate impacts than the coal plant but only for a methane leakage rate below 2%. Some researchers have noted the difficulty of determining the significance of CH_4 leakage rates on environmental impacts due to the lack of empirical measurements of CH_4 leakage rates (Gibon et al., 2017; O'Donoughue, Heath, Dolan, & Vorum, 2014).

The type of power plant and technology used can also be a significant contributor to the impacts of natural gas electricity production. A study considering the GHG emissions of electricity generated from conventionally produced natural gas undertook a harmonisation process of 42 LCA studies with a focus on comparing natural gas-fired combustion turbine (NGCT) and combined-cycle (NGCC) systems. Following harmonisation, a consolidated interquartile range of 420-480 gCO_{2eq}/kWh for NGCC and 570-750 gCO_{2eq}/kWh for NGCT was obtained, with medians of 450 and 670 gCO_{2eq}/kWh respectively. Differences in the thermal efficiency of the two types of plant was identified as the main contributor to the differences in GHG emissions (O'Donoughue et al., 2014).

The use of CCS can reduce the GHG emissions associated with natural gas but can also result in increases in other impact categories due to reduced efficiency. Gibon et al. (2017) found that the use of CCS reduced GHG emissions from NGCC by 50–60% but increased the impacts in all other impact categories by 20–80%.

3.3.2.3 Oil

LCA studies which consider the impacts of electricity produced from oil are less common than those investigating coal, natural gas or renewable technologies. In Portugal fuel oil power plants had higher impacts per kWh in AP, PO and nREn compared to other fossil and renewable electricity generation technologies (Garcia et al., 2014).

3.3.3 Renewable Energy Systems

3.3.3.1 Hydropower

LCA studies which have considered hydropower electricity generation consistently indicate that hydropower has some of the lowest impacts of all generation types in most impact categories except land use and water use. An LCA of electricity generation in Chile considered 11 impact categories based on 2014 data and concluded that hydropower was the best generation technology in all categories with run-of-river being slightly better than reservoir hydro (Gaete-Morales et al., 2018). Kabayo, Marques, Garcia, and Freire (2019) used LCA to consider the environmental impacts of different electricity generation technologies in Portugal, combined with an assessment of socioeconomic impacts, and concluded that small hydro (modelled as a run-of-river system) was the most environmentally and socially sustainable system compared to coal, natural gas, large hydro, wind and solar systems (Kabayo et al., 2019).

Some potential impacts associated with hydropower are not well captured within the LCA methodology but can be important at a local or national level. The flooding of land due to reservoir dams can result in the loss of ecologically important habitat and impacts on local communities can occur due to disruption of pre-existing economic and social uses. The loss of productive or ecologically important land is generally less significant with run-of-river systems. Public opposition to new hydropower projects has been noted by researchers in several countries including Chile (Gaete-Morales et al., 2018) and the USA (Song, Gardner, Klein, Souza, & Mo, 2018).

The role of biogenic CH_4 and other GHGs emitted from hydropower reservoirs is not always considered within LCA studies but is increasingly being recognised as an important source of GHG emissions associated with hydropower generation. GHGs emitted to the atmosphere from hydropower reservoirs are produced from the aerobic and anaerobic decomposition of organic material following flooding of the reservoir. These emissions can be discharged to the atmosphere from the surface of the reservoir as diffusion of CO_2, CH_4 and nitrous oxide (N_2O) or as small bubbles (ebullition) of CH_4. GHGs can also be discharged to atmosphere from the powerplant itself as the water passes through spillways and turbines, due to drawdown of the water level within the reservoir, and downstream of the dam as diffusion or bubbling (Deemer et al., 2016; Song et al., 2018).

Li and Zhang (2014) estimated the global average emissions from hydropower to be 92 gCO_2/kWh and 5.7 gCH_4/kWh which is equivalent to 285 gCO_{2eq}/kWh for hydroelectricity and translates to global GHG emissions of 301.3 Tg CO_2/year and 18.7 Tg CH_4/year due to hydroelectricity dams although they noted the uncertainties associated with these estimates were large. Deemer et al. (2016) estimated that global CH_4, CO_2, and N_2O emissions from reservoir water surfaces (including hydroelectric and nonhydroelectric reservoirs) contribute 800 Tg CO_{2eq} per year over a 100-year time span or approximately 1.5% of the global anthropogenic CO_{2eq} emissions from CO_2, CH_4, and N_2O.

GHG emissions from reservoirs in tropical climates are generally reported to be higher than those from temperate or alpine areas due to high organic matter content, high water and sediment temperature, and an anoxic bottom layer which all contribute to higher levels of GHG production (Demarty & Bastien, 2011). A comparison of the total emissions from hydroelectric projects in tropical regions with thermal power plant equivalents on a short-term basis (not integrated over 100 years) found that six of the twelve sites had total emissions higher than equivalent natural-gas-fired thermal power plants although the authors noted that conclusions reached for a small, non-representative sample of reservoirs cannot be extrapolated to all warm-latitude reservoirs (Demarty & Bastien, 2011).

The difficulty of determining realistic life cycle inventory figures for biogenic emissions from hydropower reservoirs is one of the reasons for the absence of these emissions in many LCA studies. Biogenic emissions can vary depending on many factors including location of the reservoir, amount and type of vegetation present prior to flooding, size and depth of the reservoir, type of dam and depth of water withdrawal. This variability together with the difficulties of obtaining accurate measurements of biogenic GHG emission rates mean that biogenic methane emission in many LCA studies are either ignored or based on generic estimates which may not reflect the reservoir(s) being studied.

3.3.3.2 Geothermal

Bayer, Rybach, Blum, and Brauchler (2013) identified a range of potential direct environmental impacts associated with geothermal electricity production including land use, geological hazards, waste heat, atmospheric emissions, solid waste, emissions to soil and water, water use and consumption, impacts on biodiversity, noise and social impacts. The authors also noted the impacts associated with geothermal energy are very site specific and strongly influenced by the generation technology, reservoir characteristics, receiving environment and the evolution of geothermal technology which makes it difficult to provide a generalised assessment of the impacts of geothermal generation.

A recent review of LCA studies of geothermal energy concluded that impacts are mainly determined by reservoir characteristics, geothermal fluid chemistry, power generation technology, type of emissions and data availability. Most studies reviewed considered GWP impacts and it was concluded that fuel consumption during construction and operation were the primary contributors to this impact category. However, the authors noted that there was still debate in relation to the inclusion of fugitive emissions as part of the system boundaries in LCA studies as they would naturally occur even without the installation of the geothermal power plant (Tomasini-Montenegro, Santoyo-Castelazo, Gujba, Romero, & Santoyo, 2017).

In contrast, Bayer et al. (2013) undertook a literature review of existing LCA studies of geothermal power generation and concluded that operational emissions (particularly fugitive GHG emissions) are an important contributor to environmental impacts associated with geothermal generation and are often underrated. They reported a wide range of operational atmospheric emissions from geothermal plants with 4-740 gCO_2/kWh and 0.75-0.85 gCH_4/kWh in the studies reviewed.

3.3.3.3 Wind

Wind power in OECD countries increased from 3.8 TWh in 1990 to 696.9 TWh in 2017 representing an average annual growth rate of 21.2% and the second fastest growth rate of renewable electricity in the OECD after solar PV (IEA, 2018).

LCA studies of wind generation systems consistently conclude that the primary impacts associated with wind generation occur during the material fabrication and construction stages with minimal impacts during operation (Gaete-Morales et al., 2018; Kabayo et al., 2019; Orfanos et al., 2019). Metal depletion (MD) is one impact category in which wind generation generally scores poorly due to the metal required for wind turbine blades. Gibon et al. (2017) reported that wind power resulted in life-cycle impacts one to two orders of magnitude lower than coal power in eight out of nine impact categories, the exception being MD. Production of wind turbine components contributed 70–90% to all impact indicators for onshore wind systems but less than 20%-50% for offshore systems. Installation, operation and decommissioning activities as well as electrical connections contributed a greater proportion of impacts for offshore systems compared to onshore systems.

In comparing the life cycle impacts of electricity generation technologies in Portugal, Kabayo et al. (2019) found wind generation had the highest MD impact of the six generation methods compared but generally low impacts in the other ten impact categories. Similar results were obtained for an LCA study of electricity generation technologies in Sri Lanka with wind generation resulting in the highest impacts in the MD category (Danthurebandara & Rajapaksha, 2019).

Impacts associated with the decommissioning stage of wind generation have been shown to be highly dependent on the proportion of recycling that is achieved. High levels of recycling were assumed by Danthurebandara and Rajapaksha (2019) resulting in positive impacts during the decomissioning life cycle stage in 13 out of 18 impact categories for wind generation in Sri Lanka.

Some site-specific issues associated with wind farms are generally not addressed in LCA studies. For example, visual impacts from wind turbines and impacts on local fauna due to bird strike are not considered by LCA impact categories but may be important issues in many countries or communities.

3.3.3.4 Solar

LCAs of solar based electricity generation identify non-fossil resource depletion, HTP, TETP and aquatic ecotoxicity as hotspots for solar generation due to high use of heavy metals and other potentially toxic materials in the construction of solar panels (Gaete-Morales et al., 2018; Gibon et al., 2017; Kabayo et al., 2019; Quek, Alvin Ee, Chen, & Ng, 2019).

Kabayo et al. (2019) investigated six different electricity generation technologies in Portugal considering 11 environmental and human health impact categories. Solar PV generation resulted in the highest impacts of the technologies investigated in the FAETP, human toxicity (non-carcinogenic) categories and the second highest MD impacts after wind generation.

Quek et al. (2019) investigated the impacts of transitioning to a renewable based electricity system by 2050 in Singapore, Malaysia and Brunei and found that increased solar PV generation would result in increases in HTP impacts due to worker exposure to heavy metals and other potentially harmful materials during mining of raw materials and manufacture of PV panels.

The majority of impacts from solar generation are related to the equipment fabrication and construction life cycle stages and positive impacts can be seen if high levels of recycling are achieved during the decommissioning phase (Danthurebandara & Rajapaksha, 2019; Kabayo et al., 2019).

Land use is less frequently considered as an impact category but can be a hotspot of solar electricity generation for grid connected concentrating solar power systems due to the large land area requirements for solar arrays (Gibon et al., 2017).

The GWP of solar power generation is generally reported to be higher than wind or hydro generation although significantly lower than fossil-based electricity generation. In Portugal, a GWP of 51 gCO_{2eq}/kWh for solar PV was reported compared to 23 gCO_{2eq}/kWh for wind and 4-17 gCO_{2eq}/kWh for hydro systems (Garcia et al., 2014). In mainland Greece, a GWP of 55 gCO_{2eq}/kWh was obtained for solar PV versus 28 gCO_{2eq}/kWh for wind and 4-11 gCO_{2eq}/kWh for hydro (Orfanos et al., 2019).

3.3.3.5 Biofuels and Waste

The biofuels and waste category includes a wide range of different fuel types and technologies such as solid biofuels, biogas, liquid biofuel and electricity produced from combustion of renewable municipal waste. The environmental impacts for biofuels vary depending on the technology under consideration, the impact categories considered and country or site-specific considerations.

In terms of GWP performance, biofuels are often reported as having the poorest performance compared to other renewable electricity technologies although generally better than fossil fuel generation. Orfanos (2019) reported a GWP for biomass of 146 gCO_{2eq}/kWh compared to 4-55 gCO_{2eq}/kWh for other renewable technologies and 335-1296 gCO_{2eq}/kWh for fossil fuel based technologies (Orfanos et al., 2019). Similarly, Roinioti and Koroneos (2019) reported GWP of 54 gCO_{2eq}/kWh for biomass/biogas electricity production compared to 2-44 gCO_{2eq}/kWh for renewable technologies and 510-1,067 gCO_{2eq}/kWh for fossil fuel generation. In this study biomass/biogas had the worst performance of the seven technologies considered in the impact categories of EP and tropospheric ozone precursor potential.

In Chile, biogas performed better in terms of GWP than solar PV and fossil-based fuels but worse than hydro and wind generation. Combined heat and power biomass performed worse than the other renewable technologies but better than fossil fuel technologies in terms of GWP. It was also noted in this study that electricity from natural gas had 10%–84% lower impacts than biomass for seven of the eleven impact categories considered (Gaete-Morales et al., 2018).

3.3.4 Country Specific Factors

The environmental performance of electricity supply and generation technologies operating in different countries or regions can vary significantly due to country or region-specific factors. These factors include the availability and quality of both fossil fuel and renewable energy resources, technology or emissions abatement equipment used, climate, transmission and distribution networks and socio-economic factors.

For example, in Chile, it was reported that the ODP impacts of electricity (11 $\mu gR11_{eq}$) were low in comparison to a median based on a literature review (25 $\mu gR11_{eq}$) due to both the use of imported gas in liquefied form which avoided the use of long-distance pipelines and the associated use of ozone depleting fire suppressants and a relatively high level of solar radiation in Chile which increases the efficiency of solar electricity generation (Gaete-Morales et al., 2018).

A comparison of electricity generation and supply between the five regional supply grids in India found significant variation in LCA results. GWP per kWh, for example, was nearly twice as high in the Eastern grid as in the North-eastern grid. One of the key contributors to this variation was found to be differences in the technology used to produce electricity from hard coal such as the age of generation technology and the presence or absence of emission abatement equipment. The other factor noted was the very high transmission and distribution losses associated with some of the regional grids with losses as high as 62% in Jammu and Kashmir compared to a national average 24% (Hossain et al., 2018).

3.4 Issues and Benefits with Increased Renewable Generation

Many nations are planning for increased proportions of renewable electricity generation due to both decreased costs of renewable generation technology (e.g. wind and solar), which now make renewable generation competitive compared to fossil fuel generation, and to help meet GHG reduction targets. As well as the expected reduction in GHG emissions, a transition to higher levels of renewable generation can result in other benefits such as decreased reliance on imported fuels. There are also potential issues associated with increased renewable electricity generation including the variable output of some renewable technologies, greater infrastructure and construction impacts, and the potential for burden shifting. These issues are expanded below.

3.4.1 Security of Supply

Electricity generation in many countries relies heavily on imports of fossil fuels such as gas and coal. A transition to more domestically produced renewable energy can reduce a country’s reliance on imports for electricity generation and improve security of supply. For example, electricity generation in Chile relies heavily on fossil fuels (approx. 46% in 2017) and currently all coal is imported due to limited domestic resources. A desire to reduce reliance on imported resources is one of the reasons Chile is pursuing targets to generate 60% of its electricity from locally-available renewable resources by 2035 and 70% by 2050 (Raugei, Leccisi, Fthenakis, Escobar Moragas, & Simsek, 2018).

New Zealand is currently almost self-sufficient in terms of electricity supply with relatively small amounts of imported coal and oil complementing local resources. In contrast to the example of Chile, security of supply concerns in New Zealand are directly related to a high reliance on renewable generation due to issues such as ‘dry’ years when hydro inflows are reduced and potential mismatch between demand and supply during periods of peak demand. These issues are discussed further in Section 3.4.2.

3.4.2 Variability of Supply

The supply of some renewable electricity generation such as wind and solar is not constant but is dependent on insolation in the case of solar and the wind climate in the case of wind. These factors mean that wind and solar generation varies both daily and seasonally. Generation peaks and troughs can result in a mismatch between demand and supply particularly at daily or seasonal peak times such as early evening or winter when solar production is low. This requires wind and solar generation to be supplemented with more flexible supply technologies such as fossil fuels or other more flexible renewables such as hydro and biofuels. Alternatively, additional renewable capacity or battery storage can be installed to provide generation to cover periods of peak demand however this can have significant cost implications which can negatively impact on the competitiveness of renewable generation.

There are also potential grid management issues associated with a variable supply. Heard, Brook, Wigley, and Bradshaw (2017) identified that with a high penetration of renewable energy there is a need for both augmented transmission networks and to ensure ancillary services will be provided to ensure power quality and reliability. These ancillary services include frequency control and voltage control which can both be a concern when there is a large proportion of variable generation.

These are significant issues for New Zealand. The current high level of hydro generation in New Zealand makes the electricity system vulnerable to ‘dry’ years when there is a prolonged period of low inflows to hydro reservoirs. When insufficient storage is available this can result in high spot prices for electricity or the implementation of measures to reduce demand. For example, in 1992, 2001, 2003 and 2008 the New Zealand public were asked to conserve electricity as part of official conservation campaigns (ICCC, 2019a). Increased levels of renewable generation within the New Zealand electricity mix will either require a continued gas peaking generation capacity or measures such as battery storage, increased demand response or increased levels of more flexible renewable generation such as pumped hydro, biomass or hydrogen to adequately manage this risk. The ICCC (2019a) concluded that a mix of these measures is likely to be required to eventually achieve 100% renewable electricity generation.

The future impacts of climate change will also lead to changes in both hydro lake inflows and the wind climate which will impact upon renewable energy generation. It is predicted that during winter and spring there will be an increase in rainfall for the west of both the North and South Islands due to climate change impacts (MfE, 2018) with resulting increased inflows to South Island hydro-lakes. It is also possible that summer precipitation and inflows will be reduced resulting in a flattening of the annual cycle of hydro-generation capacity from the South Island hydro generation lakes (Renwick, Mladenov, Purdie, McKerchar, & Jamieson, 2010). Wind patterns are expected to become more north-easterly and anticyclonic during summer with stronger westerlies over central New Zealand during the winter (MfE, 2018). This is likely to result in an increase in the wind generation capacity in winter which is the least windy season. An increase in both hydro and wind power capacity during the winter months could reduce the mismatch between generation and demand during peak winter demand periods. In addition, predictions of increased temperatures could both reduce the winter electricity demand due to reduced heating demand and increase the summer electricity demand due to increased use of air conditioning and increased demand for energy for irrigation (Renwick et al., 2010).

3.4.3 Life-Cycle Stage

Most adverse impacts associated with fossil fuel-based generation occur during the operational life-cycle stage and specifically the combustion of fuel within the power station. In contrast, the greatest impacts from renewable generation tend to be associated with manufacture of materials, fabrication and construction of the generation infrastructure although the operational phase can include significant emissions such as geothermal fugitive emissions and hydropower biogenic emissions. This has implications when comparing the environmental impacts of renewable generation with fossil fuel-based generation.

To obtain an accurate comparison of the impacts of renewable electricity with other forms of generation, it is important to take a full life cycle approach as comparing only a subset of life cycle stages can give incomplete results. For example, if only operational impacts are considered the most significant impacts associated with renewable generation will be ignored. The decommissioning phase can also be important and can lead to benefits in some impact categories if high levels of recycling are anticipated.

This is an important consideration for increased renewable generation in New Zealand. For example, some of the specialised equipment required for renewable generation infrastructure (e.g. PV panels, wind turbines) are imported to New Zealand. The impact of imported embodied emissions from countries which may have relatively high environmental footprints for manufacturing activities due to factors such as carbon intensive electricity supply and lack of environmental regulation can be an important factor determining impacts associated with manufacture of materials and fabrication.

3.4.4 Burden Shifting

Another issue associated with increased proportions of renewable energy within electricity systems is that while a reduction in fossil fuels can be expected to result in decreases in climate change impacts, burden shifting can also be expected with resulting increased impacts in other categories. Impact categories such as metal depletion, human, terrestrial and aquatic toxicity, and land use can all be negatively affected by increases in renewable generation. Careful planning and appropriate regulation, market controls and performance standards are important to minimise the potential adverse impacts of renewable generation (Mason, Page, & Williamson, 2013; Quek et al., 2019).

3.5 Transmission and Distribution Networks

The impacts of transmission and distribution networks are often excluded from LCA studies of electricity (Kabayo et al., 2019; Quek et al., 2019; Roinioti & Koroneos, 2019). The impacts associated with transmission and distribution can be very country specific and dependent on factors such as geography, size and population density.

Gargiulo, Girardi, and Temporelli (2017) undertook a review of LCA studies of electricity networks and concluded there were two main methodological issues associated with LCAs of electricity networks. The first was the definition of the functional unit with a tension between identifying a functional unit which met the specific needs of the LCA goal and a need to standardise functional units to enable comparison between different studies. The second issue was the importance of electricity losses to the impacts associated with electricity networks and the related need to accurately define the generation mix over the defined timeframe of the study in order to calculate impacts associated with losses.

In studies where grid losses are considered, they are often the source of the greatest impacts associated with distribution and transmission. An LCA of electricity generation and supply in Portugal between 2003 and 2012 found the losses from the transmission and distribution network contributed 5% and 9% to the seven environmental impact categories considered. The transmission grid infrastructure had a negligible contribution (less than 0.8%) and the distribution grid represented less than 4.5% of the impacts(Garcia et al., 2014).

In an LCA of the Greek generation and transmission system, the transmission system had relatively small impacts in all categories (<28%) compared to electricity generation. In the categories of ADP, AP, EP, GWP, FAETP and MAETP most (>45%) of the transmission impacts were due to grid losses. The construction and installation of transmission lines had a greater influence on the categories of ODP (60%), HTP (70%) and TETP (60%). The distribution system was not considered in this study (Orfanos et al., 2019).

4 Methodology Considerations

4.1 Overview

LCA is a tool that can be used to help identify impacts that may occur in the future. There are several factors to consider when considering the future impacts of electricity generation and supply. These include the timing of impacts associated with different generation technologies (Section 4.2), the choice of indicators, such as different climate change metrics (Section 4.3), and the use of attributional or consequential LCA approaches (Section 4.4).

In addition, the Planetary Boundary (PB) approach seeks to put possible future impacts into a global perspective (Section 4.5).

These issues and methodologies related to assessing the future impacts of electricity generation and supply are discussed in the following sections.

4.2 Timing of Impacts

When comparing different electricity generation technologies or generation mixes, the life cycle inventories can be very different, and it is important to consider all life-cycle stages as discussed in Section 3.4.3.

Depending on the goal of the LCA study, it may also be important to consider when the impacts occur over time. Impacts associated with electricity generation and supply are generally quantified on a per kWh or GWh basis which enables comparisons between different generation technologies, abatement options or locations. This is usually achieved by spreading embodied impacts such as manufacture of materials, fabrication or construction impacts over the expected lifetime of the technology. While this provides an effective means to make direct comparisons, this approach does not provide information on the timing of emissions or the ability to determine the impact of an activity on a specific time-bound target such as a GHG reduction target. For example, spreading emissions that occur at the beginning of the life-cycle over the lifetime of the technology does not provide any information on the short-term impacts as an early peak in emissions, for example due to construction of an electricity generating plant, will be obscured by averaging these emissions over the lifetime of the plant.

An alternative approach was used by M. Walmsley et al. (2018), as described in Section 3.1, where annual GHG emissions were assessed over a number of years and construction GHG emissions were fully allocated to the year prior to expected plant commissioning rather than spreading the emissions over the lifetime of each plant. The purpose was to obtain a better representation of the impact of increasing renewable energy generation as regards both the timing of GHG emissions and the contribution of embodied emissions.

4.3 Climate Change Metrics

The use of GWP to quantify potential climate change impacts is an accepted convention throughout LCA literature and has been used by the Intergovernmental Panel on Climate Change (IPCC) since 1990 (Houghton, Jenkins, & Ephraums, 1990). GWP is defined as the time-integrated radiative forcing due to a pulse emission of a given component, relative to a pulse emission of an equal mass of CO_2 (Myhre et al., 2013). GWP is most frequently integrated over a 100-year timeframe (GWP_{100}) with a 20-year timeframe also commonly used (GWP_{20}).

GWP is a mid-point indicator based on radiative forcing and its benefits include its widespread acceptability and its simplicity which makes it relatively easy to calculate and understand although a number of limitations or disagreements in relation to GWP have been identified. Sarofim & Giordano (2018) identified the following criticisms of GWP within the literature:

- Radiative forcing as a measure of impact is not as relevant as temperature or damages: Shine, Fuglestvedt, Hailemariam, and Stuber (2005) argued that, because of the different life-times of different gases, different GHGs could have the same GWP but result in a different temperature change at a given point in time.
- The assumption of constant future GHG concentrations is unrealistic: The radiative efficiency of the key GHGs (CO_2, CH_4, N_2O) is known to decrease with increasing concentrations (Reisinger, Meinshausen, & Manning, 2011) but the impact of increasing GHG concentration is not reflected in the calculation of GWP.
- Discounting is preferred to a constant time period of integration: Schmalensee (1993) argued that GWP is not based on a damage comparison and, to achieve the optimal policies for GHG control, the discounted marginal damages of emissions from different gases must be compared.
- Disagreements about the choice of time horizon in the absence of discounting: The use of GWP_{20} versus GWP_{100} or other time horizons can give different results depending on the relative proportions of short-lived or long-lived GHGs and can be used to reflect different value judgements about the relative importance of short-term versus long-term impacts (Ocko et al., 2017).
- Dynamic approaches would lead to a more optimal resource allocation over time: An example of a dynamic approach is the MERGE model developed by Manne and Richels (2001) which incorporates both economic as well as physical considerations and incorporates the marginal cost of abating each GHG.
- GWP does not account for non-climatic effects: In addition to climate effects, the emission of some GHGs can have direct impacts on human health by adversely affecting air quality measures such as particulate matter and ozone levels (Shindell, 2015).
- Pulses of emissions are less relevant than streams of emissions: Alvarez, Pacala, Winebrake, Chameides, and Hambur (2012) noted that GWP is based on radiative forcing of single emission pulses which do not capture the climatic consequences of real-world investment and policy decisions that would be better simulated as emission streams.

Many of the limitations that have been identified with GWP_{100} relate to the differences in impacts associated with long versus short-lived GHGs and the lack of differentiation of the timescale of impacts from different GHGs. Gases which have been identified as influencing global temperatures can be divided into two main categories: well mixed greenhouse gases (WMGHG) and near-term climate forcers (NTCF). WMGHG are GHGs which have atmospheric lifetimes that are long enough for them to become well mixed into the atmosphere and therefore have climate impacts on a long-term global scale. Water vapour (H_2O), CO_2, N_2O, CH_4 and ozone (O_3) are the primary WMGHGs. NTCF are compounds whose impact on the climate occurs primarily within the first decade after their emission and includes sulphur dioxide (SO_2), black carbon, organic carbon, non-methane volatile organic compounds (NMVOC), nitrogen oxides (NOx), and carbon monoxide (CO). CH_4 is recognised as a WMGHG but can also be considered a NTCF due to its relatively short atmospheric perturbation time of about a decade. Due to their short-lived properties, NTCFs are considered to primarily impact upon the rate of climate change and the peak temperature rather than long-term temperature increases

(Åström & Johansson, 2019; Myhre et al., 2013). Table 4.1 provides the expected atmospheric lifetimes of the main WMGHGs.

Table 4.1 Characteristics and Characterisation Factors of Well Mixed Greenhouse Gases (Myhre et al., 2013)

Chemical Name	Chemical Formula	Lifetime (Years)	GWP 20-yr	GWP 100-yr	GTP 20-yr	GTP 50-yr	GTP 100-yr
Carbon dioxide	CO_2	[1]	1	1	1	1	1
Methane	CH_4	12.4	84	28	67	14	4
Fossil methane	CH_4	12.4	85	30	68	15	6
Nitrous Oxide	N_2O	121	264	265	277	282	234

Several alternative climate change metrics have been suggested by researchers to better quantify the temporal aspects of climate change impacts. A case study of three hypothetical bioenergy systems was used to compare 15 different impact assessment methods which varied in their treatment of biogenic carbon fluxes, the type of climate change impacts they address, and differences in time horizon and time preference. The authors concluded that an interpretation of different climate change metrics must be based on an understanding that the different methods focus on different aspects of climate change and represent different time preferences (Brandão, Kirschbaum, Cowie, & Hjuler, 2019).

Farquharson et al. (2017) undertook a comparative LCA of electricity produced from coal and natural gas in the United States using the climate metrics of global warming potential, global temperature change potential (GTP), technology warming potential, and cumulative radiative forcing. It was concluded that the qualitative results of all the climate metrics were similar for the scenarios considered which led to increased confidence in the results. It was also noted that the use of alternative metrics can support the robustness of an analysis and provide additional information about life cycle climate impacts. Similarly, Levasseur et al. (2016) argue that it is useful to use complementary metrics to obtain a better understanding about the robustness of an LCA study and that obtaining a range of results from different metrics should be part of communicating the ambiguity and uncertainty of the results.

GTP has been suggested as an alternative or complementary metric to GWP. GTP is based on a simple analytical model of the climate system which is used to compute the temperature change at some given time due to either a pulse or sustained emission of a gas. It is argued that it is further down the cause-effect chain than GWP and therefore more relevant (Shine, Berntsen, Fuglestvedt, Skeie, & Stuber, 2007; Shine et al., 2005). GTP has been used in addition to GWP in several recent LCA studies (Åström & Johansson, 2019; Brandão et al., 2019; Farquharson et al., 2017).

A UNEP/SETAC initiative has undertaken a global consensus process over several years to agree an updated life cycle impact assessment (LCIA) framework and to recommend a

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[1] No single lifetime can be given

non-comprehensive list of environmental indicators and LCIA characterisation factors for a range of impact categories. Climate change has been one of the priority impact categories and global guidance on a number of categories including climate change was released in 2018 (Jolliet et al., 2018). Two main challenges were identified in relation to climate change indicators:

1. How to best characterise gases with lifetimes ranging from a few years for CH_4, up to several hundreds or thousands of years for WMGHG such as CO_2 or CFCs.
2. How to consider the new climate science developments on climate-carbon cycle feedbacks (the changing climate influencing itself) and on the contributions from NTCFs.

It was concluded that a single metric cannot adequately assess the different contributions of climate forcing agents to both rapid shorter-term temperature changes and long-term temperature increases. The resulting guidance strongly recommended the use of both GWP_{100} and GTP_{100} as climate change indicators.

GWP_{100} is included to assess shorter-term climate change, addressing environmental and human health consequences from the rate of climate change (e.g. lack of human and ecosystems adaptation) (Jolliet et al., 2018). Allen et al. (2016) demonstrated that GWP_{100} was numerically close to GTP_{40} and can therefore be interpreted as a proxy for temperature impacts within about four decades. Allen et al. (2016) noted that GWP_{100} overstates the importance of current NTCF emissions unless significant reductions of all climate pollutants result in temperatures nearing their peak soon after mid-century and therefore GWP_{100} is not appropriate to represent long-term impacts.

GTP_{100} is recommended to assess long-term climate change impacts, reflecting the long-term (i.e. over centuries) effects from climate change (e.g. future temperature stabilisation, sea level rise) (Jolliet et al., 2018). The characterisation factors for both GWP and GTP recommended by the IPCC (Myhre et al., 2013) are provided in Table 4.1.

4.4 Attributional and Consequential LCA

Attributional modelling is concerned with describing the life cycle impacts of a product or service based on a given situation which can either be past, present or a predicted future. In contrast, consequential modelling is concerned with the consequences or implications of one or more changes to a product life cycle and how that will affect both the life cycle impacts of the product itself and the resulting life cycle impacts of other products or services that are affected by the change. Consequential LCA attempts to answer 'what-if' questions in relation to a change arising in a product system. It generally involves expanded system boundaries in order to account for secondary impacts on the overall economic and technological system, which have been likened to the ripples of a stone thrown on a lake (Ekvall & Weidema, 2004). A fundamental difference in the use of attributional versus consequential model is the choice of what is modelled and how the system boundary is defined (Zamagni, Guinée, Heijungs, Masoni, & Raggi, 2012).

There is wide-ranging debate within LCA literature regarding the appropriate use of attributional and consequential modelling and its role within LCA as well as the related issue of whether average or marginal data should be used. ILCD guidance recommends the use of an attributional approach for 'micro-level decision support' where changes in the background or other systems are expected to be small and a consequential approach using long-term marginal processes for ‘meso/macro level decision support’ where large scale changes are expected (European Commission, 2010). However, recent contributions have included criticism from Ekvall et al. (2016) that the ILCD guidance on how to choose between consequential and attributional LCA, and the use of marginal or average processes, is internally inconsistent and inconsistent with previous research.

Some have suggested that social responsibility requires that a consequential modelling approach in LCA is always taken (Weidema, Pizzol, Schmidt, & Thoma, 2018). Brander, Burritt, and Christ (2019), however, suggest that both consequential and attributional approaches should be adopted for different but complementary purposes. And Yang (2019) argues that a dichotomy between attributional and consequential LCA is unnecessary, and that the terms should be eliminated as all the models used in LCA are consequential models and therefore the term attributional fails to capture the essence of LCA and the term consequential is redundant.

One approach to assessing the environmental impact of future activities is to adopt a prospective attributional modelling approach where an attributional approach is taken utilising anticipated future average life cycle inventory data. This approach is generally utilised by considering a range of potential future scenarios. A prospective attributional approach can be used to investigate total (absolute) environmental impacts of a system in the future or after improvement/mitigation options are implemented (Chobtang, 2016). Chobtang, McLaren, Ledgard, and Donaghy (2017) adopted a prospective attributional approach to investigate possible future farm intensification scenarios in pasture-based dairy systems in New Zealand and concluded that this approach was useful in identifying the environmental trade-offs and hotspots among different potential future scenarios.

Soimakallio, Kiviluoma, and Saikku (2011) also supported the use of scenarios for both attributional and consequential future focused LCA associated with electricity production. They noted that, due to scenarios involving a certain degree of uncertainty, an appropriate number of scenarios should be carried out in order to provide a range of perspectives under various relevant market conditions.

A review of 60 LCA papers concluded that, since the modelling principles of attributional and consequential LCA are the same, what distinguishes them is the choice of the processes to be included in the system but that the identification of those processes is often done inconsistently, using different arguments, which leads to different results. Use of scenario modelling was proposed as a scientifically sound basis to model potential product-related futures with respect to technology development, market shift, and other variables (Zamagni et al., 2012).

One of the key requirements for undertaking consequential LCA is identification of the marginal technology for which demand will either increase or decrease due to a change in the product system under consideration. The identification of the marginal technology is often not straightforward. Mathiesen, Münster, and Fruergaard (2009) analysed the identification of marginal electricity and heat technologies in LCA studies involving the Danish energy system based on a historical analysis. It was found that the actual marginal technology was not the same as would have been identified based on theoretical recommendations of consequential LCA and that those recommendations were applied inconsistently by LCA practitioners.

It has also been noted that, while expanding system boundaries to include more impacts and the use of marginal data can increase understanding of the impacts of a change within a system, it can also raise concerns about validation and that there is a trade-off between comprehensiveness and uncertainty in consequential analysis. The benefit of comparing different scenarios within consequential LCA is therefore explorative, rather than for accounting purposes (Jones, Gilbert, Raugei, Mander, & Leccisi, 2017).

An alternative approach has been proposed by Forin, Berger, and Finkbeiner (2020) who argue that value choices made during the goal and scope phase of an LCA should be the determining factor in selecting between average or incremental/marginal data.

4.5 Planetary Boundary Approach

LCA is increasingly being used in the context of a PB approach. The PB approach was first described by Rockström et al. (2009) and further defined by Steffen et al. (2015). It is based on the premise that human induced changes to the natural environment can potentially change the natural processes that have existed within certain limits throughout the Holocene epoch and that have supported the development of contemporary human societies. Rockström et al. (2009) identified nine inter-linked PBs that underpin the planet's biophysical subsystems or processes and that operating outside of these boundaries may have deleterious impacts on human society. Steffen et al. (2015) further defined the PBs and identified a hierarchy of PBs with climate change and biosphere integrity identified as the core PBs that provide the planetary-level overarching systems within which the other PB processes operate (Steffen et al., 2015).

The PBs as described by Steffen et al. (2015) are presented in Figure 4.1. Each PB is defined in terms of one or more 'control variables' which represent a quantitative measure of the PB. A safe operating space (green) is defined for each PB as well as a high risk (red) zone. Between these two zones is a 'zone of uncertainty' (yellow) which represents both the acknowledged uncertainties with the current state of knowledge for each boundary and the time required to react when a high-risk zone is approaching. It is also acknowledged that the current state of knowledge for some boundaries is insufficient to determine a boundary with sufficient certainty at this stage and these are identified as 'boundary not yet quantified' (grey).

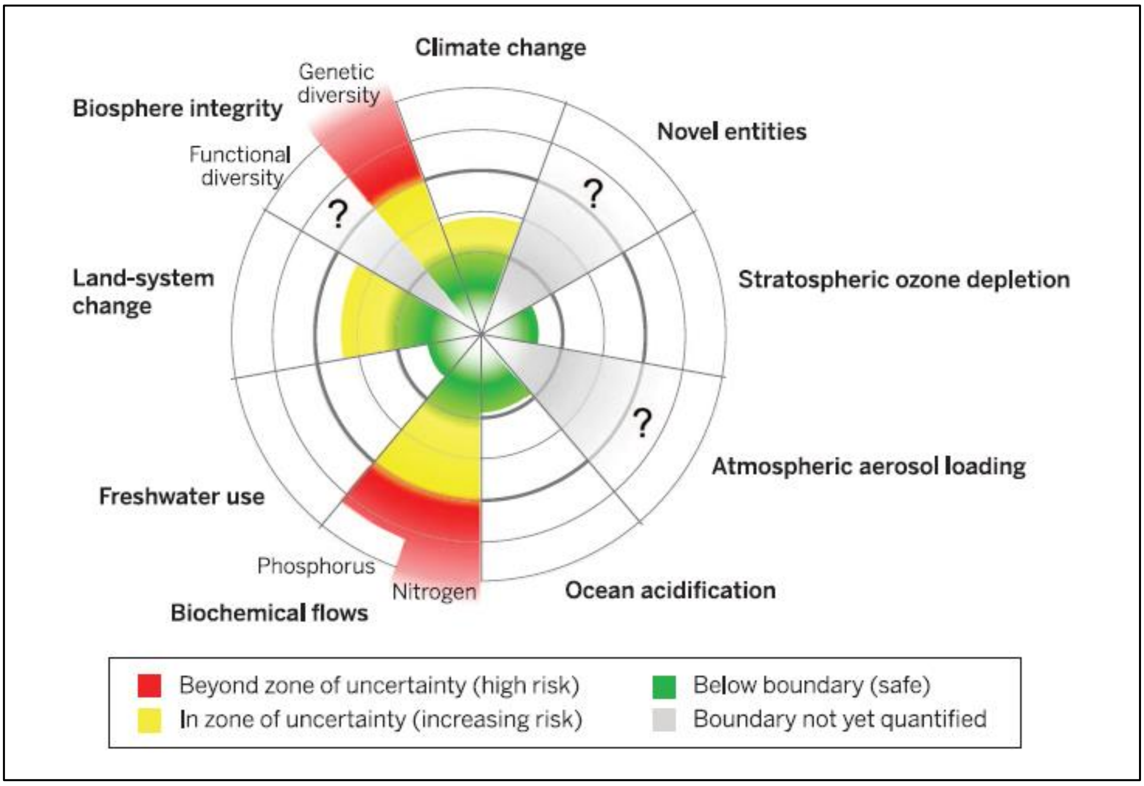

Figure 4.1 Planetary Boundaries and Current Status of Control Variables (Steffen et al., 2015)

The PB approach can be combined with LCA to determine the absolute sustainability of an industry, product or activity in terms of its contribution to the relevant PBs (Bjørn et al., 2020). This requires the relevant control variable at the global PB level to be translated into a national, regional, sectoral or product limit against which the LCA results can be compared. This translation from a global limit requires value judgements in terms of how a global limit should be allocated across different countries and activities.

In a New Zealand example of an absolute sustainability assessment, Chandrakumar et al. (2020) assessed the climate change performance of the New Zealand economy using two different climate thresholds and both consumption and production-based GHG accounting methods. Production based accounting is based on the principle that a country, sector, company or other economic unit is responsible for the GHG emissions associated with the goods and services it produces. In contrast, consumption-based accounting allocates the GHG burden based on the goods and services consumed regardless of where they are produced. Similarly, the share of the calculated global carbon budget (CB) can be allocated to a country or sector based on different sharing principles. Chandrakumar et al. (2020) used both grandfathering and economic value sharing principles with both consumption and production-based allocation used for economic sharing.

The assessment showed that the New Zealand carbon footprint exceeded the allocated CB shares irrespective of the value and modelling choices. When the CB was assigned to sectors using the economic sharing principle, a few sectors performed within their limits, but most exceeded them. It was concluded that the value and modelling choices made when assessing the climate change performance of a country in relation to absolute climate thresholds can have a significant impact on the results obtained.

A planetary boundaries approach was combined with electricity system modelling to investigate the optimum electricity generation mix in the United States in 2030 which would minimise cost while also meeting eight planetary boundaries. An electricity mix which replaces existing coal and natural gas plants with onshore wind, PV, natural gas with CCS and bio-energy with CCS was identified as able to meet all eight of the planetary boundaries considered including climate change. The cost of this electricity mix was 20% higher than a generation mix optimised to only meet a 2°C climate change target based on the Paris Agreement (Algunaibet et al., 2019a, 2019b).

5 Life Cycle Assessment of Future New Zealand Electricity Supply: Goal and Scope Definition, and Inventory Analysis

5.1 Life Cycle Assessment Method

The LCA methodology involves four different phases. The four phases are summarised below together with the relevant section where each phase is addressed in this study:

- Goal and scope definition: Defines the goal and scope of the study including the functional unit, system boundary and types of impacts to be assessed (Sections 5.2 to 5.4);
- Inventory analysis: An analysis of the inventory of inputs and emissions associated with the product system defined in the scope (Sections 5.5 to 5.8);
- Impact assessment: Assessment of the environmental impacts of the product system based on the identified inventory of inputs and emissions and one or more impact assessment methodologies (Section 6); and
- Interpretation: Discussion and interpretation of the inventory analysis and impact assessment results including conclusions and recommendations where relevant (Sections 7 to 9).

5.2 Goal and Scope Definition

The goal of this study is to assess the life cycle based potential environmental impacts and benefits of future New Zealand low voltage electricity supply on an annual basis using a range of future electricity supply and demand scenarios.

The scope of the study includes:

- extraction, processing and transport of fossil fuels (coal and gas);
- operation and maintenance activities of power suppliers (thermal, geothermal and renewable);
- transmission and distribution of electricity to the final consumer;
- construction of new electricity generation infrastructure; and
- operation, maintenance and construction of distributed solar generation.

An LCA approach is adopted in this assessment using the CML-2016 LCIA methodology (Guinée et al., 2002) for the List 1 LCIA indicators recommended in the New Zealand Whole of Building Whole of Life Framework (BRANZ, 2019b) and in EN15978:2011 (BSI, 2011b). Life Cycle Inventory (LCI) based indicators related to primary energy demand are also included in the assessment. These indicators were selected as they are used within the New Zealand Whole of Building Whole of Life Framework (BRANZ, 2019b) and the LCAQuick Tool (BRANZ, 2019a) of which the outputs of this study are intended to be incorporated. In addition, climate change impacts are also assessed using GTP_{100} as recommended by UNEP/SETAC guidance on climate change LCIA indicators (Jolliet et al., 2018).

Table 5.1 gives a summary of the LCIA and LCI indicators considered in this study.

5.3 Functional Unit

The functional unit for the study is the annual supply of low voltage electricity to New Zealand consumers.

Table 5.1: Summary of Impact Categories

Indicator	Abbreviation	Unit	LCIA Method
Global warming potential (100 years)	GWP_{100}	kg CO_{2eq}	CML-2016
Global temperature change potential (100 years)	GTP_{100}	kg CO_{2eq}	IPCC AR5
Stratospheric ozone depletion potential	ODP	kg $CFC11_{eq}$	CML-2016
Acidification potential	AP	kg SO_{2eq}	CML-2016
Photochemical ozone creation potential	POCP	kg $Ethene_{eq}$	CML-2016
Eutrophication potential	EP	kg $Phosphate_{eq}$	CML-2016
Abiotic depletion potential (elements)	ADP elements	kg Sb_{eq}	CML-2016
Abiotic depletion potential (fossil fuels)	ADP fossil	MJ	CML-2016
Primary energy demand (renewable and non-renewable resources)	PED total	MJ (net calorific value)	-
Primary energy demand (non-renewable resources)	PED non-renew	MJ (net calorific value)	-
Primary energy demand (renewable resources)	PED renew	MJ (net calorific value)	-

5.4 Future New Zealand Electricity Scenarios

The future impacts of New Zealand electricity were explored using five future electricity scenarios developed by MBIE (2019b) and three future electricity scenarios developed by ICCC (2019a). The purpose and scope of these scenarios are described in Sections 2.5.1 and 2.5.2 and the key modelling assumptions are summarised in Appendix B. Data for each scenario was provided by MBIE (2019g) and ICCC (2019b).

Section 5.4.1 provides an overview of the generation size and technology mix for each of the scenarios and Section 5.4.2 outlines the new build generation capacity installed under each scenario.

5.4.1 Generation Size and Technology Mix – MBIE and ICCC Scenarios

The five MBIE and three ICCC electricity scenarios each represent a different level of total generation and a different mix of generation technologies. Table 5.2 provides cumulative generation between 2018 and 2050 for the MBIE scenarios and cumulative generation between 2019 and 2035 for MBIE and ICCC scenarios to enable a comparison between all eight scenarios. Based on cumulative generation between 2019 and 2035, the scenario with the highest level of generation is the MBIE Disruptive scenario followed by the MBIE Environmental and Growth scenarios, then the ICCC Accelerated Electrification, MBIE Reference, ICCC 100% Renewable, MBIE Global and finally the ICCC Business as Usual scenario with the lowest total generation. The cumulative generation between 2018 and 2050 for the MBIE scenarios reflect the same order.

Table 5.2 also provides the proportion of renewable energy for all eight scenarios in 2035 and in 2050 for the MBIE scenarios. In 2035, the ICCC 100% Renewable scenario has the highest amount of renewable generation (100%) followed by the ICCC BAU scenario (92.7%). The ICCC Accelerated Electrification and MBIE Environmental both have 91.7% renewable generation followed by the MBIE Growth (91.3%), Disruptive (91.1%), Reference (90.7%) and Global (89.9%) scenarios. With the exception of the ICCC 100% Renewable, the remaining scenarios represent a similar amount of renewable generation in both 2035 and 2050 with a difference of less than 3% between the highest and lowest amounts of renewable generation.

Table 5.2: Cumulative Generation and % Renewables - MBIE and ICCC Scenarios

	Scenario	Cumulative Generation 2019-2035 (GWh)	Cumulative Generation 2018-2050 (GWh)	% Renewables 2035	% Renewable 2050
MBIE Scenarios	Global	778,322	1,558,407	89.9	94.7
	Reference	814,127	1,709,868	90.7	95
	Growth	845,923	1,842,026	91.3	95.5
	Environmental	862,608	1,894,463	91.7	96.1
	Disruptive	873,394	1,941,361	91.1	94.9
ICCC Scenarios	BAU	771,747	-	92.7	-
	100% Renewable	779,308	-	100	-
	Accelerated Electrification	840,820	-	91.7	-

Figure 5.1 presents the annual generation mix and size for each of the scenarios.

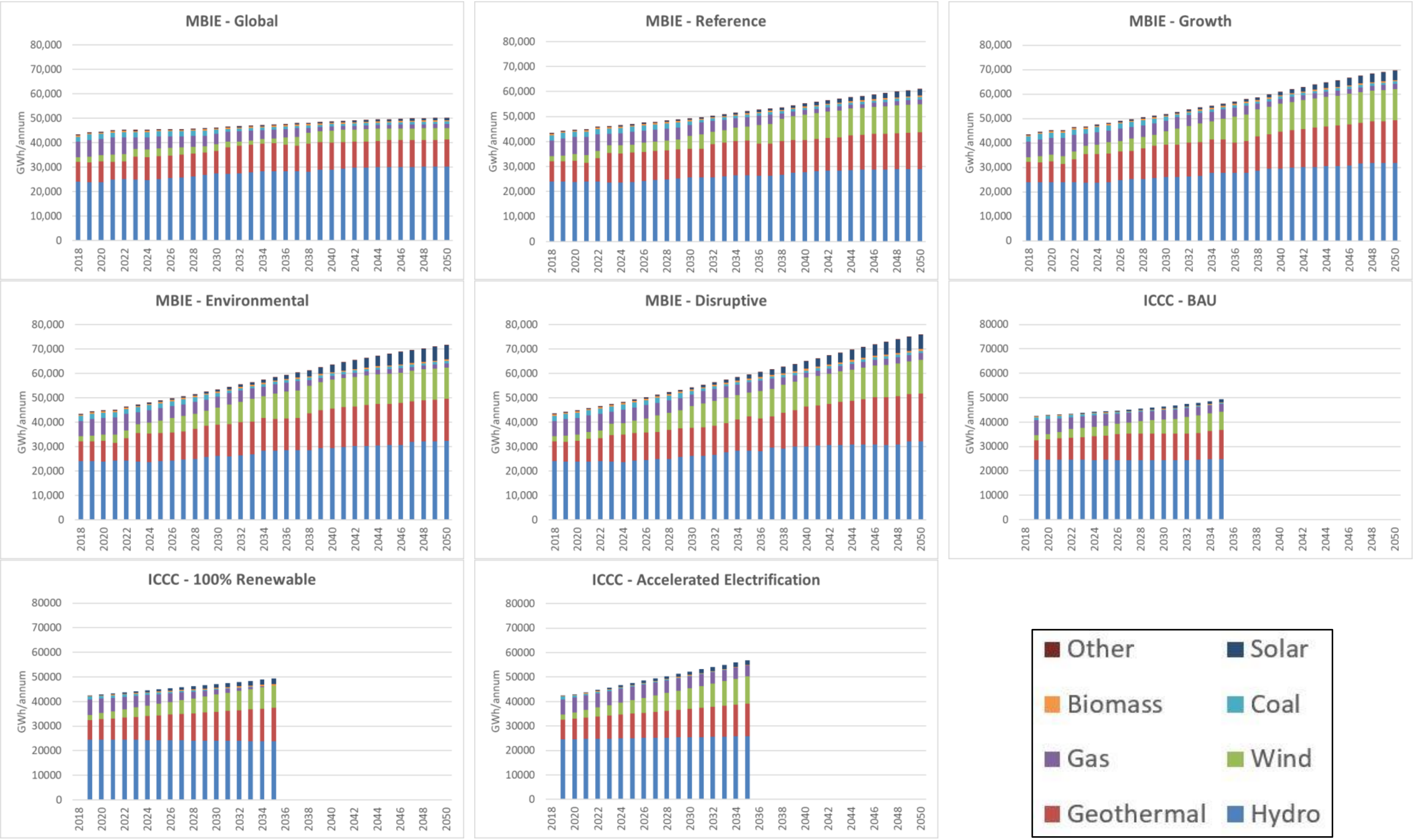

Figure 5.1: Annual Generation Size and Mix of MBIE and ICCC Future Electricity Scenarios

5.4.2 New Build Generation Capacity – MBIE and ICCC Scenarios

A summary of the new build generation capacity installed during the modelling periods for each MBIE and ICCC scenario is provided in Table 5.3.

Table 5.3: New Generation Capacity Installed during Modelling Periods

		Generation Technology					
		Gas (MW)	Geothermal (MW)	Hydropower (MW)	Wind (MW)	Utility Solar (MW)	Distributed Solar (MW)
MBIE Scenarios 2018-2050	Global	750	635	765	1,335	0	823
	Reference	930	1,070	406	3,390	110	2,319
	Growth	1,350	1,385	1,052	4,125	998	2,876
	Environmental	1,130	1,385	1,092	4,513	1,077	4,770
	Disruptive	1,340	1,685	1,378	4,713	1,145	4,770
ICCC Scenarios 2019-2035	Business as Usual	227	507	131	1,576	-	876
	100% Renewable	-	712	293	2,779	450	893
	Accelerated Electrification	647	687	293	2,575	350	893

5.5 Inventory Analysis Overview

The future environmental impacts of the New Zealand electricity system were investigated through the development of three models using GaBi (version 9.5.2.49) LCA modelling software and utilising the ecoinvent (version 3.5) datasets[2] supplemented with New Zealand specific data where available. Each of the models represents a different life-cycle stage as follows:

- Operation and maintenance of electricity generation (O&M): Impacts associated with the supply of source fuels (gas and coal), operation and maintenance of electricity generation, parasitic electricity use by generators, and the operation and maintenance of distributed solar generation. This model does not include electricity generation infrastructure but does include infrastructure associated with the supply and transport of source fuels. Further details on this model are provided in Section 5.6.
- Transmission and distribution (T&D): Impacts associated with the Transmission and Distribution of electricity including transmission and distribution losses and sulphur hexafluoride use and losses. Further details on this model are provided in Section 5.7.

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[2] Ecoinvent datasets are available in three different formats; the 'allocation, cut off by classification' format is utilised in GaBi modelling software.

- New build electricity generation infrastructure (Infrastructure): Impacts of new build electricity generation infrastructure including fossil fuel and renewable generation infrastructure. Existing electricity generation infrastructure is not included as the associated emissions and impacts have occurred in the past and are not considered relevant to an assessment of future impacts in the context of an absolute sustainability assessment (see Section 5.8.1). Further details on this model are provided in Section 5.8

The results obtained from these three models are combined for each scenario and year to provide an assessment of the total life-cycle impacts associated with future New Zealand electricity supply on an annual basis from 2018 to 2050 for MBIE Scenarios and from 2019 to 2035 for ICCC Scenarios.

5.6 Inventory Analysis – Operation and Maintenance (O&M) Model

5.6.1 Overview

The O&M inventory consists of relevant ecoinvent (version 3.5) datasets supplemented with New Zealand specific input and emissions data where available. Emissions data published by MBIE for the 2017 year are used as the primary source of New Zealand specific emissions. Emissions associated with combustion of coal and gas are based on the emission factors used by MBIE (2019d) and in the New Zealand's Greenhouse Gas Inventory 1990-2017 (MfE, 2019b). Wherever relevant, default electricity datasets are replaced with the relevant ecoinvent dataset for New Zealand electricity (i.e. low, medium or high voltage). Hydropower and geothermal generation are represented by LCI data from relevant literature. All power station infrastructure inputs are excluded and assessed in the separate Infrastructure model (see Section 5.8).

Figure 5.2 provides an overview of the plans within the O&M model. Specific calculations, assumptions and information sources for each component of the model are described in Sections 5.6.2 to 5.6.12. Parasitic use is applied to all generation technologies, except distributed solar, and is described in Section 5.6.10.

For the ICCC BAU scenario used in this study, data on generation mix was provided by the ICCC on an annual basis for all years from 2019 to 2035. For the ICCC 100% Renewable and Accelerated Electrification scenarios, generation data was provided for the 2019 and 2035 years only. The annual generation mix is estimated for the intervening years by assuming the generation mix increases or decreases on a linear basis between these two years. In reality, changes in the generation mix would be more stepwise in nature as new generation capacity comes on stream and existing generation is retired. The annual results for these two scenarios are therefore considered less realistic on a yearly basis than the results for the ICC BAU and MBIE-forecasted scenarios.

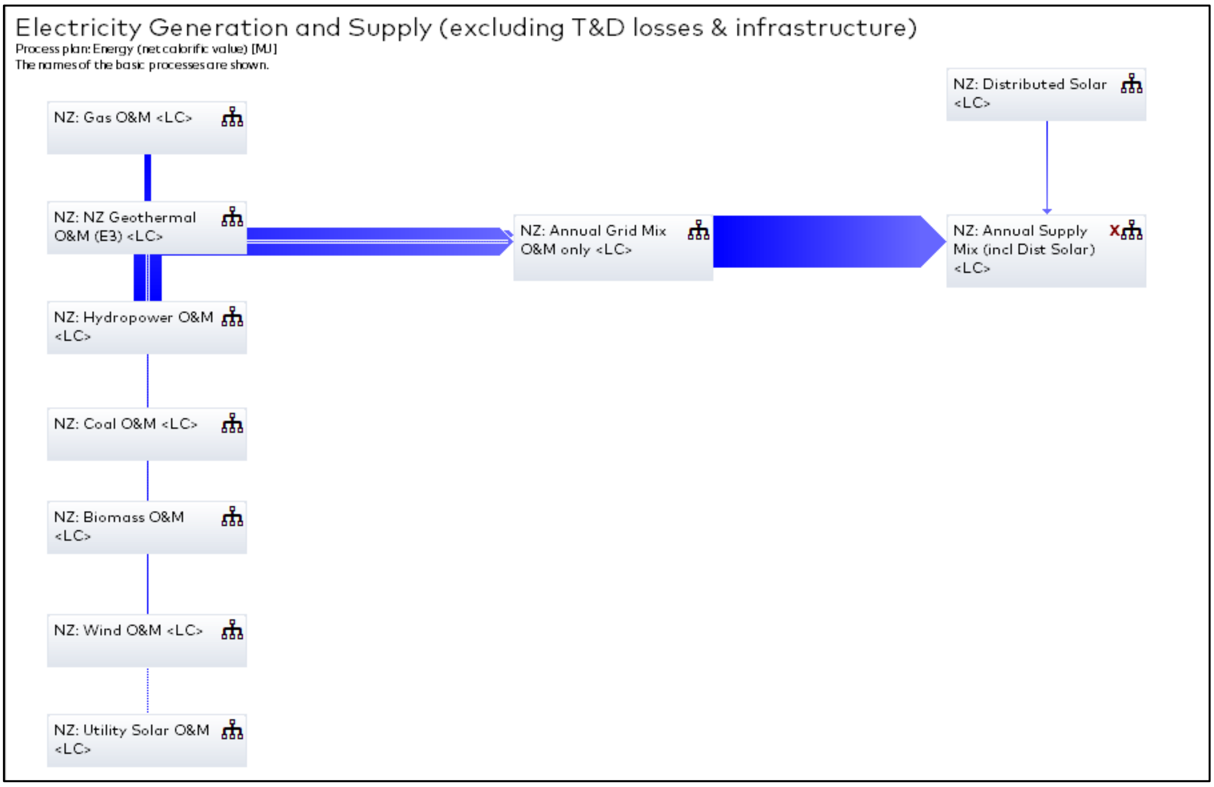

Figure 5.2: Overview of Generation Technology and Generation Mix Components of the Operations and Maintenance Model

5.6.2 Coal Generation

An overview of the coal operation and maintenance plan is provided in Figure 5.3. Further details are provided in Sections 5.6.2.1 to 5.6.2.3.

This plan includes the following components:

- <u>Sub-bituminous coal mining</u>: Domestic coal supply is represented by the ecoinvent process for hard coal mining in Australia with modifications where New Zealand specific data is available (Section 5.6.2.1.
- <u>Hard coal imports:</u> Imported coal is represented by the ecoinvent process for hard coal mining in Indonesia and associated transport to New Zealand (Section 5.6.2.1).
- <u>Coal storage and transport</u>: Losses of coal during transport and storage, transport between the production or import site and the power station, and the mix of imported to domestic coal is represented by the ecoinvent process for the Australian coal market (Section 5.6.2.2).
- <u>Coal power plant operation:</u> Operation of the Huntly coal fired power station is represented by an ecoinvent process for electricity produced from coal in Australia with modifications where New Zealand specific data is available (Section 5.6.2.3).
- <u>Coal fired heat and power plant operation:</u> Operation of coal fired cogeneration plants is represented by an ecoinvent process for electricity produced from coal in combined heat and power plants in Australia with modifications where New Zealand specific data is available (Section 5.6.2.3).
- <u>Electricity from coal production mix:</u> Allocates a proportion of coal electricity generation to electricity only power stations and cogeneration plants (Box 5.1).
- <u>Parasitic use:</u> See Section 5.6.10.

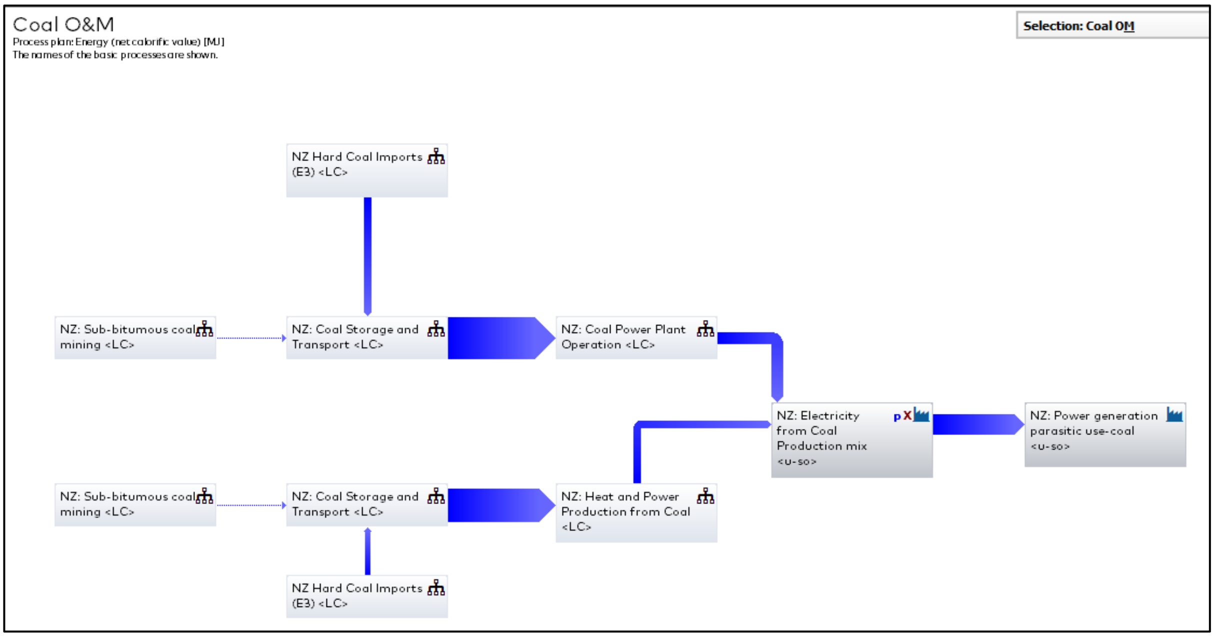

Figure 5.3: Overview of Electricity from Coal Operations and Maintenance (O&M) Plan

5.6.2.1 New Zealand Coal Mining and Coal Imports

It is assumed that only sub-bituminous coal is used for electricity production although approximately 3% of coal used in cogeneration plants is lignite (MBIE, 2019a). All sub-bituminous coal mined within New Zealand has been sourced from open-cast mines since 2016. Between 2014 and 2018, approximately 80% of sub-bituminous coal used in New Zealand was sourced from New Zealand mines and 20% from imports (MBIE, 2019a). It is assumed that this proportion of local to imported sub-bituminous coal applies to coal used for future electricity generation. It was reported by Parsons Brinckerhoff (2012) that imported coal used at the Huntly power station in 2011 was sourced from Indonesia and it is assumed that Indonesia continues to be the source of imported coal used for electricity generation.

New Zealand specific emissions factors are adopted for fugitive CH_4 emissions associated with New Zealand mined coal. This is based on the total annual fugitive emissions of CH_4 from coal mining in New Zealand during 2017 reported by MBIE (2019d) (Appendix C) divided by the total domestic coal supply during 2017 reported by MBIE (2019a) (Appendix D) as outlined in the following formula:

$$Emissions\ Factor\ CH4\ ({}^{kg}/_{kg\ coal}) = \frac{Annual\ fugitive\ emissions\ (T), 2017}{Domestic\ coal\ supply\ (T), 2017}$$

The relevant input data and resulting emission factor are provided in Table 5.4.

Table 5.4:Fugitive Emissions from Coal Mining in New Zealand

Pollutant Gas	Fugitive Emissions from Coal Mining in 2017 (t)	Domestic Coal Supply in 2017 (t)	Emission factor (kg_{CH4}/kg_{coal})
CH_4	5,282	2,918,563	0.0018

5.6.2.2 Coal Storage and Transport

The coal storage and transport plan incorporates assumptions regarding the proportion of imported and domestic coal for electricity generation. In addition, a nominal transport distance of 100 km by diesel freight train is assumed between the coal mine or port and coal power station. Coal losses of 0.215% during transportation are assumed based on the ecoinvent default value.

5.6.2.3 Combustion Emissions – Electricity from Coal

New Zealand specific emission factors are calculated for combustion emissions associated with electricity produced from coal at the Huntly power station. Emission factors for emissions of pollutant gases (CO_2, CH_4, N_2O, CO, NMVOC, NO_x and SO_2) are calculated per kWh of electricity produced based on the energy value of coal used to produce electricity at Huntly in 2017 (MBIE, 2019a) (Appendix D), multiplied by the relevant combustion emission factor, and divided by the generation from the Huntly coal plant in 2017 (MBIE, 2019f). The combustion emission factors used were those adopted in New Zealand's Greenhouse Gas Inventory 1990-2017 (MfE, 2019b) and by MBIE (2019d).

The calculation of pollutant emission factors associated with combustion of coal to produce electricity is represented by the following formula:

$$Pollutant\ Emission\ Factor\left({}^{kg}/_{kWh}\right) = \frac{Coal\ used\ to\ produce\ Huntly\ electricity\ in\ 2017\ (MJ)\ x\ Combustion\ Emission\ Factor\left({}^{kg}/_{MJ}\right)}{Electricity\ generation\ from\ coal\ at\ Huntly\ in\ 2017\ (kWh)}$$

The relevant input data and resulting emissions factors for pollutant gases are provided in Table 5.5.

Table 5.5: Combustion Emissions for Electricity from Coal in New Zealand

Pollutant Gas	Coal Used to Produce Electricity in 2017 at Huntly (MJ)	Combustion Emission Factor for Coal (kg/MJ)	Electricity Generation from Huntly Coal in 2017 (kWh)	Emission factor (kg/kWh)
CO_2	5.68×10^9	0.0922	5.17×10^8	1.01
CH_4		9.5×10^{-7}		1.04×10^{-5}
N_2O		1.42×10^{-6}		1.56×10^{-5}
CO		8.55×10^{-6}		9.40×10^{-5}
NMVOC		4.75×10^{-6}		5.22×10^{-5}
NO_x		3.61×10^{-4}		3.97×10^{-3}
SO_2		3.87×10^{-4}		4.26×10^{-3}

Coal and gas fired cogeneration plants produce both heat and electricity as useful co-products and therefore the emissions from cogeneration plants must be allocated between the heat and electricity produced. There are a number of different methods that can be used to determine the allocation of emissions to the heat and electricity co-products with varying results. Tereshchenko and Nord (2015) analysed seven different allocation methods and applied each of these methods to a district heating system based on a NGCC plant. The different methods resulted in a wide range of allocations, with the allocation to electricity vary from 94% using the 200% method to 61.7% using the alternative generation method. Similarly, Gao et al. (2018) applied six different allocation methods to CO_2 emissions from a coal fired combined heat and power plant. The different methods resulted in the allocation of emissions to electricity ranging from 39% based on energy content to 78% based on entropy change.

Due to an absence of New Zealand data on the amount of heat produced from cogeneration facilities or the relative efficiency of electricity and heat production, it has not been possible to adopt any of these commonly used allocation methods. For the purposes of this study, a conservative approach has been adopted of allocating the same emissions per kWh calculated for electricity generated at electricity only plants to the electricity generated at cogeneration plants. The impacts of this allocation are explored further in Section 6.4.2.

The methods used to determine the amount of coal and gas generation originating from electricity only and cogeneration plants and, for the cogeneration category in the ICCC scenarios, the amount of cogeneration allocated to gas, coal and biomass are described in Box 5.1.

Box 5.1: Generation from Electricity Only and Cogeneration Plants

The future electricity generation scenarios provided by MBIE (2019g) do not differentiate between coal and gas generation produced in electricity only power plants and that produced from cogeneration plants. Until 2029 the ‘electricity from coal production mix’ process, which applies to both MBIE and ICCC scenarios, assumes 60% of coal generation originates from electricity only plants and 40% from cogeneration plants based on the actual average generation split between 2014 and 2019 (MBIE, 2020a) (Appendix F). From 2030, 100% of coal generation is from cogeneration plants coinciding with the anticipated decommissioning of coal fired electricity at the Huntly Power Station (MBIE, 2019b).

Similarly, between 2018 and 2050, the ‘electricity from natural gas production mix’ process, which applies to both MBIE and ICCC scenarios, assumes 83% of natural gas generation originate from electricity only plants and 17% from cogeneration plants based on the actual average generation split between 2014 and 2019 (MBIE, 2020a) (Appendix F).

The ICCC BAU scenario provides a single cogeneration category for fossil fuel cogeneration and the 100% Renewable and Accelerated Electrification scenarios provide a single cogeneration category for biomass and fossil fuels. Based on the historical split of cogeneration from coal and gas between 2016 and 2019 (MBIE, 2020a), it is assumed that 40% of future fossil fuel cogeneration is from coal and 60% is from gas under the BAU scenario. The proportion of cogeneration from biomass under the BAU scenario is approximately 21% in 2019. Accordingly, the combined cogeneration category under the 100% Renewable and Accelerated Electrification scenarios is allocated 21% to biomass, 32% to coal and 47% to gas in 2019. This proportion is kept constant for all years under the Acceleration Electrification scenario. Under the 100% Renewable scenario, cogeneration from biomass increases to 100% while gas and coal reduce to 0% by 2035.

5.6.3 Gas Generation

An overview of the gas operations and maintenance plan is provided in Figure 5.4. Further details are provided in Sections 5.6.3.1 to 5.6.3.3.

This plan includes the following components:

- Offshore gas production: New Zealand offshore gas production is represented by the ecoinvent process for offshore gas production in Norway with the exclusion of emissions of gases for which New Zealand specific data is available (Section 5.6.3.1).
- Onshore gas production: New Zealand onshore gas production is represented by the ecoinvent process for onshore gas production in the Netherlands with the exclusion of emissions of gases for which New Zealand specific data is available (Section 5.6.3.1).
- Natural gas mix: Accounts for the onshore/offshore mix of gas used for electricity and the emission of gases for which New Zealand specific data is available (Section 5.6.3.1).
- Transmission and distribution of natural gas: Accounts for the emission of gases during transmission of natural gas to gas power plants for which New Zealand specific data is available (Section 5.6.3.2).
- Gas power plant operation: The operation of gas fired power stations is represented by an ecoinvent process for electricity produced from a NGCC power plant in Australia with modifications where New Zealand specific data is available (Section 5.6.3.3).
- Natural gas heat and power cogeneration plant operation: The operation of natural gas cogeneration plants is represented by an ecoinvent process for electricity produced from natural gas in combined heat and power, NGCC plants in Australia with modification where New Zealand specific data is available (Section 5.6.3.3).
- Electricity from natural gas production mix: Allocates a proportion of natural gas electricity generation to electricity only power stations and cogeneration plants (see Box 5.1).
- Parasitic use: See Section 5.6.10.

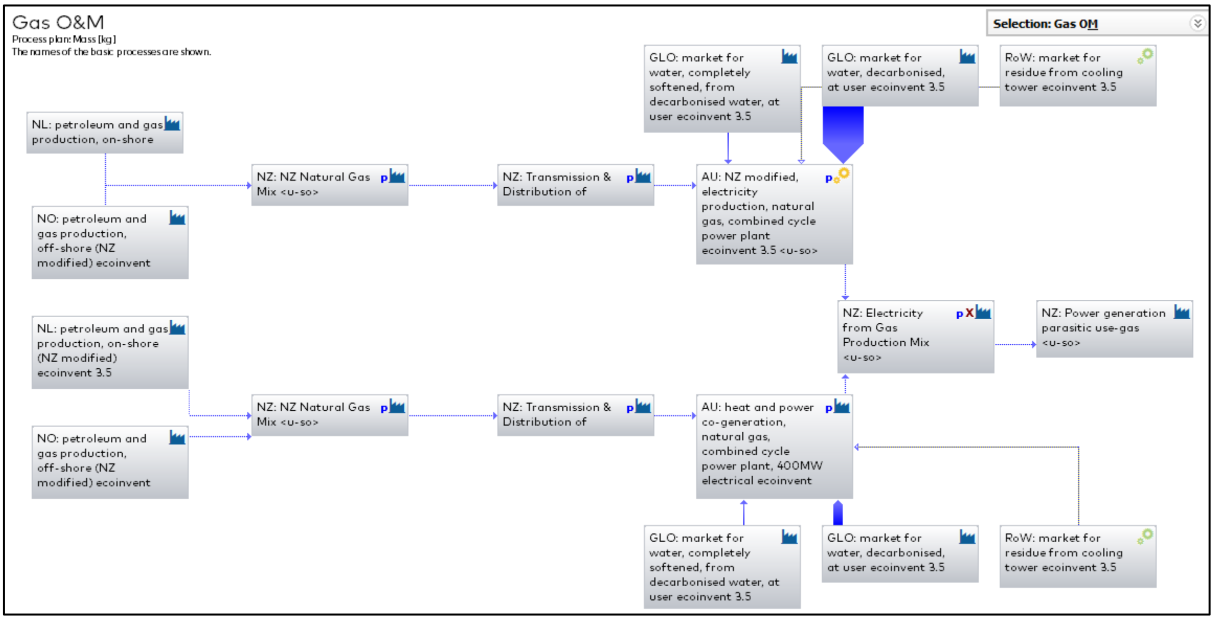

Figure 5.4: Overview of Electricity from Gas Operation and Maintenance (O&M) Plan

5.6.3.1 Onshore and Offshore Gas Production

Currently, approximately 50% of electricity produced from gas is sourced from offshore New Zealand gas fields and 50% from onshore fields based on the split of onshore/offshore production in MBIE data tables for gas in 2017 (MBIE, 2019e) (Appendix E) and advice that approximately 60% of production from the Pohokura field is sourced from offshore wells (Colgan, 2019). It is assumed that this split between offshore and onshore fields continues throughout the modelling period.

New Zealand specific emissions factors are adopted for combustion and fugitive emissions of CO_2, CH_4, CO, N_2O, NMVOC and NO_x associated with exploration and production of natural gas in New Zealand. This is based on the sum of annual combustion emissions from gas extraction and processing, and fugitive emissions from natural gas processing, flaring and natural gas production during 2017 as reported by MBIE (2019d) divided by the total domestic gas supply during 2017 as reported by MBIE (2019e) and outlined in the following formula.

$$Emissions\ Factor\ \left({}^{kg}/_{m3}\,natural\ gas\right) = \frac{E\&P\ Combustion\ Emissions + Flaring\ fugitive\ emissions + Production\ fugitive\ emissions\ (kt)}{Anuual\ gas\ supply\ (Mm3)}$$

The relevant input data and resulting emission factors are provided in Table 5.6.

Table 5.6: Emissions Factors for Exploration and Production of Natural Gas in New Zealand

Gas	Combustion & fugitive emissions from natural gas E&P in 2017 (kt)	Natural gas supply in 2017 (Mm^3)	Emission factor (kg/m^3)
CO_2	860.72	4713.2	0.183
CH_4	8.8396		1.88×10^{-3}
CO	0.092		1.95×10^{-5}
N_2O	0.001		2.12×10^{-7}
NMVOC	1.2987		2.76×10^{-4}
NO_x	1.2774		2.71×10^{-4}

5.6.3.2 Transmission and Distribution of Natural Gas

New Zealand specific emission factors are adopted for fugitive emissions of CO_2, CH_4 and NMVOC's associated with the transmission and distribution of natural gas from gas production facilities to consumers including electricity producers. These emission factors are based on the total fugitive emissions associated with natural gas transmission and distribution in 2017 reported by MBIE (2019d) (Appendix C) divided by the total supply of natural gas in 2017 reported by MBIE (2019e) (Appendix E) and outlined in the following formula.

$$Emission\ Factor\ \left({}^{kg}/_{m3}\right) = \frac{Fugitive\ emission\ from\ transmission\ \&\ distribution, 2017\ (kt)}{Annual\ gas\ supply, 2017\ (Mm3)}$$

The relevant input data and resulting emissions factor are provided in Table 5.7.

Table 5.7: Emissions Factors for Transmission and Distribution of Natural Gas in New Zealand

Gas	Fugitive emissions from natural gas T&D in 2017 (kt)	Natural gas supply in 2017 (Mm^3)	Emission factor (kg/m^3)
CO_2	1.296	4713.2	2.75×10^{-4}
CH_4	8.448		1.79×10^{-3}
NMVOC	0.00014		2.97×10^{-8}

5.6.3.3 Combustion Emissions – Electricity from Natural Gas

Emission factors for emissions of pollutant gases (CO_2, CH_4, N_2O, CO, NMVOC and NO_x) are calculated per kWh of electricity produced based on the energy value of natural gas used to produce electricity in gas fired electricity only power stations in 2017 (MBIE, 2019e), multiplied by the relevant combustion emission factor, and divided by the generation from gas fired electricity only power stations in 2017 (MBIE, 2019f). The combustion emission factors used were those adopted in the New Zealand's Greenhouse Gas Inventory 1990-2017 (MfE, 2019b) and MBIE (2019d).

The calculation of pollutant emission factors associated with combustion of natural gas to produce electricity from gas fired power stations is represented by the following formula:

$$Pollutant\ Emission\ Factor\ \left({}^{kg}/_{kWh}\right)$$
$$= \frac{Natural\ gas\ used\ to\ produce\ electricit\ in\ 2017\ (MJ)\ x\ Combustion\ Emission\ Factor\ \left({}^{kg}/_{MJ}\right)}{Electricity\ generation\ from\ natural\ gas\ in\ 2017\ (kWh)}$$

The relevant input data and resulting emissions factors for pollutant gases are provided in Table 5.8.

Table 5.8: Combustion Emissions for Electricity from Natural Gas in New Zealand

Pollutant Gas	Natural Gas Used in Electricity Only Generation in 2017 (MJ)	Combustion Emission Factor for Natural Gas (kg/MJ)	Generation from Electricity Only Plants in 2017 (kWh)	Emission factor (kg/kWh)
CO_2	45.69×10^9	0.0541	56.03×10^8	0.4412
CH_4		9.0×10^{-7}		7.34×10^{-6}
N_2O		9.0×10^{-8}		7.34×10^{-7}
CO		4.14×10^{-5}		3.38×10^{-4}
NMVOC		4.5×10^{-6}		3.67×10^{-5}
NO_x		1.71×10^{-4}		1.39×10^{-3}

The allocation of gas generation between electricity only and cogeneration plants is described in Box 5.1.

5.6.4 Geothermal Generation

The geothermal O&M plan is based on LCI data developed by Saçayon Madrigal (2015) which uses New Zealand specific emission and discharge data for geothermal generation supplemented with LCI data from the Hellisheidi geothermal power plant in Iceland (Karlsdóttir, Pálsson, Pálsson, & Maya-Drysdale, 2015) and a study of four geothermal fields in Italy (Bravi & Basosi, 2014). A 2-Flash Power Plant was chosen to represent geothermal electricity production in New Zealand as this is the predominant technology used in New Zealand (Saçayon Madrigal, 2015). New Zealand specific data used by Saçayon Madrigal (2015) has been updated with more recent information where available.

An overview of the geothermal O&M plan is provided in Figure 5.5.

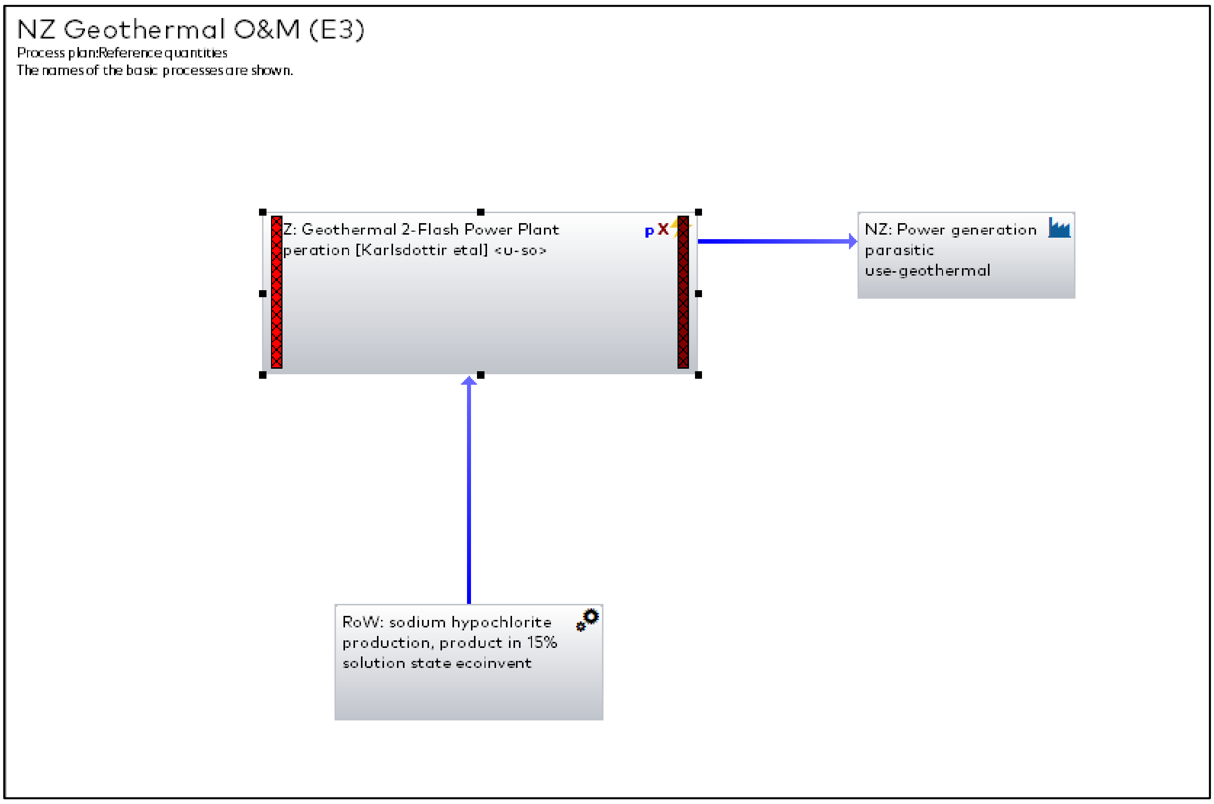

Figure 5.5: Overview of Electricity from Geothermal Operation and Maintenance (O&M) Plan

New Zealand specific emission factors per kWh are calculated for fugitive emissions associated with electricity produced from geothermal energy. These emission factors are based on the total fugitive emissions associated with electricity production from geothermal in 2017 reported by MBIE (2019d) (Appendix C) divided by the total supply of electricity from geothermal in 2017 reported by (MBIE, 2020a) (Appendix F) and outlined in the following formula. The relevant input data and resulting emissions factor are provided in Table 5.9.

$$Fugitive\ Emission\ Factor\left({}^{kg}/_{kWh}\right) = \frac{Annual\ geothermal\ fugitive\ emissions, 2017 (kT)}{Annual\ electricity\ from\ geothermal, 2017\ (GWh)}$$

Table 5.9: Fugitive Emissions for Electricity from Geothermal in New Zealand

Gas	Fugitive Emissions from Geothermal in 2017 (kt)	Electricity produced from Geothermal in 2017 (GWh)	Emission factor (kg/kWh)
CO_2	643.26	7,458	0.0862
CH_4	6.86		9.20×10^{-4}

Discharges to water of arsenic, mercury and hydrogen sulphide (H_2S) from geothermal power plants are estimated based on historical discharges and/or recently revised consent limits reported for the Wairakei geothermal field (Contact, 2019b). Based on historical performance it is assumed that arsenic is discharged at the consent limit, mercury at 80% of the consent limit and H_2S at 50% of the consent limit. It is assumed that discharges to water by Contact Energy are representative of geothermal discharges to water in New Zealand with Contact geothermal production representing 46% of total New Zealand geothermal electricity production for the year ending 30 June 2018 (Contact, 2018; MBIE, 2020a). Emission factors are determined by dividing the annual discharge by the average geothermal generation reported by Contact for the 2018 and 2019 financial years (Contact, 2018, 2019a) as summarised in Table 5.10.

Table 5.10: Basis for Estimates of Discharges to Water from Geothermal Electricity Generation

Discharge to Water	Wairakei Consent Limit	Estimated annual discharge (t/year)	Average annual Contact geothermal generation 2018/19 (GWh)	Emission factor (kg/kWh)
Arsenic	34 tonnes/year	34	3,290	1.03×10^{-5}
Mercury	10 kg/year	0.008	3,290	2.43×10^{-9}
H_2S	630kg/week	16.38	3,290	4.98×10^{-6}

New Zealand based emission factors for discharges of hydrogen sulphide, mercury and isopentane to air from geothermal generation were based on average annual emissions and generation from the Mokai, Rotokawa, Nga Awa Purua and Ngatamariki plants between 2013 and 2018. (Appendix G). This information was obtained from annual monitoring reports submitted to the Waikato Regional Council (Mercury, 2018, 2019a, 2019b). Table 5.11 provides a summary of the calculated emission factors for these discharges to air.

Table 5.11: Emission Factors for Discharges to Air from Geothermal Generation in New Zealand

Discharge to Air	Emission Factor (kg/kWh)
H_2S	2.84×10^{-3}
Mercury	1.31×10^{-7}
Isopentane	1.66×10^{-5}

Emissions to air from geothermal electricity generation for which no New Zealand specific data exists are estimated based on Bravi and Basosi (2014). Following the approach taken by Saçayon Madrigal (2015), this includes estimates of trace metals (cadmium, chromium, copper, lead, manganese, nickel, selenium and vanadium), ammonia (NH_3) and carbon monoxide (CO) using the minimum values reported by Bravi and Basosi (2014).

5.6.5 Hydropower Generation

An overview of the hydropower O&M plan is provided in Figure 5.6.

This plan includes the following main components:

- Reservoir hydropower electricity generation: New Zealand hydropower generation from reservoir hydro systems is represented by an ecoinvent 'Rest-of-World' process for high voltage electricity production from reservoir systems in non-alpine regions. The only modification was the exclusion of hydropower plant infrastructure.
- Run-of-river hydropower electricity generation: New Zealand hydropower generation from run-of-river hydro systems is represented by an ecoinvent 'Rest-of-World' process for high voltage electricity production from run-of-river systems. The only modification was the exclusion of hydropower plant infrastructure.
- New Zealand hydropower generation mix: This process allocates the generation of hydropower between the different types of system which is assumed to be 94% reservoir and 6% run-of-river based on estimates made by Saçayon Madrigal (2015).

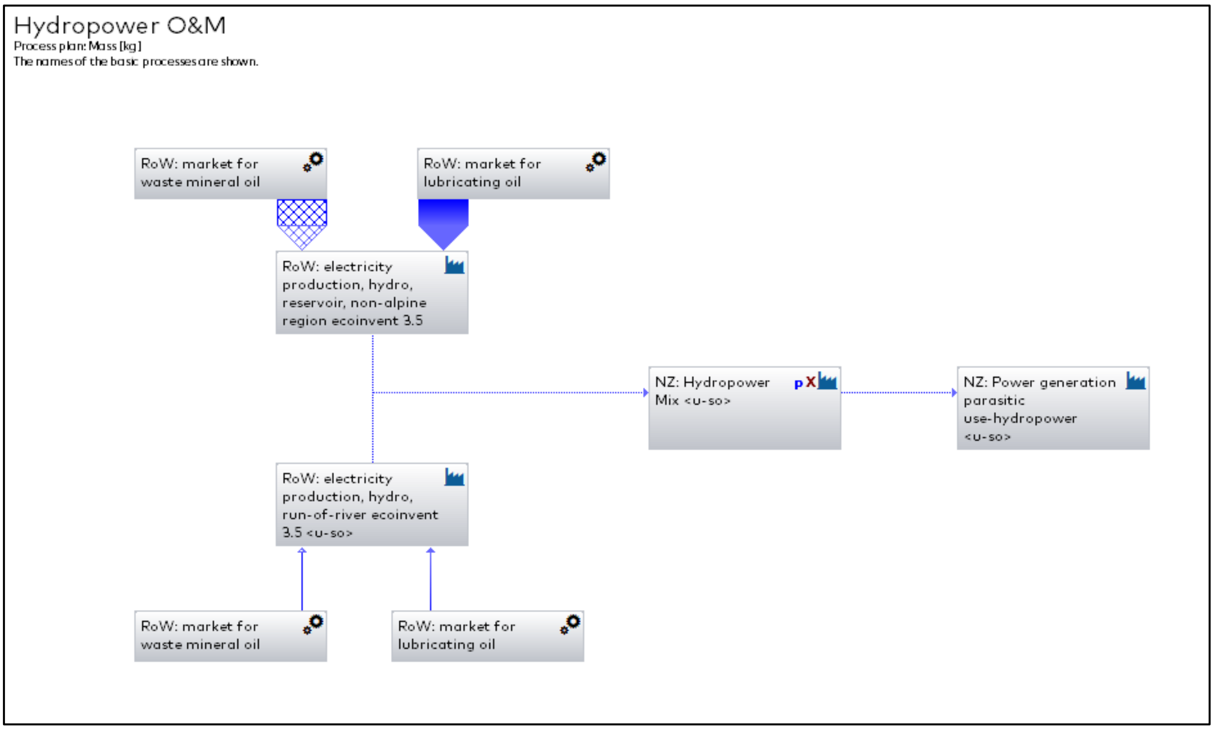

Figure 5.6: Overview of Electricity from Hydropower Operation and Maintenance (O&M) Plan

5.6.6 Wind Generation

An overview of the wind generation O&M plan is provided in Figure 5.7.

This plan includes the following main component:

- Electricity production from wind: New Zealand electricity generation from wind is represented by an ecoinvent Australian process for onshore high voltage electricity production from wind turbines greater than 3 MW capacity. The only modification is the exclusion of the wind turbine infrastructure and wind turbine network connection infrastructure.

Generation from wind turbines greater than 3 MW capacity is selected as representative of future New Zealand generation. The size of existing generating wind turbines in New Zealand are generally less than 3MW capacity but New Zealand is expected to follow the international trend of increasing wind turbine size with future wind turbines expected to be in the 4-6 MW range (Roaring40s Wind Power Ltd, 2020). As significant amounts of new wind generation capacity are constructed, the average size of wind turbines in New Zealand is anticipated to increase to over 3 MW. The two wind farms currently under construction are installing turbines of 3.6 MW and 3.8 MW at Turitea and 4.3 MW at Waipipi (Roaring40s Wind Power Ltd, 2020).

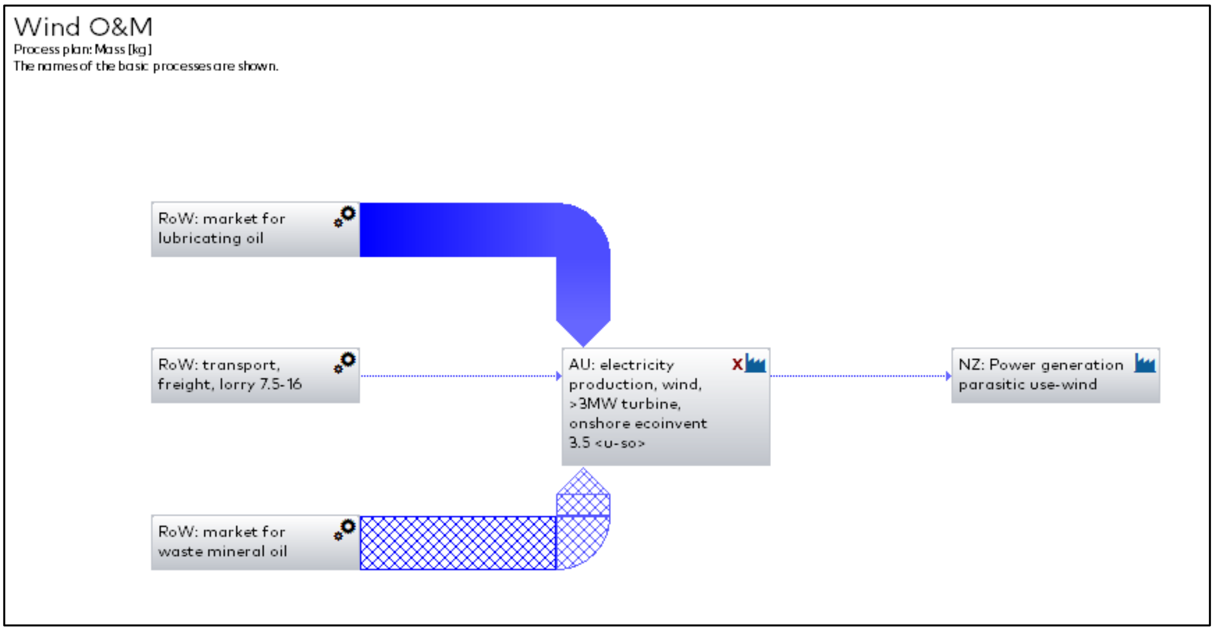

Figure 5.7: Overview of Electricity from Wind Operation and Maintenance (O&M) Plan

5.6.7 Utility Scale Solar Generation

Utility scale solar generation represents large scale solar generation of high voltage electricity. There is currently no utility scale solar generation capacity in New Zealand. Under four of the five MBIE scenarios, utility scale solar generation is anticipated to commence during the 2030s; no utility scale generation is anticipated under the Global scenario. The ICCC 100% Renewable and Accelerated Electrification both anticipate utility scale solar generation by 2035 and no utility generation is anticipated under the BAU scenario.

An overview of the utility scale solar generation O&M plan is provided in Figure 5.8.

This plan includes the following main component:

- Electricity production from utility scale solar: New Zealand electricity generation from utility scale solar is represented by an ecoinvent process for ‘Rest of World’ electricity production from a 20 MW solar tower power plant. The only modification is the exclusion of solar generation infrastructure.

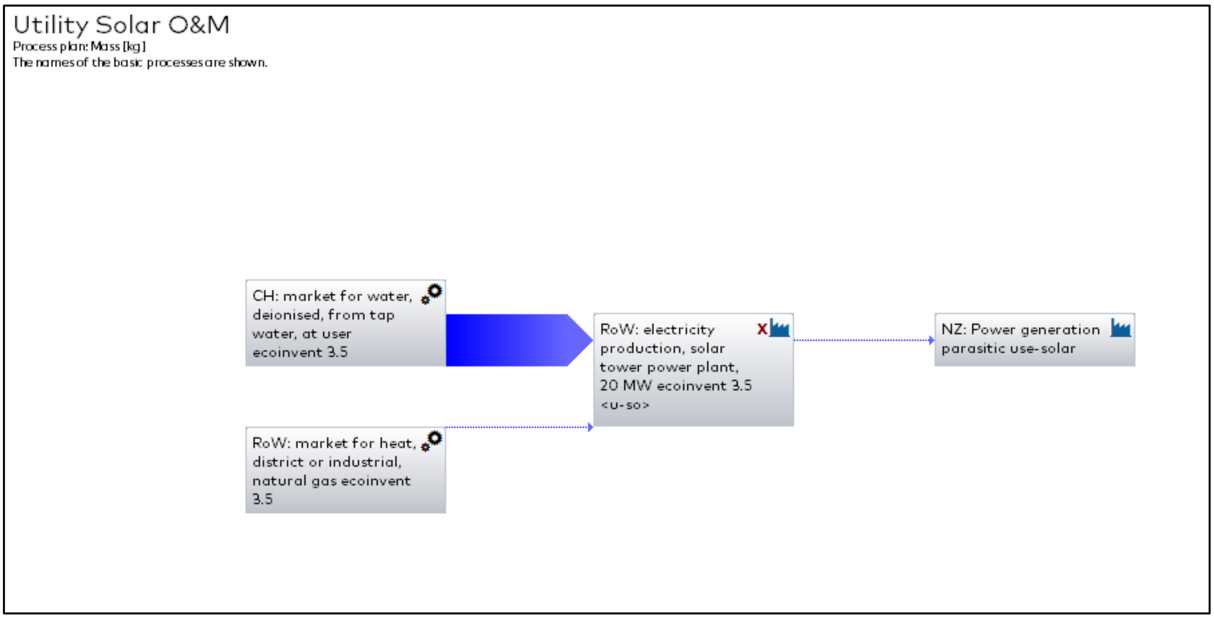

Figure 5.8: Overview of Electricity from Utility Solar Operation and Maintenance (O&M) Plan

5.6.8 Biomass Generation

An overview of the biomass generation O&M plan is provided in Figure 5.9.

This plan includes the following main component:

- Electricity production from biomass: New Zealand electricity generation from biomass is represented by a Swiss ecoinvent process for 2000 kW heat and power cogeneration using wood chips. The only modification is the exclusion of generation infrastructure.

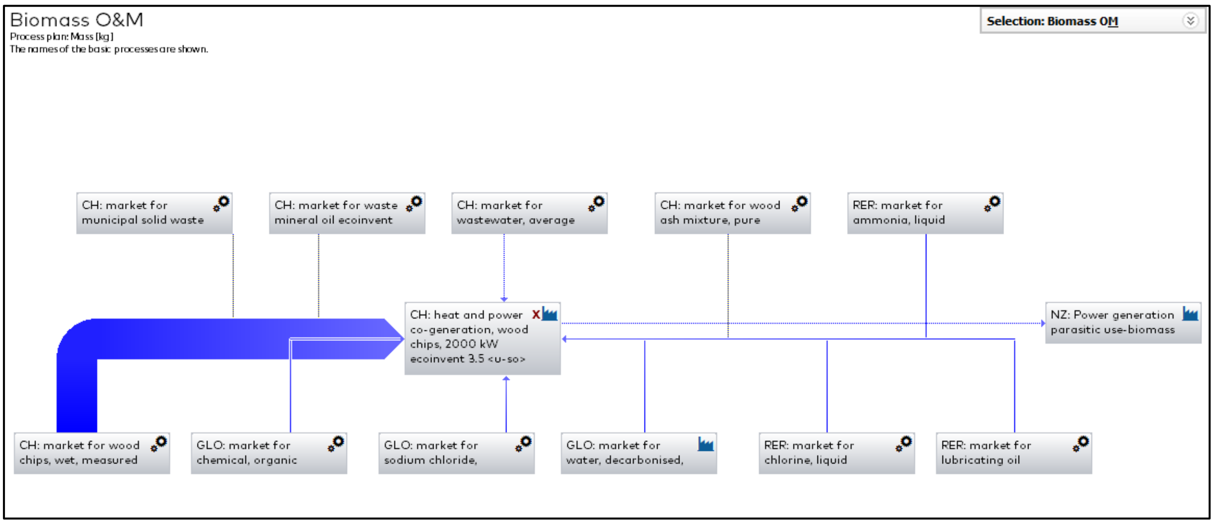

Figure 5.9: Overview of Electricity from Biomass Operation and Maintenance (O&M) Plan

5.6.9 Other Generation

The MBIE EDGS provide yearly figures for net electricity generation by fuel type for generation from hydropower, geothermal, wind, gas, coal, biomass, solar and other. The ‘other’ category includes generation from minor sources such as diesel and waste heat. The waste heat category accounts for 50 GWh of generation per year in all five scenarios for every year from 2018-2050 (Smith, 2020) and accounts for no more than 0.1% of generation per year . Due to the minor contribution of waste heat to the generation mix and the nature of the generation (i.e. use of an otherwise waste resource), generation from waste heat is excluded from the assessment of future environmental life cycle impacts. Total generation reported in the remainder of this report does not include waste heat.

The remainder of the 'other' category is composed primarily of diesel generation from the Whirinaki diesel peaker power station (Smith, 2020). Under the MBIE scenarios, diesel generation only occurs until 2023 after which it is anticipated that the Whirinaki plant will be decommissioned. The greatest amount of diesel generation occurs in 2023 under the Global scenario where it accounts for 0.6% of total generation. The ICCC BAU scenario includes a very small amount of diesel generation but this is combined with the gas generation category for reporting and is not listed as a separate category under the other ICCC scenarios. Diesel accounts for a minor amount of generation but potentially results in a small but not insignificant environmental impact in some impact categories (e.g. GWP) in some years. The small amount of diesel generation is added to the gas generation category and assessed as if it were gas generation. This will underestimate the impacts of this generation in some impact categories, but this is not considered significant due to the small amount of generation involved.

5.6.10 Parasitic Use by Electricity Generators

Parasitic use, also known as own use, is the use of electricity by generators as part of the generation process. Values for parasitic use are reported by MBIE on an annual basis for the electricity sector as a whole (MBIE, 2020a) (Appendix F) and are not published separately for each fuel type. Table 5.12 provides a summary of this data for the five years between 2014 and 2018 including the percentage of own use compared to gross generation. Based on historical own use figures, 3% parasitic use is assumed in the O&M model for all generation technologies except distributed solar.

Table 5.12: Electricity Losses Due to Generators Parasitic Use 2014-2018

Year	2014	2015	2016	2017	2018
Gross Generation (GWh)	42,228	42,895	42,482	42,889	43,126
Parasitic Use (GWh)	1,310	1,329	1,218	1,304	1,253
% Own Parasitic	3.1%	3.1%	2.9%	3.0%	2.9%

5.6.11 Annual Electricity Grid and Supply Mix

The annual electricity grid mix plan (Figure 5.2) incorporates the future electricity generation mix for each of the eight scenarios. The parameter explorer function of GaBi is used to establish a scenario group for each of the MBIE and ICCC scenarios and an individual scenario for each year within the scenario group. Scenario groups are also established for 1 kWh of each generation technology.

The annual electricity grid mix plan links to each of the technology specific electricity generation plans to allocate an appropriate amount of generation from each generation technology to each year and scenario.

The output of the annual electricity grid mix plan represents grid electricity supplied to the final consumer and therefore transmission and distribution losses are subtracted from the net electricity generation figures published by MBIE and ICCC. Total transmission and distribution losses are estimated to be 6.9% of the reported net electricity generated (see Section 5.7.4) therefore a factor of 0.931 is applied to the net electricity generation figures for each scenario to determine the quantity and impacts of grid supplied electricity to consumers excluding transmission and distribution impacts. Impacts associated with transmission and distribution losses are calculated in the separate T&D plan (see Section 5.7).

The total amount of electricity supplied to consumers includes grid supplied electricity and distributed generation such as residential and commercial rooftop solar PV generation. The majority of solar PV generation is used at the point of generation and therefore is not subject to transmission and distribution losses. A separate plan represents the impacts of distributed solar generation and is described in Section 5.6.12. The annual electricity grid mix and distributed solar generation are combined in the Annual Supply Mix plan to represent the total impacts associated with O&M impacts of electricity supplied to final consumers.

5.6.12 Distributed Solar Generation

The annual figures for solar generation for future scenarios reported by MBIE (MBIE, 2019b) are represented by a single category which includes both distributed solar generation and utility scale solar generation. Unpublished estimates of future distributed solar generation for each scenario were provided by MBIE which enables the differentiation of total solar generation into grid connected and distributed solar generation categories. Data provided by ICCC was differentiated into ‘large solar’ and ‘solar’ categories which is interpreted as utility scale high voltage solar and distributed solar PV generation respectively.

An overview of the distributed solar generation O&M plan is provided in Figure 5.10.

This plan includes the following main components:

- Distributed generation from Single-Si PV Panels: New Zealand distributed generation from single-Si PV panels is represented by an ecoinvent ‘Rest-of-World’ process for low voltage electricity production from single-Si PV panels. The only modification is exclusion of the PV panel infrastructure. The main operational input and output are water and wastewater for cleaning the panels during operation.
- Distributed generation from Multi-Si PV Panels: New Zealand distributed generation from multi-Si PV panels is represented by an ecoinvent ‘Rest-of-World’ process for low voltage electricity production from multi-Si PV panels. The only modification is exclusion of the PV panel infrastructure. As with single-Si panels, the main operational input and output are water and wastewater.
- New Zealand distributed solar generation mix: This process allocates the generation of distributed solar generation between the different types of PV systems which are assumed to be 50% single-crystalline silicon (single-Si) panels and 50% multi-crystalline silicon (multi-Si) panels. Multi-Si and Single-Si technologies made up 93% of global PV panel production in 2017 with multi-Si comprising 61% of global production (Fraunhofer Institute for Solar Energy Systems, 2019). The impacts associated with the ecoinvent datasets for both types of panel are similar, although single-Si panels have slightly higher impacts for some indicators, therefore a 50:50 split is considered conservative.

The method for calculating parasitic use is provided in Section 5.6.10.

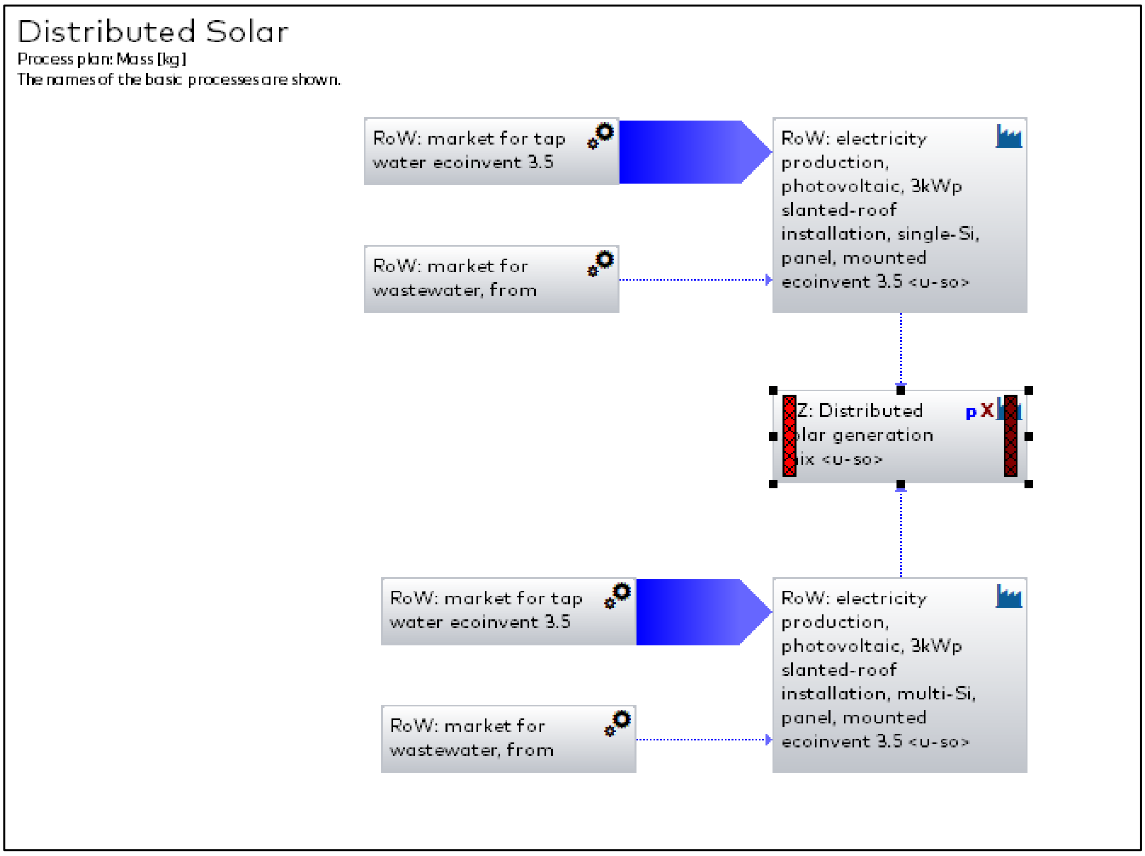

Figure 5.10: Overview of Electricity from Distributed Solar Operation and Maintenance Plan

5.7 Inventory Analysis – Transmission and Distribution

5.7.1 Overview

The T&D model represents the impacts associated with transmission and distribution losses which occur during the transport of electricity between electricity generators and consumers. The T&D model utilises relevant ecoinvent 3.5 datasets supplemented with New Zealand specific data on T&D losses and sulphur hexafluoride (SF_6) use.

All T&D infrastructure inputs are excluded from the relevant datasets as T&D infrastructure impacts are assessed in the separate Infrastructure model (see Section 5.8.7).

The T&D model is made up of two sub-plans: The transmission plan and the distribution plan as shown in Figure 5.11. Specific calculations and information sources are described in Sections 5.7.2 to 5.7.5.

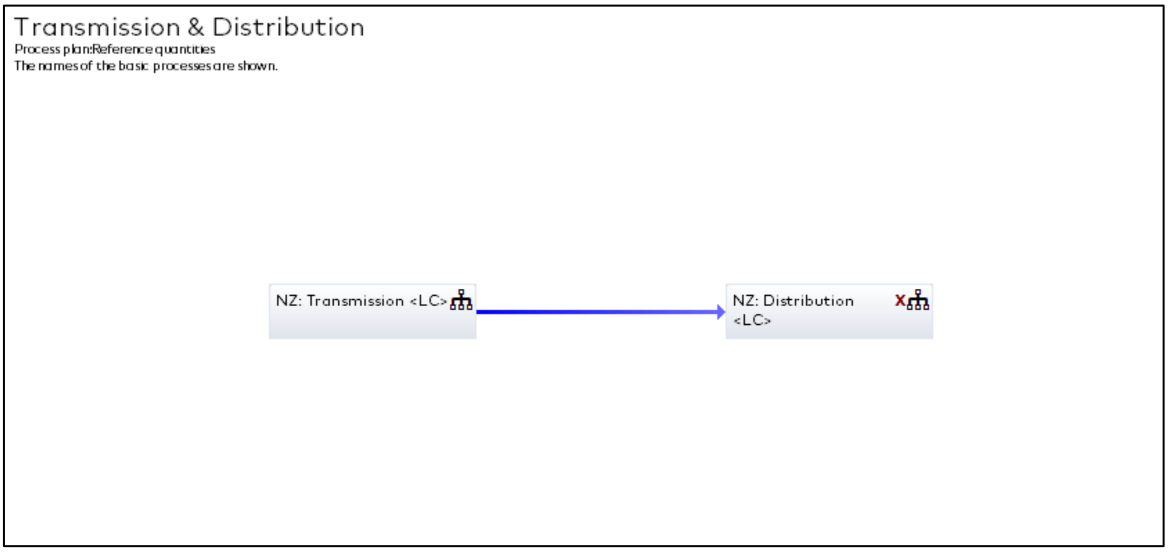

Figure 5.11: Overview of Transmission and Distribution (T&D) Model

5.7.2 Transmission

An overview of the transmission plan is provided in Figure 5.12. This plan includes the following components:

- Market for electricity, high voltage: High voltage electricity supply and transformation from high voltage to medium voltage is represented by an ecoinvent dataset for New Zealand high voltage electricity which incorporates emissions of O_3 and N_2O associated with transmission.
- Market for electricity, medium voltage: Losses during transmission are represented by an ecoinvent dataset for New Zealand medium voltage electricity. This dataset was modified to incorporate a 3.2% loss of generated electricity during transmission (Section 5.7.4) and emissions to air due to losses of SF_6 based on data reported by Transpower (2018b) (Section 5.7.5).
- NZ electricity generation transmission loss: The composition of losses of electricity during transmission is represented by a replication of the O&M plans for the different generation technologies (Section 5.6), excluding distributed solar generation, combined with a parameter based generation mix process which specifies the generation mix for each scenario and year. The transmission loss mix is assumed to be the same as the overall generation mix for each scenario and year.

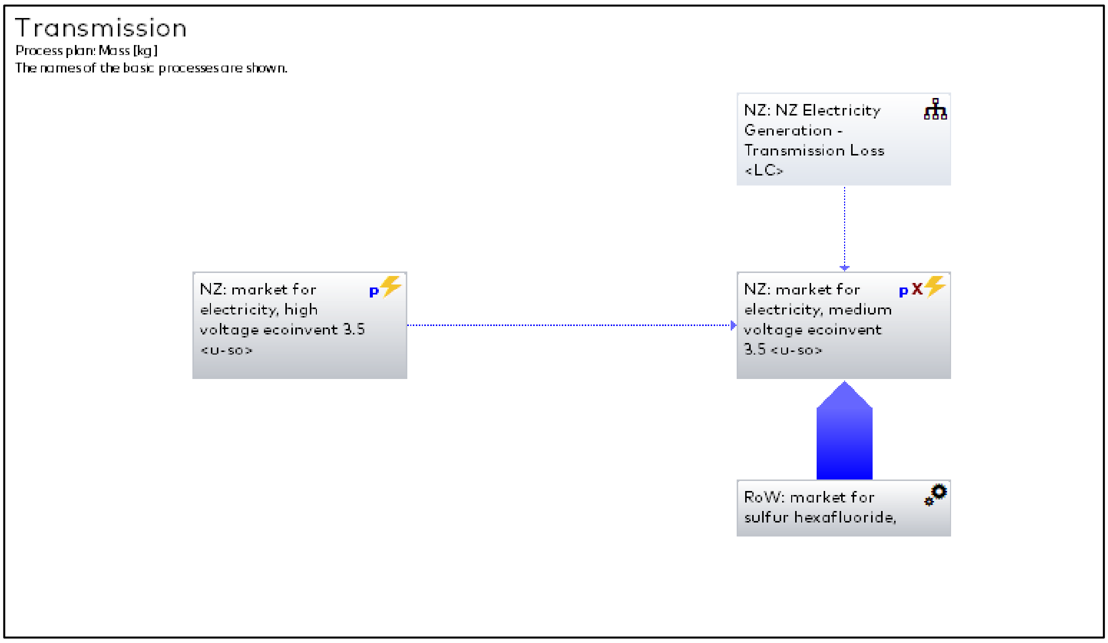

Figure 5.12: Overview of Transmission Plan

5.7.3 Distribution

An overview of the distribution plan is provided in Figure 5.13. This plan includes the following components:

- Market for electricity, low voltage: Low voltage electricity supply and transformation from medium voltage to low voltage is represented by an ecoinvent dataset for New Zealand low voltage electricity which incorporates 3.7% loss of generated electricity during distribution (Section 5.7.4) and emissions to air due to losses of SF_6 from switch-gear during distribution based on historical losses (Section 5.7.5).
- NZ electricity generation distribution loss: The composition of losses of electricity during distribution is represented by a replication of the O&M plans for the different generation technologies (see Section 5.6), excluding distributed solar generation, combined with a parameter based generation mix process which specifies the generation mix for each scenario and year. The distribution loss mix is assumed to be the same as the overall generation mix for each scenario and year.

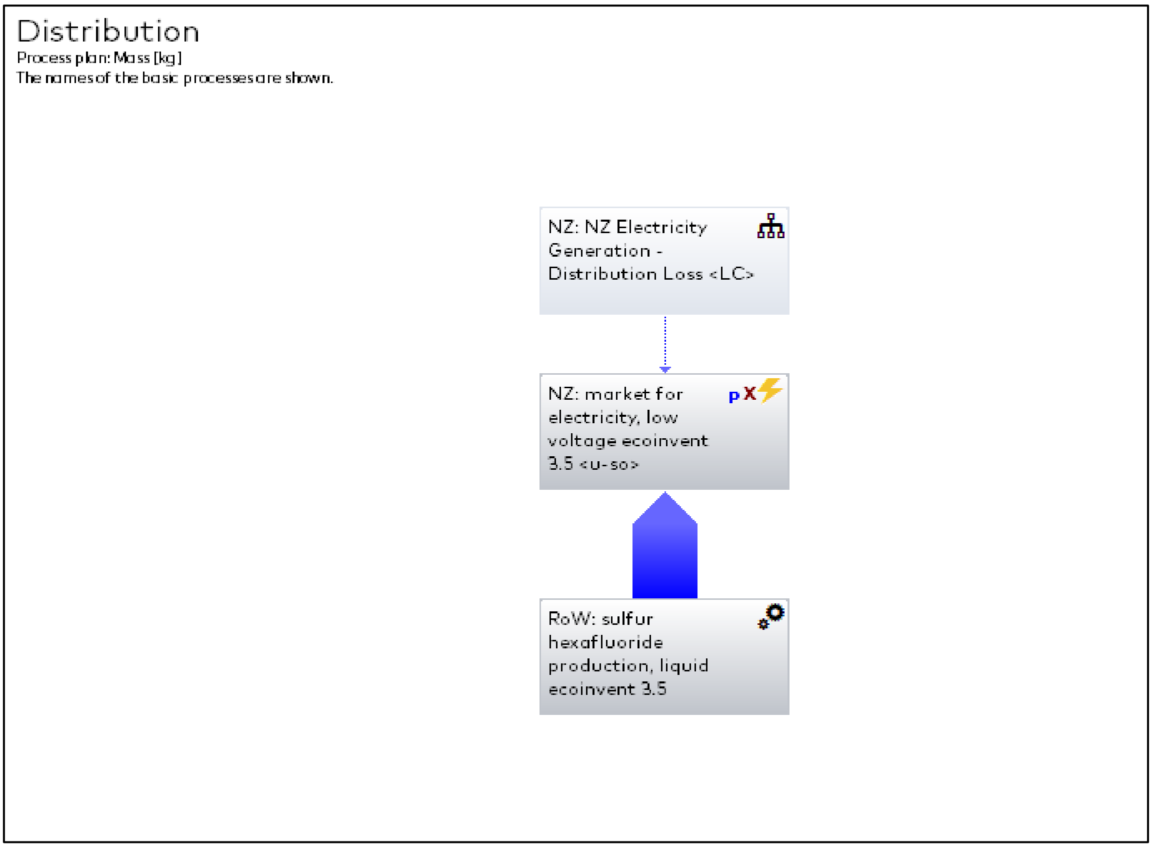

Figure 5.13: Overview of Distribution Plan

5.7.4 Electricity Losses during Transmission and Distribution

Electricity losses occur as electricity is transmitted over the transmission and distribution network due to the heat loss that occurs when electric current flows through a resistance. These losses are estimated on an annual basis by MBIE (2020a) (Appendix F). Estimates of transmission and distribution losses as a percentage of total generation for the five years from 2015 to 2019 are presented in Table 5.13. Based on historical performance, transmission losses were estimated to be 3.2% of total net generation (excluding distributed solar) and distribution losses were estimated to be 3.7% of total net generation (excluding distributed solar) in the T&D model for all future years modelled.

Table 5.13: Electricity Losses 2014-19 as a Percentage of Total Generation
Source: MBIE (2020a)

	2015	2016	2017	2018	2019	Average
Transmission Loss (%)	2.9	3.3	3.2	3.2	3.3	3.2
Distribution Loss (%)	3.9	3.7	3.7	3.7	3.5	3.7
Total Losses (%)	6.8	7.0	6.9	6.9	6.7	6.9

5.7.5 Losses of Sulphur Hexafluoride (SF_6) during Transmission and Distribution

Transpower reported a carbon footprint of SF_6 losses from the New Zealand electricity transmission system of 4,089 tonnes CO_{2eq} during the July 2016 to June 2017 year (Transpower, 2017) and 4,349 tonnes CO_{2eq} during the July 2017 to June 2018 year (Transpower, 2018c). These figures were based on SF_6 emissions having a carbon footprint of 23.5 tonnes of CO_{2eq}/kg (Transpower, 2018b). This equates to losses of SF_6 of 4.08×10^{-9} kg/kWh of generation in 2016/17 and 4.30×10^{-9}kg/kWh in 2017/18 based on the formula below. The average of these two figures (4.19×10^{-9}kg/kWh) is used as an estimate of SF_6 losses from the transmission system in the transmission plan for future electricity generation.

$$SF6\ loss/kWh = \frac{\frac{SF6\ carbon\ footprint\ (tCO2eq)}{23.5\ (tCO2eq)}}{annual\ net\ electricity\ generation\ (kWh)}$$

Losses of SF_6 during distribution were based on the losses from electrical equipment in 2018 reported in the New Zealand GHG Emissions Inventory (MfE, 2020) less the estimated losses from Transpower during the same year using the SF_6 loss/kWh figure calculated above. This resulted in distribution losses of 8.14×10^{-9} kg SF_6/kWh of electricity generated.

5.8 Inventory Analysis – New Build Infrastructure

5.8.1 Overview

The embodied impacts of existing electricity generation, transmission and distribution infrastructure have occurred in the past at the time these facilities were manufactured and constructed. One of the focus areas of this study is an absolute sustainability assessment based on a climate change planetary boundary. Impacts that have occurred in the past are not considered relevant to this type of assessment as it is the actual emissions occurring between the present and a specified future date that are of interest. Accordingly, only the construction impacts associated with new build electricity generation, transmission and distribution infrastructure is considered in this assessment.

The embodied impacts associated with electricity infrastructure generally occur during the manufacturing and construction life-cycle stages which will occur prior to new electricity generation capacity coming online. Therefore, embodied impacts have been allocated to the year prior to the estimated year that new generation capacity will be available under each scenario.

A new build infrastructure plan has been developed for each generation technology that is predicted to increase in capacity under future electricity generation scenarios. The infrastructure plans for gas, wind, utility solar and distributed solar are primarily based on ecoinvent datasets supplemented with New Zealand specific information where relevant. The infrastructure plans for geothermal and hydropower infrastructure are based on relevant LCI data available in published literature supplemented with New Zealand specific information where available.

Impacts and benefits at end of life are not included. The LCI data for geothermal and hydropower infrastructure do not include the end-of-life stages and end-of-life inputs and emissions within the ecoinvent datasets are cut-off by the GaBi attributional modelling approach. The exclusion of end-of-life stages is considered appropriate as the majority of new generation infrastructure constructed during the modelling period will still be in use at the end of the modelling period. Impacts associated with decommissioning of pre-existing electricity generation infrastructure that is scheduled to be decommissioned during the modelling period has also not been considered in this assessment as impacts associated with decommissioning of existing infrastructure is not expected to make a significance contribution to the results.

Maintenance activities during the operational life of the infrastructure are covered by the operation and maintenance model. However, the replacement of significant infrastructure components, specifically replacement of existing transmission and distribution infrastructure (see Section 5.8.7) and geothermal make-up wells (see Section 5.8.3.2), have been included within the infrastructure model.

New generation capacity for coal and biomass is either not anticipated or not considered within the MBIE or ICCC scenarios and therefore no infrastructure models are included for these generation technologies. Infrastructure associated with fuel sourcing (i.e. gas exploration and production; and coal mining) is not primarily associated with electricity generation and is therefore allocated within the operation and maintenance plans on a per kWh basis rather than in the infrastructure plans.

For the BAU scenario used in this study, data on total installed generation capacity by fuel type was provided by the ICCC on an annual basis for all years from 2019 to 2035. Data on total installed generation capacity for the 100% Renewable and Accelerated Electrification scenarios was provided for the 2019 and 2035 years only. The annual new build generation capacity is estimated for the intervening years by assuming that both the generation mix and new build generation capacity increases or decreases on a linear basis between these two years. In reality, changes in capacity would be stepwise in nature as new generation infrastructure is constructed. The annual results for the new build infrastructure for these two scenarios are therefore considered less realistic on a yearly basis than the results for the ICCC BAU and MBIE-forecasted scenarios.

For the ICCC scenarios, the net change in installed generation capacity per year was used to estimate the new build generation capacity per year. This may underestimate the new build capacity as the replacement of existing infrastructure that is decommissioned during the modelling period is not accounted for. Data on generation capacity that is decommissioned during the modelling period is not provided for the ICCC scenarios but is available for the MBIE scenarios. Using the MBIE data on generation capacity decommissioned during 2019-2035 indicates that new gas infrastructure may be underestimated by 43% for the accelerated electrification scenario and 99% for the BAU scenario. There is no new gas generation anticipated for the 100% renewable scenario. The impacts associated with new build gas infrastructure (Section 6.1.2) are very low compared to other generation technologies so this is not anticipated to make a significant impact on the overall results. New geothermal infrastructure may be underestimate by 18-24% and new wind infrastructure by 17-27% with the highest potential underestimation for the BAU scenario.

Figure 5.14 provides an overview of the plans within the Infrastructure Model. Specific assumptions and source information for each component of the model are described in Sections 5.8.2 to 5.8.9.

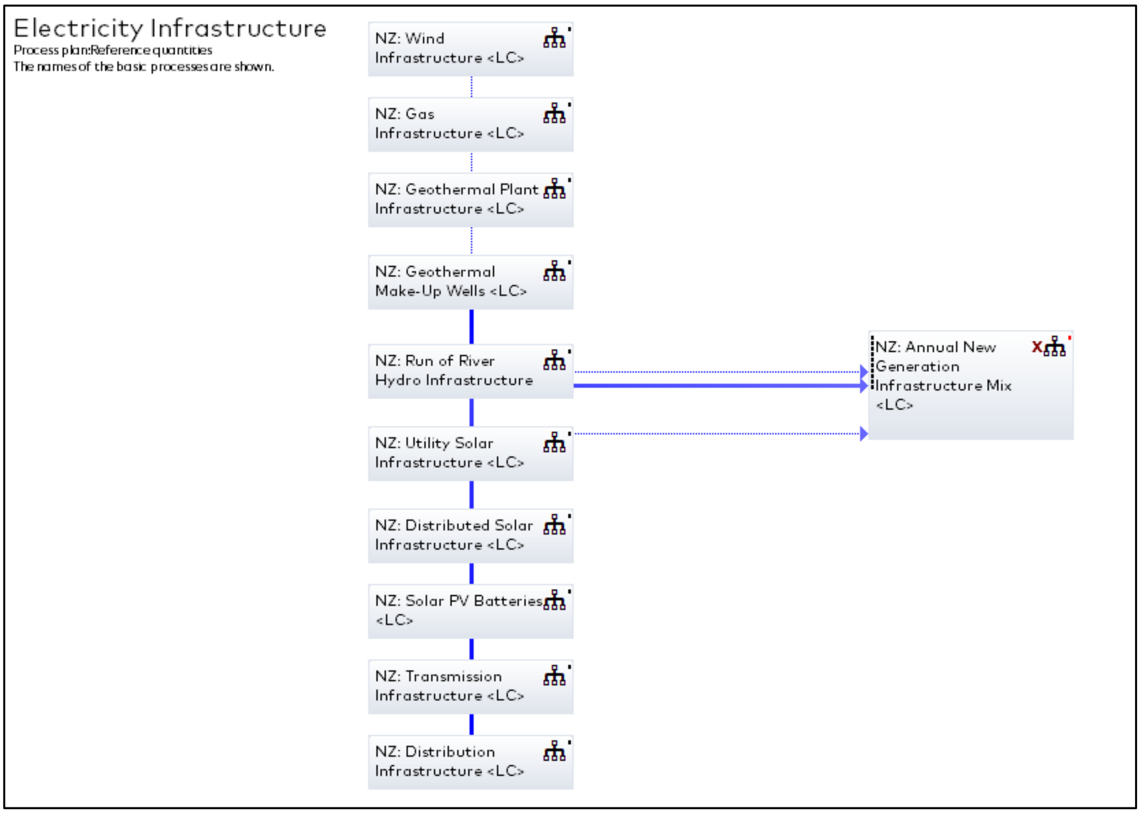

Figure 5.14: Overview of New Build Infrastructure Model

5.8.2 Gas Power Station Infrastructure

An overview of the gas power station infrastructure plan is provided in Figure 5.15. This plan is based on an ecoinvent ‘Rest of World’ process for the construction of a 100 MW gas electrical power plant. It is assumed that the majority of new gas electricity generation would operate in a ‘peaking’ capacity and is therefore represented by an ‘electricity only’ plant.

The ecoinvent dataset is modified with the following New Zealand specific inputs:

- An ecoinvent process for the New Zealand electricity market (medium voltage) is used in place of the default electricity mix.
- The default concrete process is replaced with a New Zealand specific data based on an Environmental Production Declaration (EPD) for 30 MPa Allied Concrete Normal in-situ concrete sourced from New Plymouth (Allied Concrete Ltd, 2019).
- The default process for reinforcing steel is replaced with a New Zealand specific data based on an EPD for steel rod (Pacific Steel (NZ) Ltd, 2018).

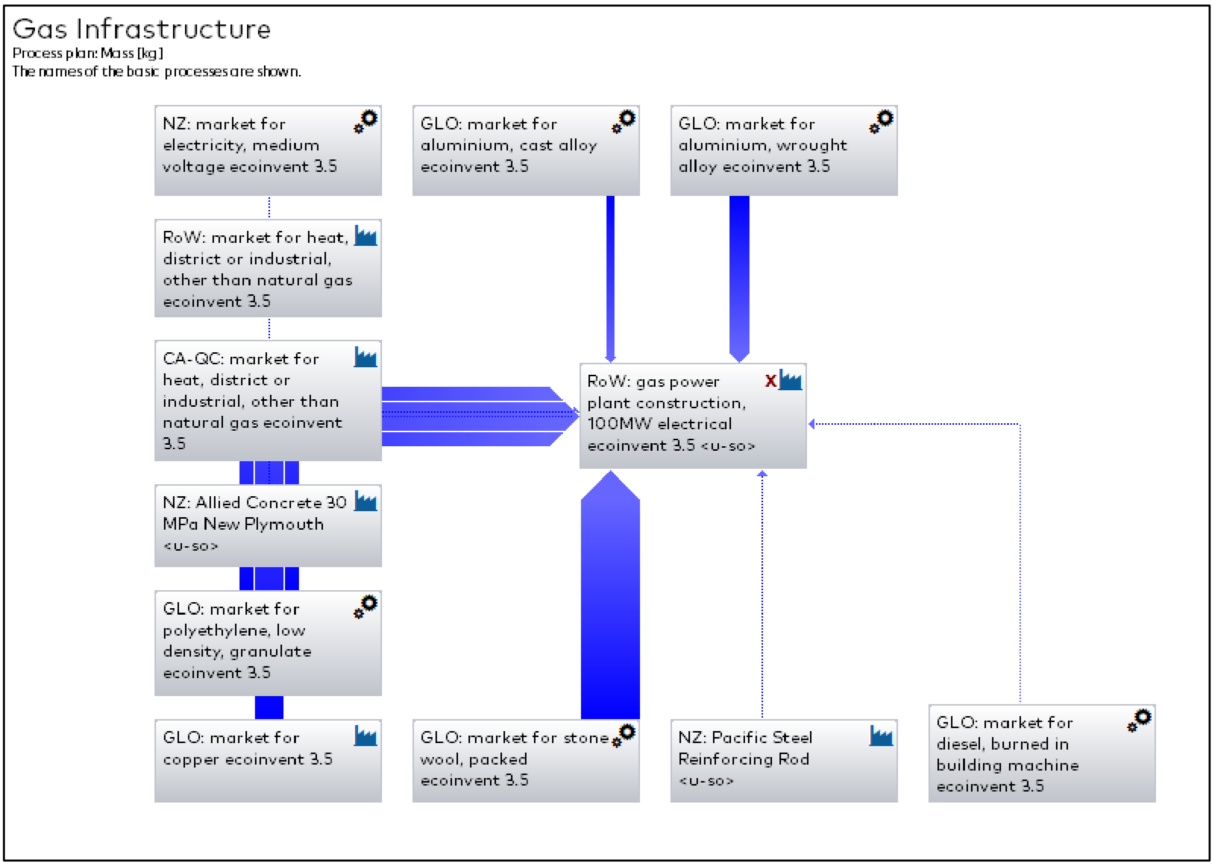

Figure 5.15: Overview of Gas Power Station Infrastructure Plan

5.8.3 Geothermal Infrastructure

Geothermal electricity generation infrastructure is composed of two main components:

- Initial construction of the geothermal power plant facilities including well drilling and casing, collection pipelines, and power plant construction.
- Construction of geothermal make-up wells over the life of the geothermal field to maintain production levels including well drilling and casing, and collection pipeline construction.

These two aspects of geothermal infrastructure including specific assumptions and source information are described in Sections 5.8.3.1 (geothermal power plant) and 5.8.3.2 (geothermal make-up wells) below.

5.8.3.1 Geothermal Power Plant Construction

An overview of the geothermal power plant construction plan is provided in Figure 5.16. The plan includes the following components:

- Well drilling: Steel and diesel required to drill geothermal wells.
- Production well drilling and casing: Materials and resources required for wellhead equipment and well casing.
- Collection pipelines: Materials and resources required to construct collection pipelines between the geothermal wells and geothermal power plant.
- 2-Flash power plant building: Materials and resources required to construct the power plant building. A 2-flash power plant to represent New Zealand geothermal electricity

production as this technology makes up the greatest proportion of existing New Zealand geothermal generation (Saçayon Madrigal, 2015).
- <u>2-Flash power plant machinery</u>: Material and resources required for manufacture and installation of geothermal production equipment.

The geothermal power plant construction plan is based on LCI data representing an 80 MW New Zealand geothermal plant developed by Saçayon Madrigal (2015) which utilised LCI data calculated for the 303 MW Hellisheidi geothermal plant in Iceland (Karlsdóttir et al., 2015) with the material and resources required scaled to reflect the number and depth of wells drilled, size of power plant and length of collection pipelines for a typical New Zealand geothermal power plant. These assumptions are updated for this study based on advice from a New Zealand geothermal expert. A summary of the main assumptions is provided in Table 5.14.

The ecoinvent datasets utilised by Saçayon Madrigal (2015) are modified with the following New Zealand specific inputs where relevant:

- An ecoinvent process for the New Zealand electricity market (medium voltage) is used in place of default electricity mixes;
- The default concrete process is replaced with New Zealand specific data for in-situ Normal concrete based on EPD data for 30 MPa concrete sourced from Taupo (Allied Concrete Ltd, 2019).
- The default cement process is replaced with New Zealand specific data based on EPDs for cement from Golden Bay Cement (2019) and Holcim (NZ) Ltd (2019) assuming an equal 1:1 mix of cement from these two New Zealand suppliers.

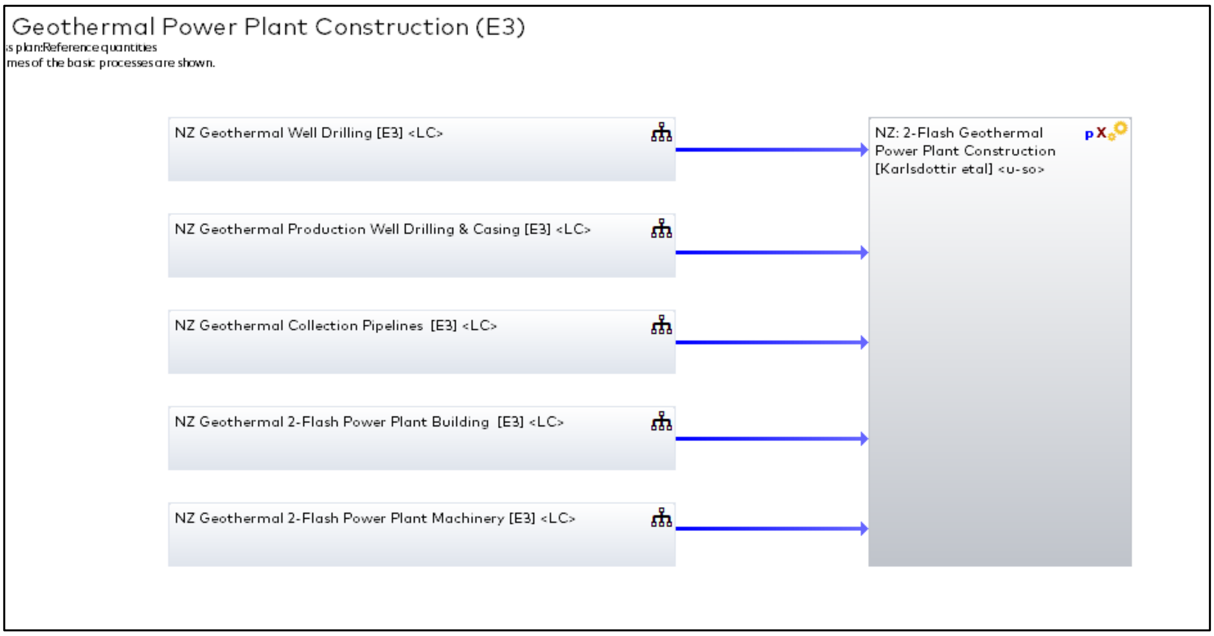

Figure 5.16: Overview of Geothermal Power Plant Infrastructure Plan

Table 5.14: Assumptions for New Zealand Geothermal Power Plant Infrastructure Plan

Component	Assumption	Source
Output per geothermal production well	4 MW	White (2019)
Number of reinjection wells required	1 reinjection well per 2 production wells	White (2019)
Initial number of wells required for 80 MW plant	20 production wells 10 reinjection wells	White (2019)
Average depth of geothermal well (production and re-injection)	2,000 m	White (2019)
Average length of collection pipeline	3,000 m	Saçayon Madrigal (2015)
Average number of collection pipelines per geothermal plant	10	Saçayon Madrigal (2015)

5.8.3.2 Geothermal Make-up Wells

Geothermal make-up wells are required to be constructed over the life of a geothermal field to maintain production levels. The geothermal make-up plan is composed of the well drilling, well drilling and casing, and collection pipeline components of the geothermal power plant construction plan as described in Section 5.8.3.1. An overview of the geothermal make-up well plan is provided in Figure 5.17. Based on advice from a New Zealand geothermal expert (White, 2019) it is assumed that, on average, additional make-up wells will be constructed at a rate of 3% of the initial number of production wells per year. For example, an 80 MW geothermal plant requiring 20 initial production wells will need an additional 3 make-up wells every 5 years on average. In this assessment, the requirement for make-up wells is applied to the total predicted geothermal capacity for each scenario as the requirement for make-up wells will apply to both existing geothermal capacity and new build geothermal generation.

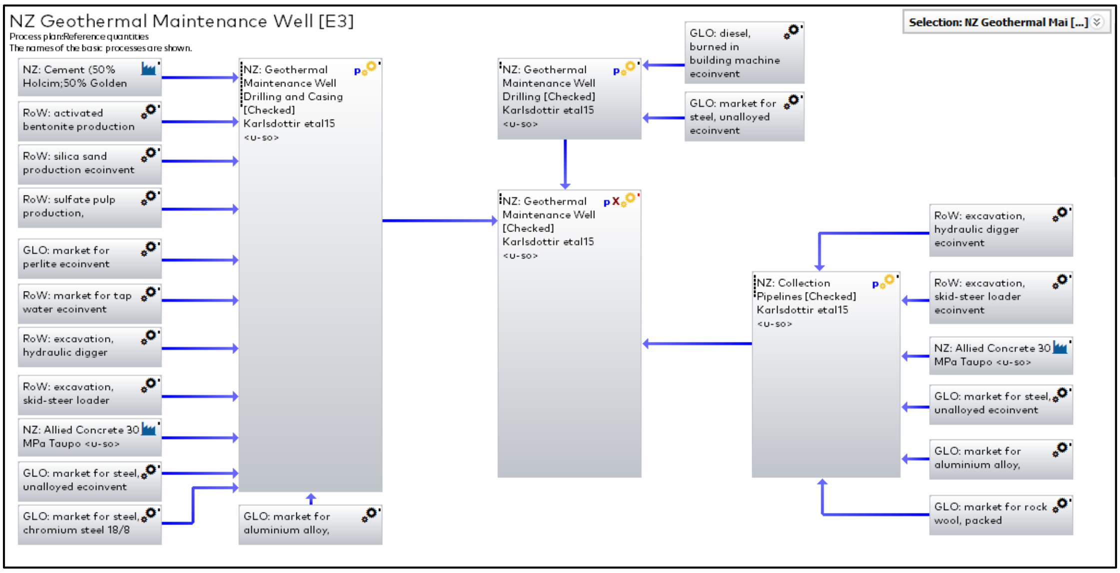

Figure 5.17: Overview of Geothermal Make-up Well Infrastructure Plan

5.8.4 Hydropower Infrastructure

An overview of the hydropower plant infrastructure plan is provided in Figure 5.18.

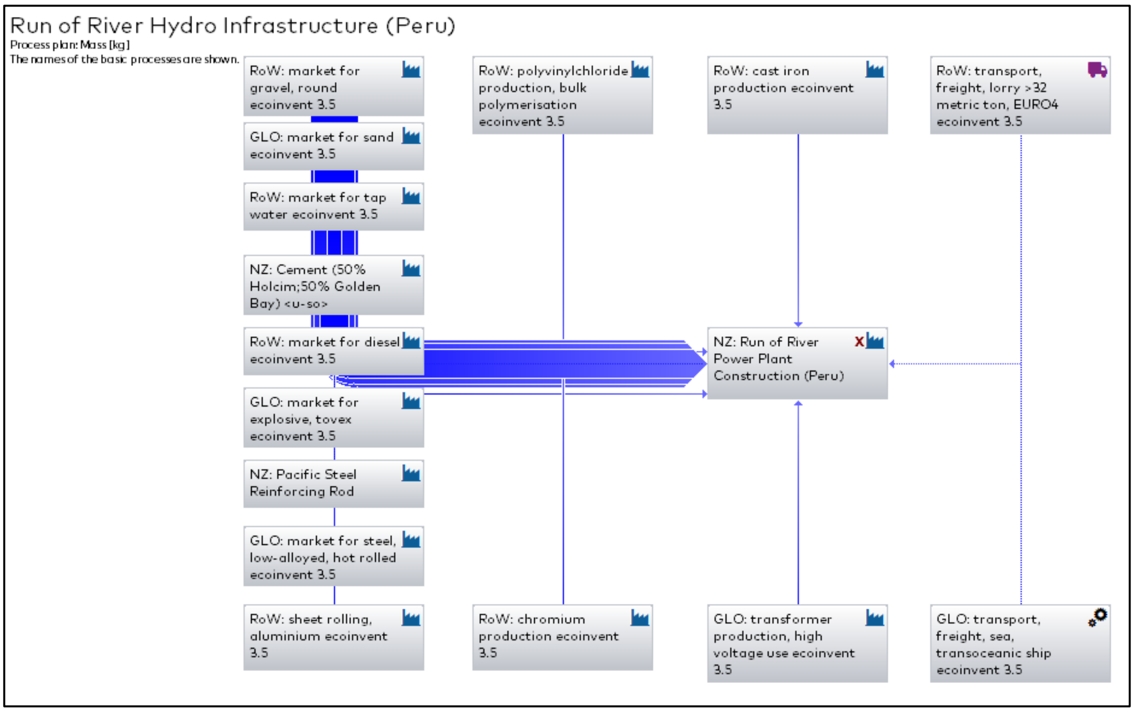

Figure 5.18: Overview of Hydropower Infrastructure Plan

The hydropower infrastructure plan is based on LCI data for two Peruvian run-of-river hydropower plants located in the Andean mountains (Verán-Leigh & Vázquez-Rowe, 2019). Run-of-river hydropower plants are selected to represent new-build hydropower generation in New Zealand due to the likely public opposition to new reservoir hydropower plants. The two run-of-river hydropower plants (H1 and H2) used as the basis for New Zealand hydropower infrastructure have installed capacities of 178 MW and 220 MW respectively. LCI data related to the construction and manufacturing life-cycle stages for these two hydropower plants are presented in Table 5.15. The average of each input was calculated and used to represent a 199 MW run-of-river hydropower plant constructed in New Zealand.

Verán-Leigh and Vázquez-Rowe (2019) reported a single category for steel. For the purposes of the hydropower infrastructure plan this is separated into reinforcing steel and hot rolled steel in the same proportions as the default ecoinvent dataset for run-of-river hydropower construction in Switzerland (see Table 5.15).

Ecoinvent 'Global' or 'Rest of World' datasets are used to represent most inputs except for the following where New Zealand specific data is used:

- Cement is based on New Zealand specific EPD data for cement from Golden Bay Cement (2019)and Holcim (NZ) Ltd (2019) assuming an equal 1:1 mix of cement from these two New Zealand suppliers.
- Reinforcing steel is based on New Zealand specific EPD data for steel rod (Pacific Steel (NZ) Ltd, 2018).

Table 5.15: LCI Data Used in NZ Hydropower Infrastructure Plan Source: Verán-Leigh and Vázquez-Rowe (2019)

	Unit	H1 (Peru)	H2 (Peru)	Average Value used in NZ Hydropower Infrastructure Plan
Installed capacity	MW	178	200	199
Inputs from the Environment				
Gravel	t	$8.51x10^{+4}$	$1.74x10^{+5}$	$1.29x10^{+5}$
Sand	t	$7.7x10^{+4}$	$1.49x10^{+5}$	$1.33x10^{+5}$
Water	m^3	$2.53x10^{+4}$	$4.85x10^{+4}$	$3.69x10^{+4}$
Inputs from the Technosphere (materials)				
Cement	t	$5.61x10^{+4}$	$1.02x10^{+5}$	$7.91x10^{+4}$
Diesel	t	567	763	665
Explosives		538	233	385.5
Steel	t	$5.69x10^{+3}$	$9.16x10^{+3}$	
Reinforcing steel	t	-		$1.93x10^{+3}$
Hot-rolled steel	t	-		$5.49x10^{+3}$
Polyvinylchloride (PVC)	t	5.89	6.0	5.95
Aluminium	t	543	263	403
Iron	t	12.3	12.3	12.3
Chromium	t	2.0	2.67	2.34
Transformer	t	971	970	970.5
Inputs from the Technosphere (transport)				
Truck transport	t km	$1.67x10^{+7}$	$2.3x10^{+7}$	$1.99x10^{+7}$
Transoceanic ship	t km	$1.76x10^{+7}$	$1.25x10^{+7}$	$1.51x10^{+7}$

5.8.5 Wind Power Infrastructure

An overview of the wind power infrastructure plan is provided in Figure 5.19. This plan is based on ecoinvent ‘Global’ processes for the onshore construction of a 4.5 MW wind turbine and a 4.5 MW wind network connection. A 4.5 MW turbine was selected as representative of new build wind infrastructure as New Zealand is expected to follow international trends towards installing wind turbines of larger capacity (see Section 5.6.6).

The ecoinvent datasets are modified with the following New Zealand specific inputs:

- The default concrete process within the wind network connection plan is replaced with a New Zealand specific concrete process based on EPD data for 30MPa Normal in-situ concrete supplied by Allied Concrete sourced from Palmerston North (Allied Concrete Ltd, 2019).
- A transoceanic ship transport distance of 5.66x10^{+6} t km is used to represent the transport of a 440 t wind turbine (based on a Vestas V120-4.5 turbine) 12,850 km from the port of Tianjin in China to Auckland, New Zealand.
- A freight truck transport distance of 88,000 t km is used to represent the transport of a 440 t wind turbine a nominal distance of 200 km from Auckland to a wind farm site.

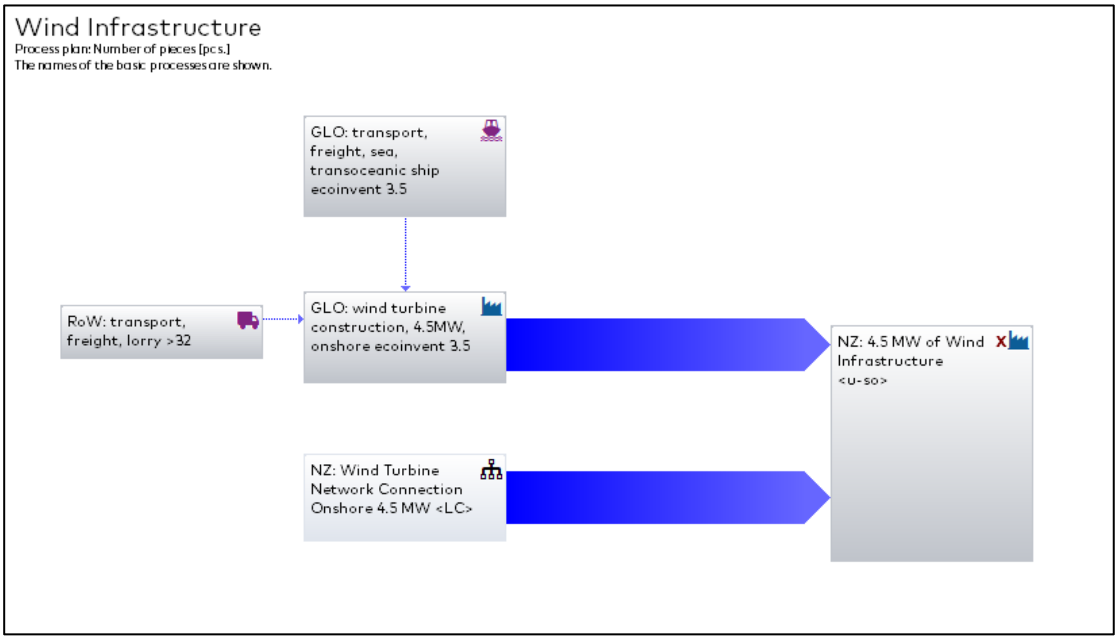

Figure 5.19: Overview of Wind Infrastructure Plan

5.8.6 Utility Solar Infrastructure

An overview of the utility solar infrastructure plan is provided in Figure 5.20. This plan is based on an ecoinvent process for the construction of a concentrated solar tower power plant in South Africa. There were no modifications made to this ecoinvent process.

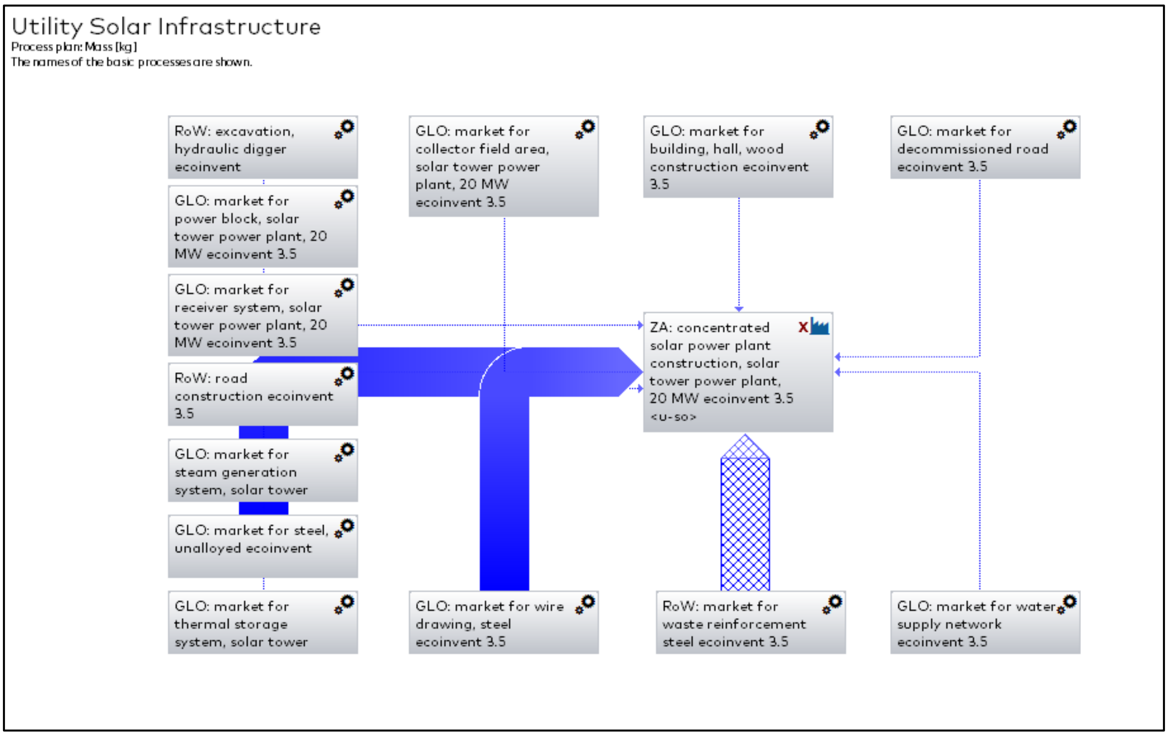

Figure 5.20: Overview of Utility Solar Infrastructure Plan

5.8.7 Transmission and Distribution Infrastructure

Transpower and electricity distribution companies publish information on future plans for replacement and new build transmission and distribution infrastructure through the Transpower Transmission Planning Reports (Transpower, 2019c) and Asset Management Plans produced by electricity distributors. This information is not in a format which can be easily converted into LCI data due to the absence of specific quantities of materials or lengths of new transmission or distribution lines to be built. Therefore, an approximation for replacement and new build transmission and distribution infrastructure is made for the purposes of this study.

Ecoinvent datasets for transmission and distribution network construction in Switzerland are used to represent the replacement of existing infrastructure and construction of new infrastructure in New Zealand. These datasets represent the construction of transmission or distribution network infrastructure per km of network constructed including inputs such as poles, cables, buildings and SF_6 inventory in switching stations. Transpower operates 11,200 km (Transpower, 2019b) of transmission lines and the 32 New Zealand distribution companies operate approximately 155,000 km of distribution lines (Commerce Commission, 2020).

Transpower (2019a) estimates the average useful life of transmission assets as follows:

- HVAC transmission lines - 58 years;
- HVAC transmission high voltage cables - 45 years;
- HVAC transmission lines (tower painting) - 15 years;
- HVAC substations - 43 years;
- HVDC substations (including submarine cables) - 28 years; and
- HVDC transmission lines - 55 years.

Based on the above estimates, this study has assumed a replacement life of 50 years for both distribution and transmission infrastructure which equates to replacement of 2% of the existing infrastructure per year. In addition, it is assumed that the amount of new build transmission and distribution infrastructure each year is equivalent to 1% of the currently existing infrastructure. A total of 3% of the existing infrastructure is allocated to the replacement and new build of infrastructure each year. The resulting lengths of transmission or distribution line per year are presented in Table 5.16.

These lengths are used in conjunction with the relevant ecoinvent datasets to estimate the annual impacts associated with transmission and distribution infrastructure. Due to the estimated nature of these figures there is no differentiation between years or scenario in terms of transmission or distribution infrastructure.

Table 5.16: Estimates of Replacement & New Build Transmission and Distribution Infrastructure

	Length of Existing Lines (km)	Length of Replacement Line - 2% of existing line length (km/year)	Length of New Build Line – 1% of Existing Line Length (km/year)	Total Length of New and Replacement Line (km/year)
Transmission Infrastructure	11,200	224	112	336
Distribution Infrastructure	150,000	3,100	1,550	4,650

5.8.8 Distributed Solar Infrastructure

Distributed solar generation infrastructure is composed of both the construction of roof-top solar PV panels and the installation of batteries for a proportion of PV solar systems.

An overview of the distributed solar infrastructure plan is provided in Figure 5.21. This plan is based on ecoinvent ‘Rest of World’ processes for multi-Si and single-Si roof mounted PV panels. It is assumed that 50% of newly installed panels are multi-Si and 50% are single-Si panels consistent with the assumptions made for the O&M of distributed solar generation (see Section 5.6.12). The only modification to the ecoinvent datasets is the replacement of default electricity mixes with the ecoinvent low voltage electricity process for New Zealand.

The use of batteries with distributed solar systems is represented by an ecoinvent global dataset for rechargeable Li-ion batteries with no modifications made. The number of distributed solar systems with batteries is based on projections of the number of solar systems with batteries for each of the five MBIE Scenarios (MBIE, 2019g). For the ICCC Scenarios, it was assumed that the same proportion of distributed solar systems would utilise batteries as projected for the MBIE Reference Scenario. It is assumed that each battery comprises 4 kg of Li-ion batteries and that this is equivalent to 8.4 kWh of battery storage per installation.

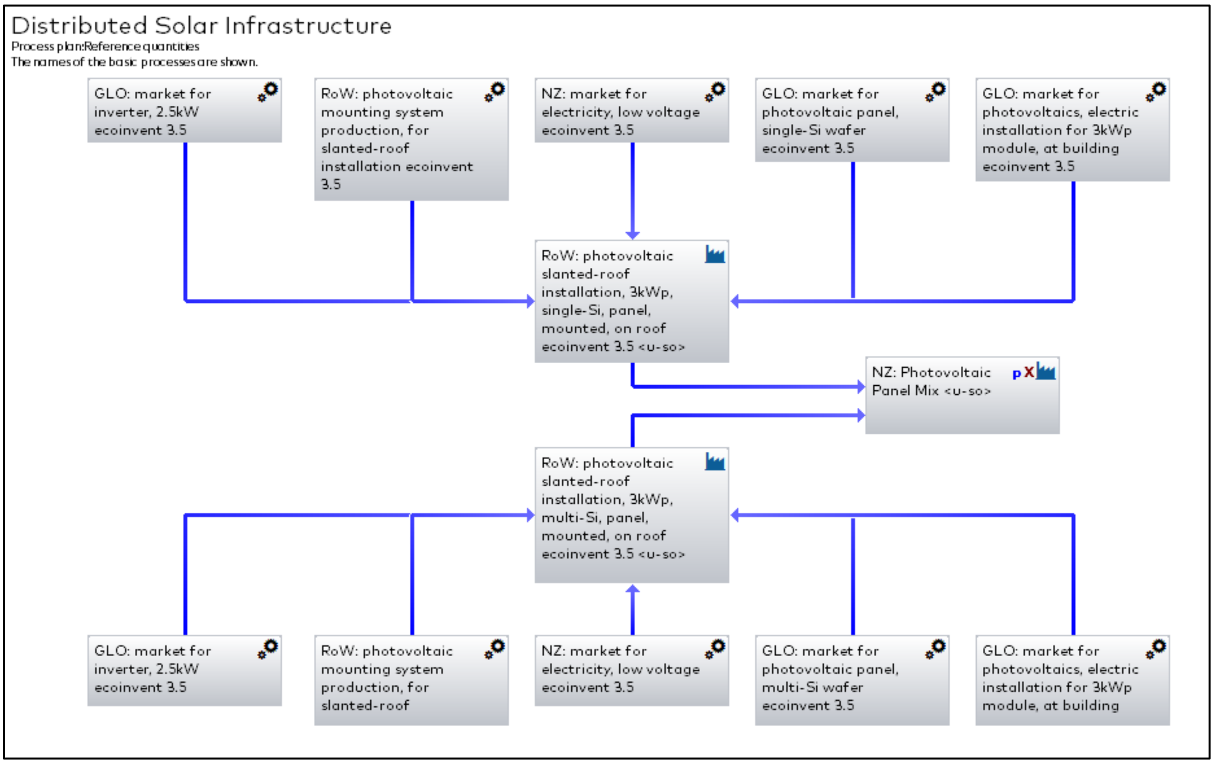

Figure 5.21: Overview of Distributed Solar Infrastructure Plan

5.8.9 New Build Infrastructure Mix

The annual new build infrastructure mix plan incorporates the predicted new capacity mix for each of the eight scenarios on an annual basis. The parameter explorer function of GaBi is used to establish a scenario group for each of the MBIE and ICCC scenarios and an individual scenario for each year covered by the scenario. Scenarios are also established for 1 MW of new generation for each technology.

The new build infrastructure mix plan links to each of the individual generation technology infrastructure plans to allocate an appropriate amount of new generation capacity for each generation type to each year and scenario.

5.9 Limitations

There are a number of assumptions and approximations inherent within the models of future New Zealand electricity generation and supply described in Sections 5.6, 5.7 and 5.8. Many of these assumptions and approximations are based on current data or data from recent history but may not necessarily apply in future. This is an unavoidable limitation of this assessment. Sections 5.9.1 to 5.9.4 provide a brief discussion of the main types of limitations within the future New Zealand electricity models.

The MBIE and ICCC Scenarios which form the basis of the assessment also incorporate several assumptions regarding future conditions. One of the purposes of using a scenario-based approach is to consider a range of possible future conditions given the inherent difficulties of predicting future behaviour or conditions. A summary of key assumptions within the MBIE and ICCC scenarios are contained in Appendix B.

5.9.1 Future Changes in Technology

The models of future electricity generation and supply are predominantly based on current electricity generation technology in New Zealand in terms of types of technology, efficiency, operational practices, inputs and emissions. Changes in technology and operational practices will inevitably occur over the time period covered by the scenarios. This is especially true for relatively new and rapidly evolving technologies such as wind and solar power. In addition, as older infrastructure is retired and new infrastructure is commissioned, the average age of each type of generation infrastructure will change over time. Although reduced utilisation of some fixed assets may result in decreased efficiencies, it is anticipated that overall, these changes will result in greater efficiency and lower emissions, and therefore the actual future impacts may be lower than predicted by the models.

5.9.2 Excluded or Simplified Processes

Electricity generation and supply is a complex process with many different interconnected components and variables. Modelling of a complex system such as this requires a level of simplification due to limitations of time, resources and data. Several aspects of the electricity system which may affect the resulting impacts have been excluded from this assessment. This includes:

- Future generation from waste heat and other minor generation technologies (e.g. small scale hydropower);
- Decommissioning of existing generation capacity which may be retired during the modelling period.

There are also several simplifications of the electricity system which have been adopted as part of the modelling process. In particular:

- The allocation of gas and coal fired cogeneration emissions is based on emissions from electricity only plants (see Sections 5.6.2.3 and 6.4.2).
- Calculation of new build infrastructure for the ICCC scenarios is based on net changes in total generation capacity and does not account for replacement of existing generation capacity decommissioned during the modelling period.
- New build and replacement transmission and distribution infrastructure is estimated based on the amount of existing infrastructure, its estimated useful life and a nominal percentage increase of 1% of the existing infrastructure each year.
- Transmission and distribution losses are applied to all generation except for distributed solar ignoring the use of electricity by auto-producers (i.e. where electricity is generated and used at the same site) and some industrial users that utilise medium voltage electricity.
- Assumptions regarding generation technology do not fully represent the diversity of generation technology within each fuel type (e.g. NGCC and 2-Flash geothermal plants are used to represent all types of gas and geothermal generation).

5.9.3 Lack of New Zealand Specific Data

Due to the absence of New Zealand specific data, many of the processes represented within the models are based on global ecoinvent datasets or data from literature which may not accurately represent the New Zealand context or the resulting impacts. For example, the emission of GHGs from hydropower reservoirs has been shown to be highly variable depending on climate, existing land use, depth of reservoir and geology (Deemer et al., 2016) however no

New Zealand specific studies on this topic have been identified and default ecoinvent emissions have been adopted.

5.9.4 Changes in Background Conditions

The electricity system is influenced by conditions outside of the system itself such as climatic, economic and regulatory conditions. Changes in climatic conditions over the modelling period may particularly affect the efficiency of production from renewable technologies due to changes in rainfall, wind or solar radiation associated with climate change.

Several potential economic variables are considered within the different scenarios such as different levels of economic growth and the marginal cost of new capacity for different generation technologies. Economic changes may also potentially influence the inputs or emissions of different generation technologies. For example, lower profits may discourage the adoption of emission abatement technology or lower demand for coal from other sectors may reduce the proportion of imported coal used for electricity generation.

Changes in the regulatory environment may also influence the impacts associated with different generation technologies. For example, regulations requiring more stringent emissions control may reduce emissions associated with fossil fuel or geothermal generation.

5.10 Calculation of Planetary Boundaries for New Zealand Electricity

One of the research questions for this study (Section 1.2) is whether increased renewable electricity generation in New Zealand is compatible with a 1.5°C climate target. In order to address this question, climate change planetary boundaries (PBs) (Section 4.5) for New Zealand electricity supply from 2018 to 2050 were calculated using different sharing principles and carbon budgets (CBs).

Global and New Zealand Carbon Budget

A global CB from 2018 to 2050 of 786 $GtCO_{2eq}$, representing a 1.5°C limit to global warming by 2050, was adopted based on studies by Rogelj et al. (2015) and Chandrakumar et al. (2020). A New Zealand CB from 2018 to 2050 was then calculated based on both economic and equal per capita sharing.

Economic sharing was calculated based on 2017 data of New Zealand gross value added (GVA) production as a proportion of global GVA production (World Bank, 2019) using the following formula.

$$NZ\ CB, Economic = \frac{GVA, NZ, 2017}{GVA, Global, 2017}\ x\ Global\ CB$$

Equal per capita sharing was calculated from the New Zealand population between 2018 and 2050 as a proportion of the global population between 2018 and 2050 according to the following formula:

$$NZ\ CB, Per\ Capita = \frac{Population, NZ}{Polulation, Global}\ x\ Global\ CB$$

Downscaling the Economic Based New Zealand Carbon Budget

When downscaling the New Zealand CB based on economic sharing to a New Zealand electricity CB, both economic and grandfathering sharing principles were used. Economic sharing was calculated according to the gross domestic product (GDP) of electricity as a proportion of total New Zealand GDP for the year ending March 2017 according to the following formula:

$$Electricity\ CB, Economic\&Economic = \frac{GDP, electricity, 2017}{GDP, NZ, 2017}\ x\ NZ\ CB$$

New Zealand GDP figures were only available for the electricity and gas sectors combined. The electricity component was estimated to be 85% of the total GDP for the electricity and gas sector based on the annual energy balance for 2017 (MBIE, 2018) and energy prices for 2017 (MBIE, 2020b).

Downscaling the New Zealand CB based on economic sharing to a New Zealand electricity CB based on grandfathering was calculated from the carbon footprint of New Zealand electricity generation plus T&D in 2016 as a proportion of the New Zealand production based carbon footprint (MfE, 2019b) for the year 2016 according to the following formula:

$$Electricity\ CB, Economic\&Grandfather = \frac{CF, Electricity, 2016}{CF, NZ\ Production, 2016}\ x\ NZ\ CB$$

It is noted that the two methods of downscaling the Zealand CB based on economic sharing to a New Zealand electricity CB result in quite different CBs for electricity. Economic sharing of the New Zealand CB reflects the relatively low value of electricity compared to total New Zealand GDP whereas grandfathering reflects that a relatively high proportion of the total New Zealand production based GHG emissions are due to electricity (Table 5.17).

Downscaling the Equal per Capita Based New Zealand Carbon Budget

The New Zealand CB based on equal per capita sharing was downscaled to a New Zealand electricity CB using a grandfathering approach. This was calculated from the carbon footprint of New Zealand electricity generation plus T&D in 2011 as a proportion of the New Zealand consumption based carbon footprint for the year 2011 (Chandrakumar et al., 2020) according to the following formula:

$$Electricity\ CB, PerCapita\&Grandfather = \frac{CF, Electricity, 2011}{CF, NZ\ Consumption, 2011}\ x\ NZ\ CB$$

Calculation of Historical Impacts using Grandfathering

The carbon footprints of New Zealand electricity in 2016 and 2011, for the purposes of grandfathering, were calculated using an adapted version of the model developed in this thesis but with the impacts of generation infrastructure allocated evenly to each year in the lifetime of each generation technology rather than totally allocated to the year of construction. The years 2016 and 2011 were selected as the base years for grandfathering due to the availability of suitable datasets of total New Zealand production based (MfE, 2019b) and consumption based (Chandrakumar et al., 2020) GHG emissions respectively.

Summary of Calculated Carbon Budgets

The resulting total New Zealand CBs and New Zealand electricity sector CBs for 2018-2050 for each of the above combinations of sharing principles are shown in Table 5.17.

Table 5.17: Summary of New Zealand and Electricity Sector Carbon Budgets 2018-2050

Global Carbon Budget 2018-2050 (GtCO$_{2eq}$)	Sharing Principal for NZ Carbon Budget	New Zealand Carbon Budget 2018-2050 (Gt CO$_{2eq}$)	Sharing Principle for NZ Electricity Sector Carbon Budget	NZ Electricity Sector Carbon Budget 2018-2050 (Gt CO$_{2eq}$)
786	Economic - GVA	1.827	Economic/GDP – production based	0.037
			Grandfather – production based	0.134
	Equal per Capita	0.474	Grandfather-consumption based	0.048

6 Life Cycle Assessment of Future New Zealand Electricity Supply: Impact Assessment

6.1 Contribution to Impacts from Each Generation Technology

6.1.1 Operational Impacts Per kWh

The operation and maintenance (O&M) model is comprised of separate plans for each generation technology. Similarly, the transmission and distribution (T&D) model utilises the O&M plans for each generation technology to represent the losses of electricity occurring during T&D. The sum of the impacts from the O&M and T&D models represent the operational impacts associated with the generation and supply of electricity. Figure 6.1 and Figure 6.2 presents the operational impacts of 1 kWh of electricity for each generation technology (Appendix H).

On a per kWh basis, either coal or biomass has the highest operational impacts for each indicator. Electricity from coal has the highest impacts per kWh for the climate change indicators (GWP_{100}, GWP_{100} excl biogenic, GTP_{100}), ADP fossil, EP, AP and PED non-renewable. Electricity from biomass has the highest impacts for ADP elements, ODP, POCP, PED renewable and PED total.

The impacts from coal are significantly higher than all other generation types for the climate change, ADP fossil, EP, AP and PED non-renewable indicators.

In terms of the climate change metrics, the impacts per kWh of electricity from coal are more than double the impacts from gas which has the second highest impacts. Combustion of coal at power stations accounts for 94% of the coal O&M impacts and combustion of gas accounts for 88% of gas O&M impacts.

In terms of electricity from biomass, the supply of wood chips to the cogeneration plant is the main life cycle stage contributing to the ADP elements (95%), ODP (98%), PED renewable (100%) and PED total (99.9%) indicators. Operation of the cogeneration plant is the main life cycle stage contributing to POCP (72%) and EP (67%) impacts.

Hydropower, wind, utility solar and distributed solar generally have very low operational impacts compared to electricity from coal, gas and biomass in all indicators except ODP (and, obviously, PED renewable). Utility solar has slightly higher ODP impacts than gas generation largely arising from the input of heat from natural gas in the ecoinvent dataset for utility solar. There are currently no utility solar plants operating in New Zealand, but future plants could potentially use an alternative source to natural gas (e.g. grid electricity).

Electricity from geothermal generally has relatively low impacts compared to coal, gas and biomass but higher impacts than the other renewable generation technologies for the climate change and AP indicators. The impacts of electricity from geothermal were comparable to the other renewable generation technologies for the remaining indicators.

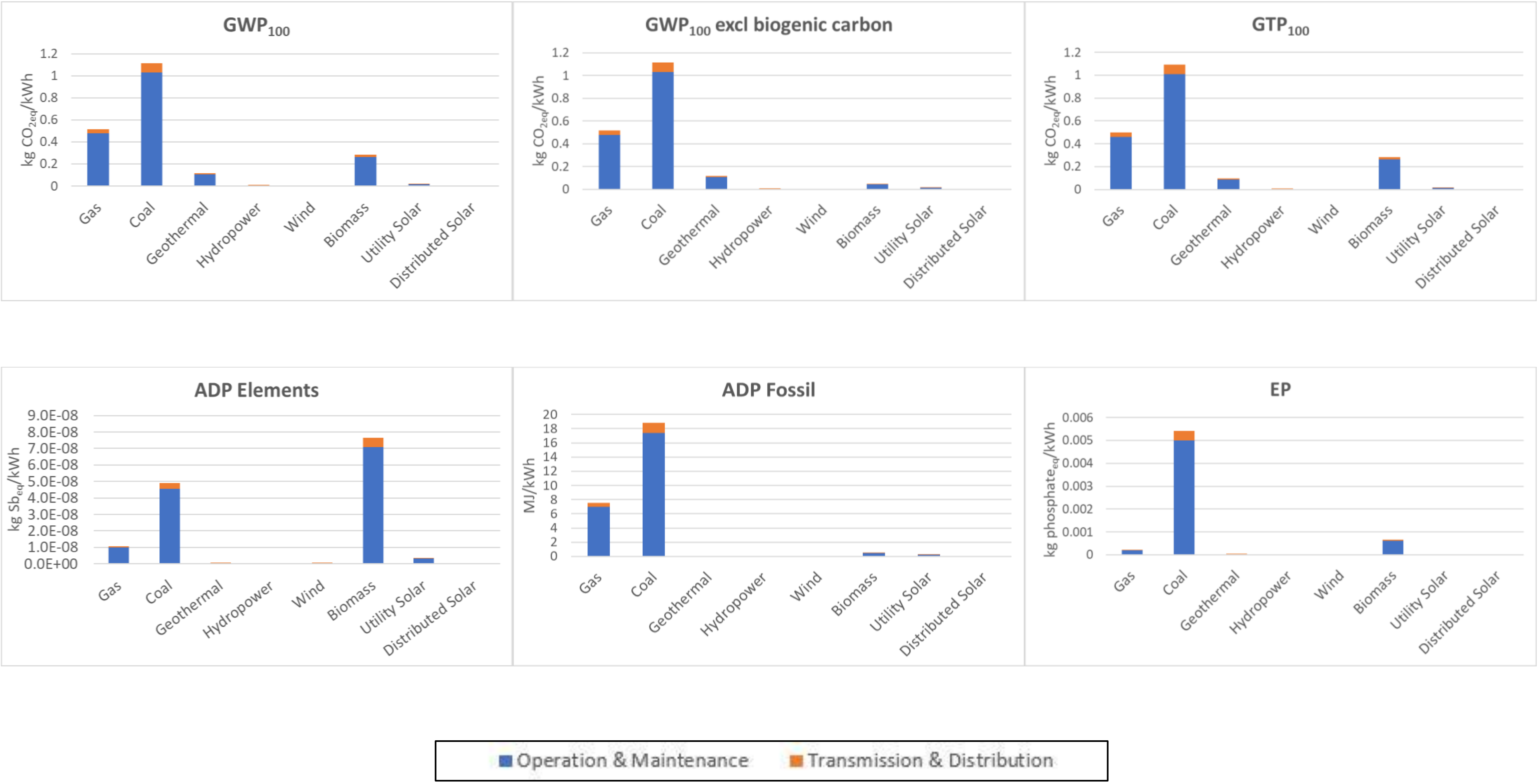

Figure 6.1: Operational Impacts per kWh by Generation Technology for GWP$_{100}$, GWP$_{100}$ excl, GTP$_{100}$, ADP elements, ADP fossil and EP Indicators

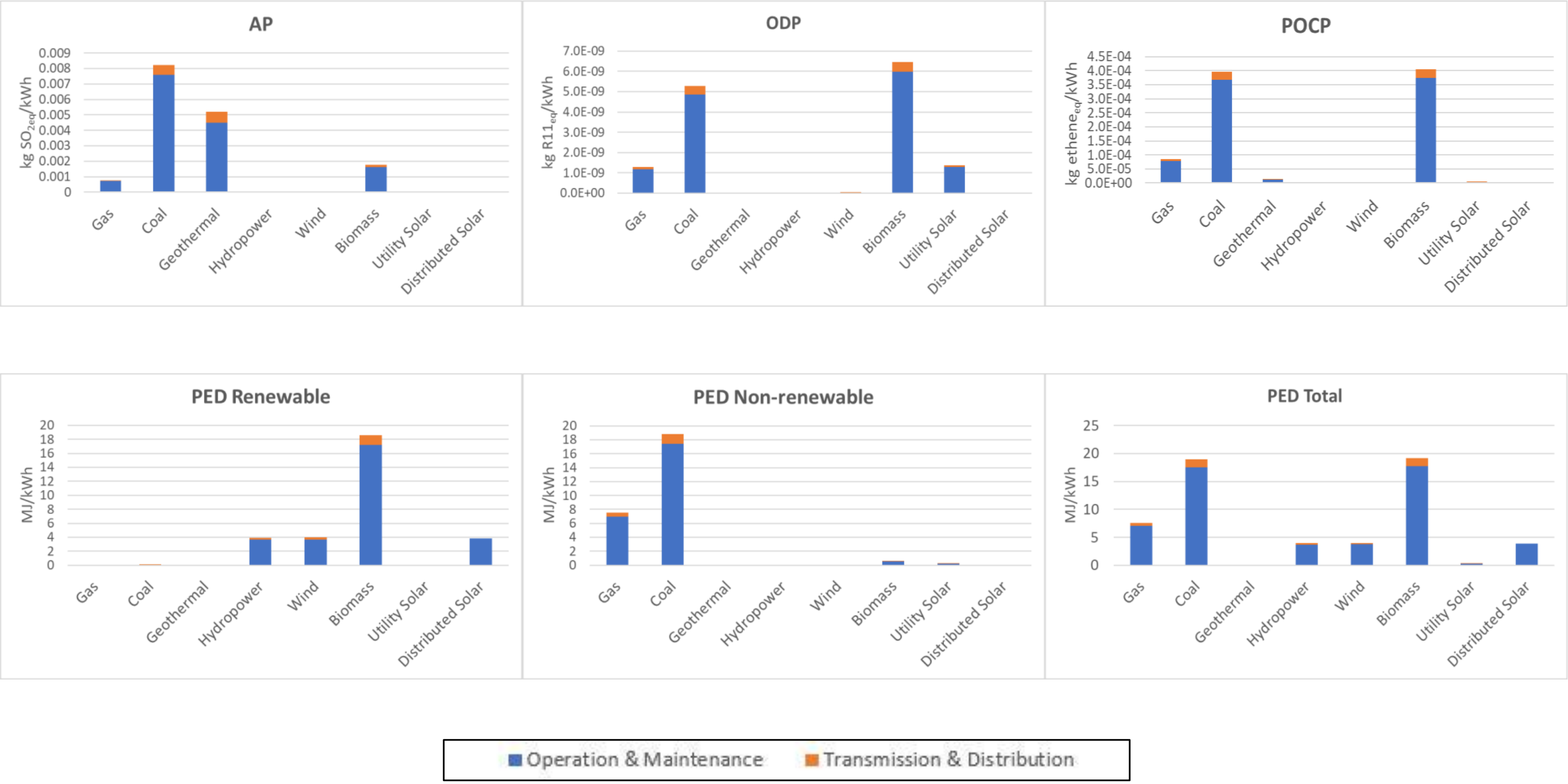

Figure 6.2: Operational Impacts per kWh by Generation Technology for AP, ODP, POCP, PED renewable, PED non-renewable and PED total Indicators

6.1.2 Infrastructure Impacts Per MW Generated

Figure 6.3 and Figure 6.4 show the infrastructure impacts associated with each MW of new build generation capacity i.e. the embodied impacts associated with construction of new electricity generation facilities (Appendix I). No new coal or biomass generation facilities are included in the future electricity generation scenarios and therefore infrastructure for these fuel types are not included in this assessment.

Utility solar or distributed solar infrastructure has the highest impact per MW for all indicators. Utility solar has the highest impacts for the climate change, ADP fossil, EP, AP, POCP and PED non-renewable indicators. Distributed solar has the highest impacts in ADP elements, ODP, PED renewable and PED total indicators.

The life cycle stage of distributed solar infrastructure that makes the biggest contribution to the impacts is the production of the solar panel. The life cycle stages of utility solar infrastructure that make the biggest contribution to the impacts are the collector field area, the production of the power block and the production of the thermal storage system.

Wind infrastructure represents the next highest level of infrastructure impacts after the solar generation technologies in all other indicators except ADP elements and ODP. Gas power stations have the lowest infrastructure impacts for all indicators.

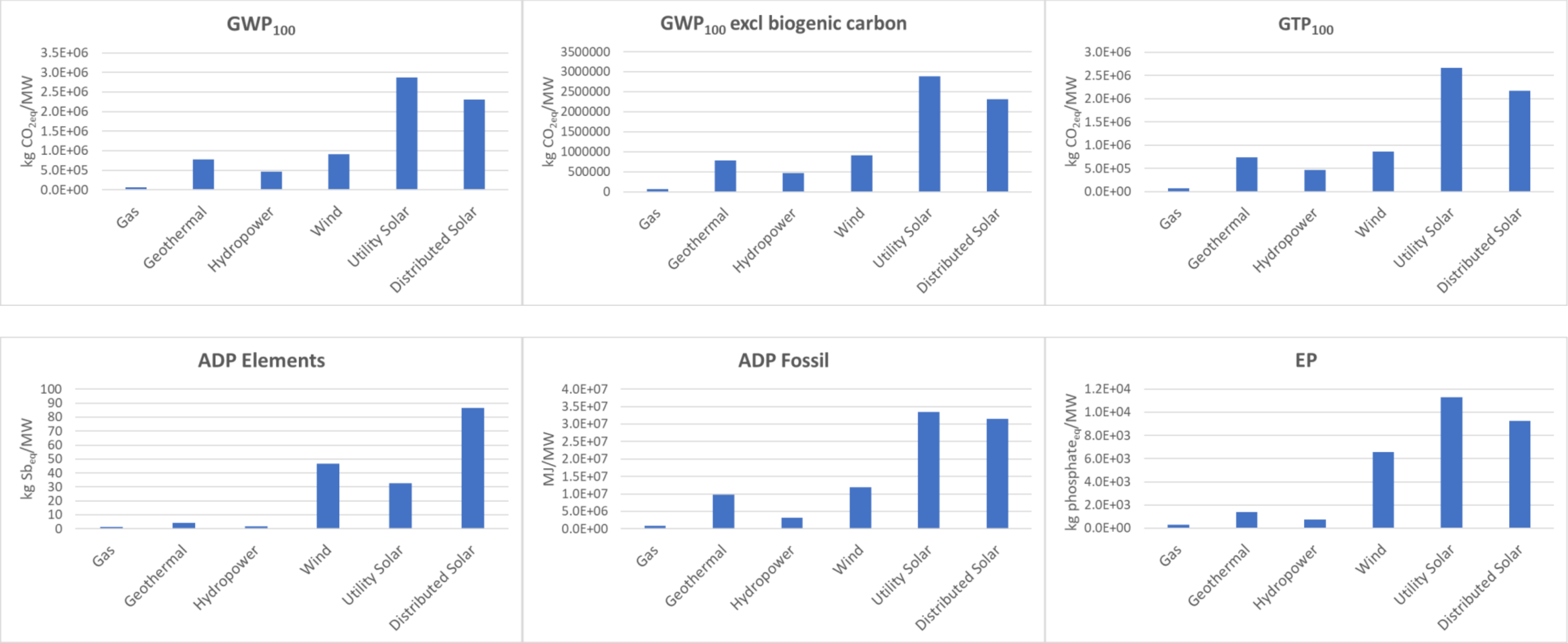

Figure 6.3: Infrastructure Impacts per MW of New Generation by Technology for GWP_{100}, GWP_{100} excl, GTP_{100}, ADP elements, ADP fossil and EP Indicators

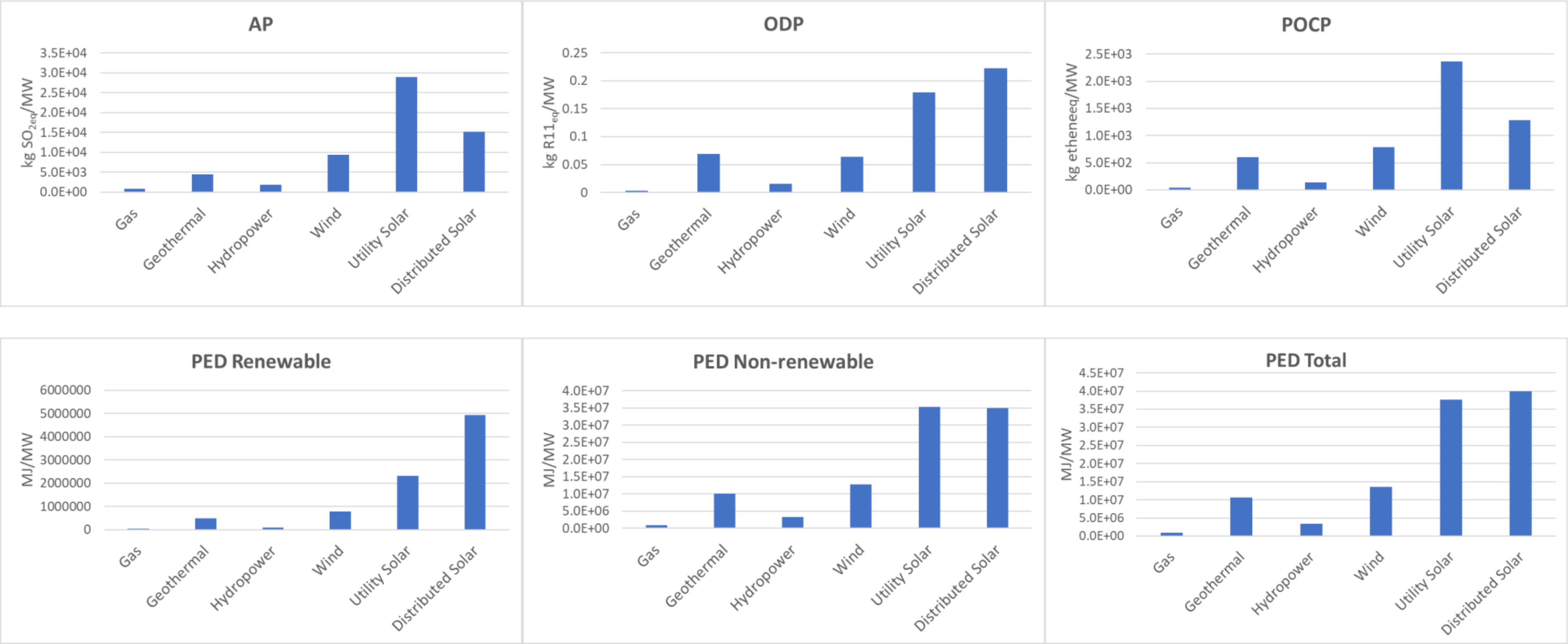

Figure 6.4: Infrastructure Impacts per MW of New Generation by Technology for AP, ODP, POCP, PED renewable, PED non-renewable and PED total Indicators

6.2 Cumulative Environmental Impacts of Generation Scenarios

The total life cycle-based environmental impacts per annum are comprised of the sum of the O&M, T&D, and Infrastructure impacts. Total environmental impacts per annum on a cumulative basis are shown in Figure 6.5 which shows the differences between the scenarios more clearly than plotting impacts on an annual basis. This figure shows the cumulative results from 2018 to 2050 for the MBIE scenarios and from 2019 to 2035 for the ICCC scenarios.

On a cumulative basis, in 2050, the order of the MBIE scenarios from the highest to the lowest level of impact is the same for all indicators: Disruptive (highest), Environmental, Growth, Reference, Global (lowest). The range of impacts between the different MBIE scenarios varies from 16 to 57% (measured as a percentage reduction relative to the Disruptive scenario).

The Accelerated Electrification scenario has the highest impact of the three ICCC scenarios on a cumulative basis in 2035 for all indicators. The Business as Usual scenario has the lowest impact for the ADP elements, AP, EP, ODP, POCP and PED renewable indicators, and the 100% Renewable scenario has the lowest impact for ADP fossil, GWP_{100}, GWP_{100} excluding biogenic, GTP_{100}, PED non-renewable and PED total.

The order of the scenarios in terms of cumulative impacts generally mirrors the order of the scenarios in terms of total generation (Table 5.2) with the Disruptive scenario having the highest total generation and the Global scenario the lowest generation in the MBIE scenarios. The ICCC Accelerated Electrification scenario has the highest level of generation within the ICCC scenarios followed by the 100% Renewable and the Business as Usual scenario with the lowest level of generation.

Appendix J contains a summary of the cumulative total impacts over the modelling period together with the total annual results in 2019, 2035 and 2050 for each indicator.

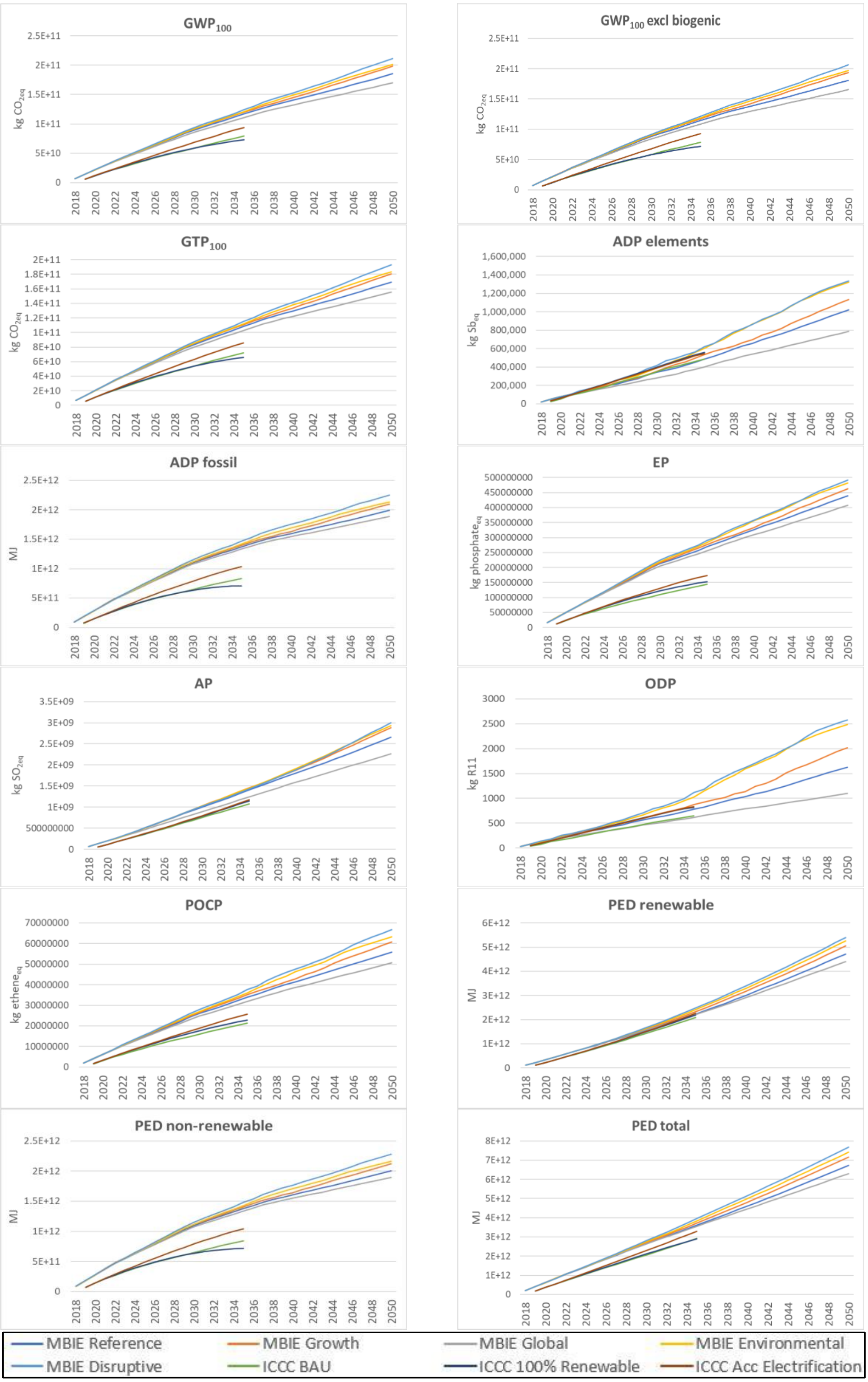

Figure 6.5: Total Cumulative Environmental Impacts per Annum for Five MBIE Scenarios (2018-2050) and Three ICCC Scenarios (2019-2035)

6.3 Life Cycle Stages Contributing to Impacts

6.3.1 Contribution of Operational versus Infrastructure Impacts

Table 6.1 provides a summary of the percentage contribution from operational impacts (i.e. O&M plus T&D) and infrastructure impacts (including T&D infrastructure) for each indicator and scenario based on cumulative impacts over the study period (i.e. 2018-2050 for MBIE scenarios and 2019-2035 for ICCC scenarios).

Operational impacts account for over 84% of the climate change, ADP fossil, AP, and PED indicator results. Operational impacts are also greater for EP and POCP with operational impacts accounting for 50-75% of EP impacts and 63-81% of POCP impacts depending on the scenario.

Infrastructure impacts account for over 99% of the impacts for ADP elements and 53-78% for ODP.

Table 6.1: Relative Contribution of Operational and Infrastructure Impacts by Scenario and Indicator based on Total Cumulative Impacts from 2018-2050 for MBIE Scenarios and 2019-2035 for ICCC Scenarios (red highlight indicates operational or infrastructure impacts account for >90% of total impacts)

	MBIE Scenarios								ICCC Scenarios							
	Reference (%)		Growth (%)		Global (%)		Environmental (%)		Disruptive (%)		BAU (%)		100% Renewable (%)		Accelerated Electrification (%)	
	Operational	Infrastructure	Operational	Infrastructure	Operational	Infrastructure	Operational	Infrastructure	Operational	Infrastructure	Operational	Infrastructure	Operational	Infrastructure	Operational	Infrastructure
GWP$_{100}$	92.4	7.6	90.3	9.7	95.3	4.7	88.0	12.0	88.2	11.8	92.5	7.5	88.3	11.7	91.3	8.7
GWP$_{100}$ excl biogenic	92.2	7.8	90.0	10.0	95.1	4.9	87.7	12.3	87.8	12.2	92.3	7.7	87.9	12.1	91.2	8.8
GTP$_{100}$	92.2	7.8	90.0	10.0	95.1	4.9	87.6	12.4	87.9	12.1	92.2	7.8	87.8	12.2	91.1	8.9
ADP elements	0.5	99.5	0.5	99.5	0.7	99.3	0.4	99.6	0.4	99.6	0.4	99.6	0.3	99.7	0.4	99.6
ADP Fossil	90.8	9.2	88.3	11.7	94.6	5.4	85.3	14.7	85.7	14.3	90.6	9.4	84.4	15.6	89.9	10.1
EP	70.1	29.9	67.0	33.0	75.0	25.0	64.0	36.0	64.1	35.9	56.6	43.4	50.1	49.9	42.4	57.6
AP	92.5	7.5	91.6	8.4	93.3	6.7	90.5	9.5	90.5	9.5	91.4	8.6	89.7	10.3	90.3	9.7
ODP	32.5	67.5	27.2	72.8	47.5	52.5	22.1	77.9	22.9	77.1	28.6	71.4	22.6	77.4	27.5	72.5
POCP	75.3	24.7	71.1	28.9	81.0	19.0	67.6	32.4	68.4	31.6	70.4	29.6	62.8	37.2	68.5	31.5

	MBIE Scenarios								ICCC Scenarios							
	Reference (%)		Growth (%)		Global (%)		Environmental (%)		Disruptive (%)		BAU (%)		100% Renewable (%)		Accelerated Electrification (%)	
	Operational	Infrastructure	Operational	Infrastructure	Operational	Infrastructure	Operational	Infrastructure	Operational	Infrastructure	Operational	Infrastructure	Operational	Infrastructure	Operational	Infrastructure
PED renewable	99.5	0.5	99.4	0.6	99.7	0.3	99.3	0.7	99.3	0.7	99.5	0.5	99.5	0.5	99.5	0.5
PED non-renewable	90.1	9.9	87.5	12.5	94.2	5.8	84.3	15.7	84.7	15.3	89.9	10.1	83.4	16.6	89.2	10.8
PED total	96.7	3.3	95.9	4.1	98.0	2.0	94.9	5.1	94.9	5.1	96.8	3.2	95.5	4.5	96.2	3.8

6.3.2 Changes in Infrastructure Impacts Over Time

The change in the proportion of impacts due to operational or infrastructure impacts over time was investigated by comparing the percentage contribution of infrastructure impacts to total impacts over three 10 year periods (2018 -2028; 2029-2039; and 2040-2050) for the Reference, Global and Disruptive scenarios. These scenarios were selected as they represent medium (Reference), low (Global) and high (Disruptive) levels of new infrastructure construction over the 2018 to 2050 modelling period. Figure 6.6 shows the results of this comparison for each indicator.

The proportion of impacts due to infrastructure impacts increases over each subsequent 10 year period for most indicators and scenarios. The increase is greatest for the Disruptive scenario, followed by the Reference scenario and least for the Global scenario reflecting the different amounts of new generation infrastructure under each scenario.

Infrastructure impacts contributing to ODP show the greatest increase over the time period.

The primary contributor to ODP is distributed solar infrastructure (Section 6.3.4); production of the solar panel accounts for 89% of the ODP impact in the distributed solar infrastructure life cycle. In an LCA study of multi-Si PV systems in China, Fu, Liu, and Yuan (2015) found that Halon (1301), carbon tetrachloride, and Halon (1211) contributed the majority of the ODP impacts during the module production and solar grade polycrystalline silicon production processes.

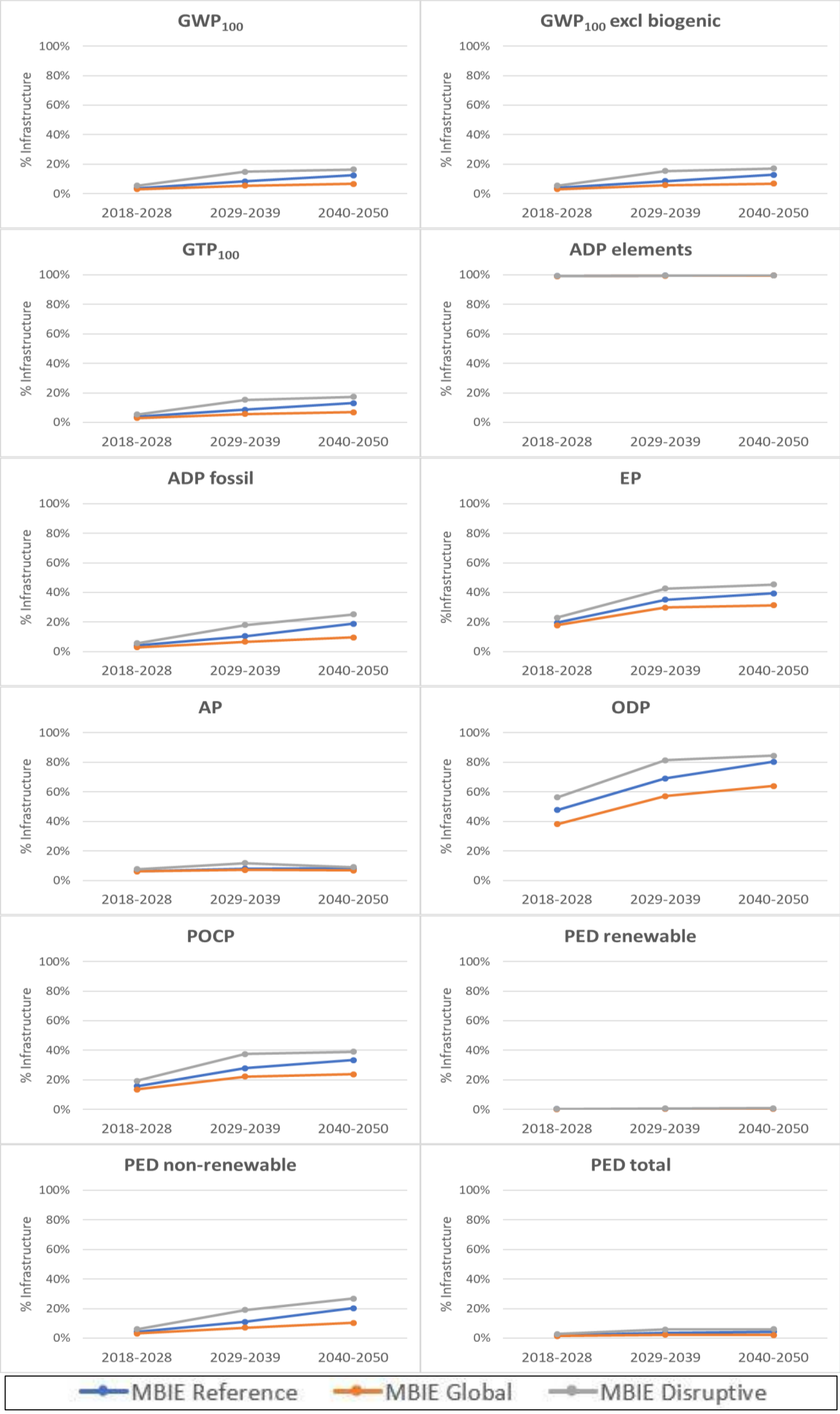

Figure 6.6: Comparison of % Contribution from Infrastructure from Reference, Global and Disruptive Scenarios during 2018-2028, 2029-2039 & 2040-2050

6.3.3 Life Cycle Stages Contributing to Climate Change Indicators

Figure 6.7 shows the contribution from each life cycle stage per year to GWP_{100} for each of the five MBIE scenarios (2018-2050) and three ICCC scenarios (2019-2035). The results for the other climate change indicators ($GWP_{100excl}$ and GTP_{100}) are similar (Appendix K). The primary contributors to impacts are O&M impacts from coal (14-30%), gas (29-48%) and geothermal (19-28%). The contribution from coal is higher for the MBIE scenarios (23-30%) compared to the ICCC scenarios (14-16%). T&D operational impacts contributes 6-7% of the total impacts for all scenarios, and infrastructure impacts are no greater than 6% for any one infrastructure type. Impacts due to distributed solar infrastructure become more significant from the mid-2030s onwards for those MBIE scenarios that assume a significant increase in this generation technology (i.e. Growth, Environmental and Disruptive scenarios). The primary contributor to these impacts within the distributed solar infrastructure life cycle is the production of solar panels.

The total impacts for the three climate change indicators generally decrease until around 2040 for all scenarios as the proportion of coal and gas in the generation mix decreases even though the total generation is increasing. However, for the MBIE scenarios, the total annual impact starts to increase or remain stable during the 2040s, reflecting the continued growth in total generation.

The use of GWP_{100} and GTP_{100} provides an indication of both shorter and longer-term climate change impacts. GWP_{100} can be interpreted as a proxy for temperature impacts within about four decades and GTP_{100} is recommended to assess long-term climate change impacts (as discussed in Section 4.3). The numerical results for GTP_{100} (Appendix K) are lower than GWP_{100} for all scenarios but the general trends for both indicators are the same.

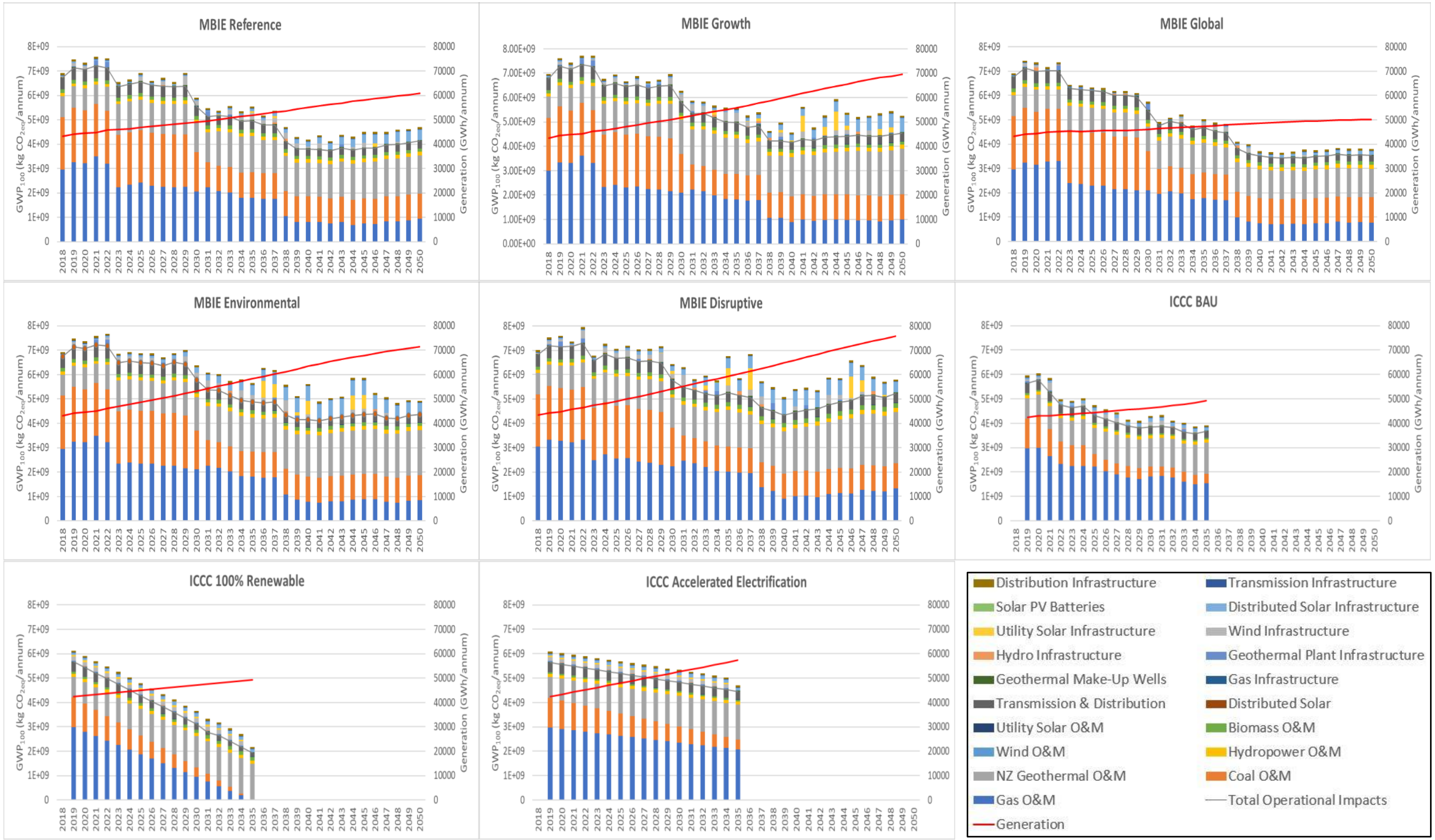

Figure 6.7: Annual Global Warming Potential 100 years (GWP$_{100}$) by Scenario and Life Cycle Stage.

6.3.4 Life Cycle Stage Contributing to Other Impact Categories

Appendix K provides a detailed discussion of the different life cycle stages contributing to the total impacts for each indicator (except the climate change indicators) and scenario.

The main contributors to the ADP elements indicator are infrastructure impacts, particularly distribution infrastructure (47-80%) reflecting the use of copper in distribution lines. The primary contributors to ADP fossil are O&M impacts of coal (22-44%) and gas (40-62%).

The most important contributor to the EP indicator is coal O&M which accounts for 34-59% of total impacts depending on the scenario. The total level of EP impacts is closely related to the amount of coal generation. However, in some scenarios, a decrease in impacts due to reducing coal generation over time is partially offset by increased impacts from renewable generation infrastructure.

The biggest contributor to the AP indicator is geothermal O&M which accounts for 66-73% of total impacts. The contribution from geothermal O&M is largely due to emissions of NH_3 to air which were based on the minimum emission values from a study of geothermal plants in Italy (Bravi & Basosi, 2014). Emissions from geothermal fields are very site specific (Bayer et al., 2013) and this value may not be representative of New Zealand conditions. The next most significant contributor is coal which accounts for 7-16% of total impacts. The total impacts for this indicator are relatively steady throughout the study period as impacts due to geothermal O&M increase as impacts due to coal O&M decrease.

The most important single contributor to ODP for most scenarios is infrastructure associated with new distributed solar generation (17-43%).

The largest contributor to POCP for the MBIE scenarios is coal O&M (26-34%) whereas the largest contributor for the ICCC scenarios is gas O&M (19-28%). This reflects the lower proportion of coal generation and higher proportion of gas generation under the ICCC scenarios.

The biggest contributor to PED renewable is hydropower O&M (61-75%) reflecting the predominance of hydropower in the New Zealand generation mix. Overall, the level of PED renewable increases over time for all scenarios as the proportion of renewable generation increases.

The biggest contributors to PED non-renewable are gas O&M (40-61%) and coal O&M (22-43%). Overall, the level of PED non-renewable decreases over time for all scenarios as the proportion of fossil fuel generation decreases.

Impacts vary from year to year for most scenarios largely dependent on the amount and type of new generation infrastructure. Under the Growth, Environmental and Disruptive scenarios, the ADP elements, AP, ODP and POCP indicators tend to increase during the 2030s and 2040s and become more variable between years due to significant increases in solar and wind generation construction during this time.

6.3.5 Normalisation of Impacts Categories

To understand the relative importance of different indicators, particularly those that are strongly related to the construction of renewable generation infrastructure, a normalisation of the total cumulative results for the MBIE Disruptive Scenario was undertaken. This scenario was selected as it represents the scenario with the greatest amount of new renewable generation including distributed solar during the modelling period (2018-2050).

Figure 6.8 shows the normalised impacts for the Disruptive Scenario for CML indicators based on a CML normalisation against global impacts for the year 2000. The AP indicator has the highest value followed by ADP fossil and GWP_{100}. The ODP impacts are very small on a normalised basis. Normalised ADP elements impacts are very small when operational impacts only are considered but becomes the fourth most significant impact category when infrastructure impacts are also included. The CML normalisation method does not include the other indicators included in this study.

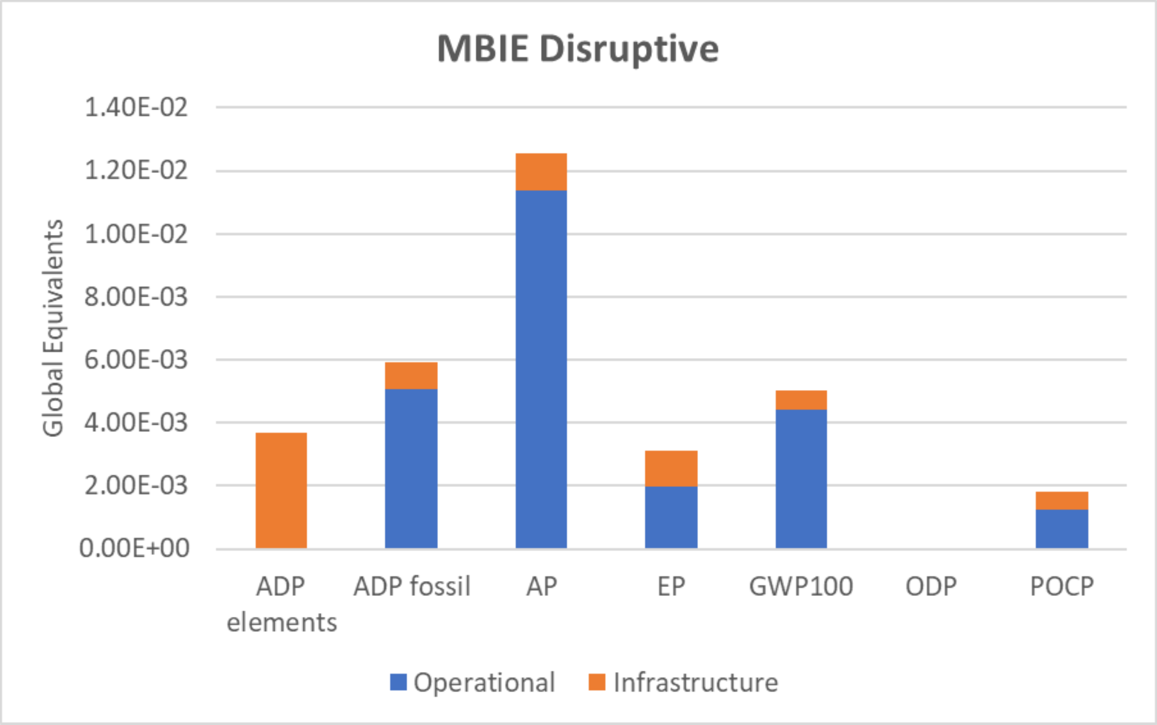

Figure 6.8: Normalised Total Cumulative Impacts for MBIE Disruptive Scenario (2028-2050) for CML Indicators (Normalisation Based on CML World, Year 2000)

6.4 Sensitivity Analysis

A number of assumptions were made in order to model the impacts of future electricity generation and supply. These assumptions are an integral aspect of modelling a complex system. In this study, sensitivity analyses were undertaken of geothermal fugitive emissions and the allocation of emissions from fossil fuel cogeneration facilities due to the significant contribution of these life cycle stages to many of the results.

6.4.1 Geothermal Fugitive Emissions

McLean and Richardson (2019) investigated geothermal fugitive emissions from New Zealand geothermal fields (Section 3.2) and determined a generation weighted mean carbon footprint of 0.087 kg CO_{2eq}/kWh for New Zealand geothermal fields based on field measurements of CO_2 and CH_4 emissions from individual fields. This is 22% lower than the equivalent base case figure used in this study of 0.112kg CO_{2eq}/kWh based on reported emissions for the 2017 year (MBIE, 2019d).

To investigate the significance of a potentially lower level of geothermal fugitive emissions, the MBIE Global and Disruptive scenario models were re-run using a carbon footprint of 0.087kg CO_{2eq}/kWh to represent fugitive emissions of CO_2 and CH_4. A CH_4 characterisation factor of 25 was used by McLean and Richardson (2019) rather than 28 as used in this study; however, this was not considered to be significant as CH_4 emissions generally comprise a relatively small proportion of the total geothermal carbon footprint. For example, CH_4 emissions comprise 3-18% of the carbon footprint of Contact Energy geothermal plants (McLean, 2020). The MBIE Global and Disruptive scenarios were selected for this comparison as they represent both a low case (Global) and a high case (Disruptive) in terms of total geothermal generation. Geothermal contributes 333,573 GWh of generation under the Global scenario and 453,645 GWh of generation under the Disruptive scenario over the 2018-2050 modelling period.

The alternative carbon footprint for geothermal emissions of 0.087kg CO_{2eq}/kWh resulted in an overall decrease in total impacts of 7.3% for the Global scenario and a decrease of 7.9% for the Disruptive scenario for cumulative GWP_{100} results over the 2018-2050 modelling period.

The contribution of geothermal O&M impacts to the total cumulative life cycle carbon footprint (2018-2050) decreased from 21 to 15% for the Global scenario, and from 23% to 17% for the Disruptive scenario. In other words, there was a reduction of 6% for both scenarios when using the alternative geothermal fugitive emission data.

6.4.2 Allocation of Cogeneration Emissions

Electricity generation from coal and gas originates from both electricity only power plants and cogeneration plants which produce both heat and electricity as useful co-products. In 2017, 54% of coal electricity generation and 15% of gas electricity generation occurred in cogeneration facilities.

The allocation of inputs and emissions where two products are produced from a single process is an important methodological consideration in LCA. Several studies have considered the allocation of emissions from cogeneration facilities and have demonstrated that the choice of allocation method can have a significant impact on the proportion of emissions allocated to electricity and the resulting impacts. Due to the absence of publicly available data regarding heat production from cogeneration facilities in New Zealand, it was not possible to adopt commonly used allocation methods in this assessment. Consequently, in this study it was assumed that the combustion emissions allocated to electricity from cogeneration facilities were the same as those from electricity only coal or gas generation plants in New Zealand (Sections 5.6.2.3 and 5.6.3.3). To test the influence of this method on the results, a sensitivity assessment was undertaken using a range of alternative allocation values for emissions from gas and coal cogeneration plants.

The sensitivity assessment used the combustion emissions from electricity only gas and coal plants as the base-case and explored the impact of allocating different proportions of the total emissions from cogeneration facilities to electricity. Based on the range of allocation values determined from case studies undertaken by Tereshchenko and Nord (2015) and Gao et al. (2018) (Section 5.6.2.3), allocations of 40%, 60%, 80% or 95% of emissions to electricity were compared for the MBIE Global scenario. The Global scenario was used for this assessment as this is the scenario with the greatest proportion of gas and coal generation relative to total generation. Table 6.2 provides a summary of the percentage change in the total life cycle impacts (sum of O&M, T&D and Infrastructure impacts) due to the different allocations of cogeneration emissions compared to the base-case over the modelling period (2018-2050).

The greatest reduction in impacts compared to the base case is seen in the ADP fossil, EP and PED non-renewable indicators where a 40% allocation of emissions to electricity reduces the overall life cycle impacts by 12.6%, 17% and 12.6% respectively. In contrast, a 95% allocation of emissions to electricity would increase the impacts for GWP_{100}, GWP_{100} excl biogenic, GTP_{100} and ADP fossil by between 4.9% and 6.8% compared to the base case. As expected, categories where the greatest changes occur are those indicators where impacts due to coal or gas O&M impacts are the largest contributors to total impacts (Sections 6.3.3 and 6.3.4).

It can be concluded that adopting an alternative allocation method to that used as a base case in this study could decrease the total life cycle impacts by up to 17% or increase the impacts by up to 7% depending on the impact category and allocation method selected.

Table 6.2: Summary of Percentage Change in Total Emissions for Differing Allocation of Cogeneration Emissions to Electricity Compared to Base Case Allocation (Global Scenario) over 2018-2050 Modelling Period (red highlight indicates change of >5% compared to base case)

Indicator	% of Cogeneration Emissions Allocated to Electricity			
	40%	60%	80%	95%
GWP_{100}	-8.4	-3.4	1.1	4.9
GWP_{100} excl biogenic	-8.6	-4.0	1.2	5.1
GTP_{100}	-9.2	-3.6	1.2	5.4
ADP elements	-0.1	0.0	0.0	0.0
ADP Fossil	-12.6	-5.7	1.6	6.8
EP	-17.0	-10.9	-5.1	-0.6
AP	-3.7	-1.8	-0.4	1.1
ODP	-4.1	-2.0	0.2	1.9
POCP	-8.6	-4.3	0.1	3.3
PED renewable	0	0	0	0
PED non-renewable	-12.6	-5.3	1.5	6.7
PED total	-3.8	-1.7	0.5	2.0

6.5 Carbon Footprint Comparison with Climate Change Planetary Boundaries

6.5.1 Electricity Planetary Boundary

The carbon footprint of MBIE electricity scenarios compared to the climate change planetary boundaries (PBs), using three different combinations of sharing principles (Section 5.10), are shown in Figure 6.9. The carbon footprint is represented by the cumulative GWP_{100} results between 2018 and 2050 for each of the five scenarios and the PB by a horizontal line representing the total carbon budget (CB) between 2018 and 2050.

All five MBIE scenarios exceed the allocated CB for all three PBs many years prior to 2050. The ‘Economic + Economic’ and ‘Equal per capita + Grandfather’ PBs are exceeded by all MBIE scenarios between 2022 and 2024. The ‘Economic + Grandfather’ PB is exceeded by all MBIE scenarios between 2037 and 2041.

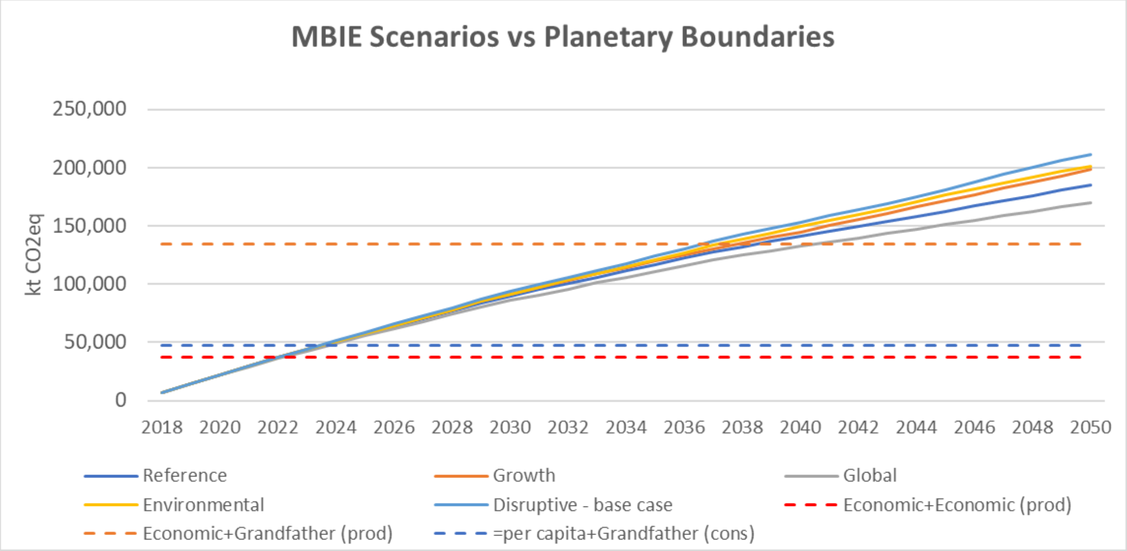

Figure 6.9: Comparison of Carbon Footprint of MBIE Scenarios with Planetary Boundaries

The carbon footprint of the ICCC scenarios compared to PBs using the three different combinations of sharing principles are shown in Figure 6.10. As the ICCC scenarios only cover the period from 2019 to 2035, the PBs for the ICCC scenarios have been scaled to represent the relevant proportion of the budget calculated for 2018-2050 (i.e. 51.5%).

All three ICCC scenarios exceed the allocated CB for all three PBs prior to 2035. All ICCC scenarios exceed the ‘Economic + Economic’ and ‘Equal per capita + Grandfather’ PBs during 2022 or 2023. The ‘Economic + Grandfather’ PB is exceeded by all ICCC scenarios between 2031 and 2034.

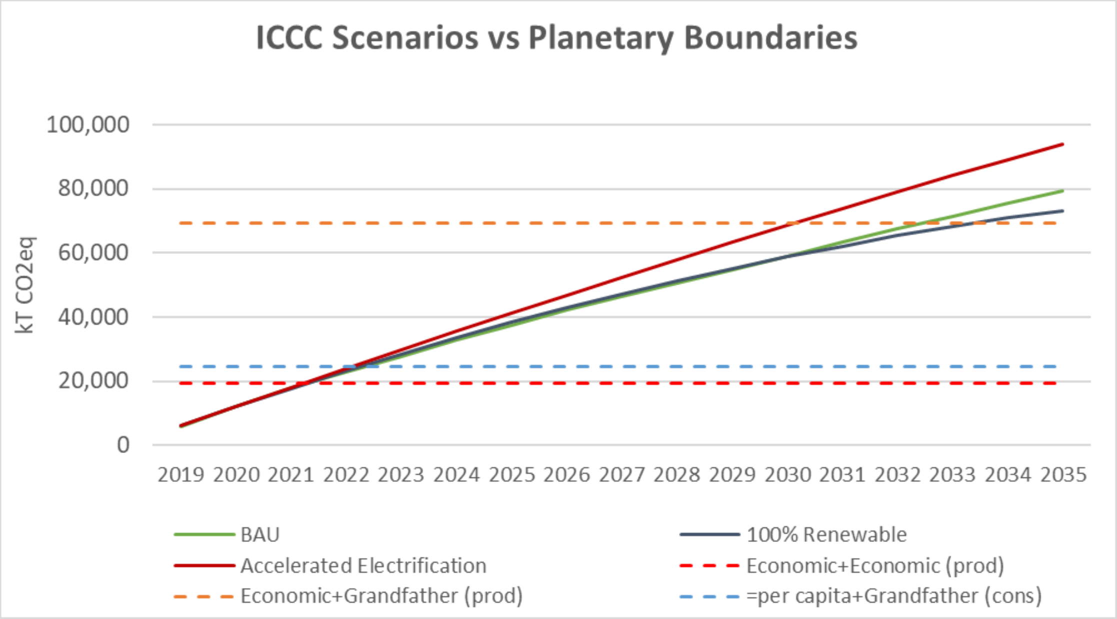

Figure 6.10: Comparison of Carbon Footprint of ICCC Scenarios with Planetary Boundaries

6.5.2 Sharing the Benefits of Electrification

One of the factors that contributes to the exceedance of the carbon footprint PBs for electricity (Section 6.5.1) is the generation demand growth that occurs throughout the modelling period. This growth is partly due to the predicted electrification of process heat and land transport that is currently directly fuelled by fossil fuels (ICCC, 2019a). This raises an important issue of how the benefits of electrification should be shared across the different energy sectors as a decrease in the carbon footprint of the process heat and transport sectors results in an increase in the carbon footprint of the electricity sector.

Sharing the benefits of electrification of process heat and transport was explored in the context of PBs for the MBIE Disruptive scenario which is the MBIE scenario with the greatest increase in generation due to electrification of process heat and transport.

The potential benefits from electrification of process heat and land transport from 2018 to 2050 were estimated based on predictions of the future carbon footprint of the manufacturing and land transport sectors under the Disruptive scenario using data provided by MBIE (2019g). This data provided the future carbon footprint of different sub-sectors of the overall energy sector using the same scenarios investigated in this study. Land transport was provided as an individual sub-sector and the manufacturing sector (excluding chemical processing such as methanol production) was used to represent process heat.

Under the Disruptive scenario, the carbon footprints of manufacturing and land transport are predicted to decrease every year between 2020 and 2050. The benefits of electrification in these sectors were assumed to be the difference between the carbon footprint in 2020 and the carbon footprint for each year from 2021 to 2050. In other words, it is assumed that the carbon footprint of manufacturing and land transport would remain stable at 2020 levels in the absence of electrification in these sectors.

Figure 6.11 shows the net carbon footprint for the electricity sector using three different approaches to attributing the benefits of electrification to the electricity sector. The three different carbon footprints represent the net carbon footprint for the electricity sector with 100%, 50% or none of the benefits of electrification subtracted from the original cumulative carbon footprint of the electricity sector. The carbon footprint with no benefits attributed to the electricity sector represents the base case used in the PB assessment in Section 6.5. The three PBs used previously are also shown in Figure 6.11.

Applying either 100% or 50% of the benefits from electrification to the electricity sector significantly alters the carbon footprint of the Disruptive scenario with respect to the PBs compared to the base case carbon footprint with no benefits allocated to electricity. The carbon footprint of New Zealand electricity does not exceed the ‘Economic+Grandfather’ PB if either 100% or 50% of the benefits are applied to electricity. The ‘Per Capita+Grandfather’ and ‘Economic+Economic’ PBs are still exceeded if 50% of the benefits are applied to electricity. However, if 100% of the benefits are allocated to the electricity sector, these PBs are exceeded for a period of time (2023-2047) then, the cumulative carbon footprint falls to a level below both the ‘Per Capita+Grandfather’ and ‘Economic+Economic’ PBs from 2048 onwards.

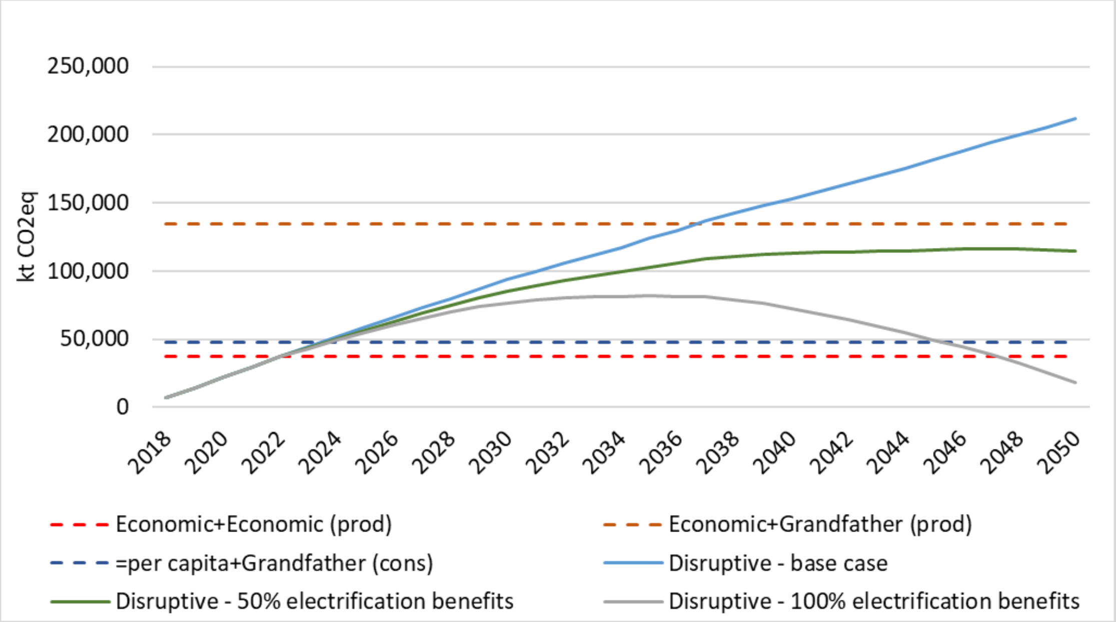

Figure 6.11: Comparison of Carbon Footprint of Disruptive Scenario against Planetary Boundaries with 50% and 100% of Electrification Benefits Attributed to Electricity Sector Compared to Base Case with 0% of Benefits Attributed to Electricity Sector

These results show the difficulties of applying a PBs approach to different sectors where those sectors are interrelated and changes in one sector can impact on the environmental performance of other sectors. Ideally, a PBs approach would be applied to the New Zealand energy sector as a whole. However, the data were not readily available to undertake a PB assessment of the whole energy sector.

A limitation of the approach presented above is that a number of other potentially influencing factors such as changes in demand, manufacturing emissions other than process heat, and the impact of changes in technology are not taken into consideration. However, as a comparison, the avoided emissions in the manufacturing and land transport sectors in 2035 under the Disruptive scenario calculated using this method (6,075 kt CO_{2eq}) are significantly less than the avoided emissions calculated by the ICCC (2019a) in the same year (9,000 kt CO_{2eq}) for the Accelerated Electrification scenario. These two electricity scenarios have a similar generation size and proportion of renewable generation in 2035. Therefore, the approach taken in this assessment is considered to represent a conservative estimate of the benefits of electrification.

Data was not available for the carbon footprint associated with the other life cycle stages of manufacturing and land transport; therefore, another limitation of this comparison is that the benefits and impacts across the full life cycle of these sectors are not considered.

It can be concluded that the benefits associated with electrification of transport and process heat represents a significant factor that needs to be considered when comparing the carbon footprint of the electricity sector to climate change PBs.

7 Discussion

7.1 Environmental Impacts and Benefits of Different Generation Scenarios

When compared with each other, the total cumulative environmental impacts of each scenario over the studied time period are closely related to the amount of total generation.

For those scenarios where renewable generation makes up a greater proportion of the overall generation mix, the impacts for the climate change indicators, ADP fossil and PED non-renewable categories tend to be lower than for other scenarios. This is because fossil fuels are the largest contributors to these impacts.

The impacts for other environmental indicators (ADP elements, ODP, EP, AP and POCP) are strongly influenced by infrastructure impacts associated with the construction of new renewable generation infrastructure. Solar generation, in particular, results in relatively high infrastructure impacts although it makes up a relatively small proportion of the generation mix.

In summary, the most significant factors affecting the impacts of electricity generation and supply for the different scenarios are the overall size of generation, the relative proportions of renewable and fossil fuel generation (particularly coal generation), and the infrastructure impacts associated with new renewable generation infrastructure (particularly solar generation infrastructure).

7.2 Infrastructure versus Operational Impacts

The different environmental indicators considered in this study can be separated into three different categories in terms of the importance of operational versus infrastructure impacts:

- Category 1: indicators where impacts are predominantly operational (GWP_{100}, GWP_{100} excl biogenic, GTP_{100}, ADP fossil, AP, PED renewable, PED non-renewable and PED total). Operational impacts account for at least 83% of total impacts over the modelling period for the climate change, ADP fossil, AP and PED indicators.
- Category 2: indicators where impacts are predominantly associated with infrastructure impacts (ADP elements, ODP). Infrastructure impacts account for 99% of ADP elements and over 52% of ODP impacts over the modelling period.
- Category 3: indicators where the greater proportion of impacts are operational, but infrastructure impacts are also an important contributor (EP and POCP). Operational impacts account for 42-84%, and infrastructure impacts account for 14-58%, of total impacts for the EP and POCP indicators.

The proportion of infrastructure impacts is not constant over time. There are significant increases in renewable generation during the 2030s and 2040s for most MBIE scenarios resulting in total infrastructure impacts becoming a more significant contributor for many indicators. For example, infrastructure impacts for ODP account for 38-56% of the total impacts for MBIE scenarios over the first 10 years of the modelling period but this increases to 64-86% during the final 10 years of the modelling period. Similarly, infrastructure impacts account for 3-5% of the total GWP_{100} impacts during the first 10 years but this increases to 7-18% during the final 10 years (Section 6.3.2).

The relative importance of operational and infrastructure impacts for different generation technologies, and changes in the generation mix over time, result in different patterns of the relative contributions of operational and infrastructure emissions over the modelling period for different indicators. For Category 1 indicators, the total impacts generally decrease during the 2020s and 2030s as the proportion of renewable generation increases and then plateau or gradually increase from the late 2030s onwards due to the influence of increasing total generation and increased renewable generation infrastructure. PED renewable increases over time for all scenarios, reflecting the increasing role of renewable generation.

The Category 2 and 3 indicators show a variety of patterns depending on the scenario. Indicators that are strongly influenced by infrastructure impacts such as ADP elements, ODP, EP and POCP exhibit significant inter-annual variability with peaks during years when new renewable generation infrastructure is constructed. The main contributors to high infrastructure impacts are solar (utility and distributed) and wind (Section 6.1.2).

7.3 Potential for Burden Shifting

An increase in the proportion of renewable generation has benefits in terms of the operational impacts of electricity generation and supply. However, there is potential for burden shifting to impact categories such as ADP elements and ODP as renewable generation replaces fossil fuels.

Distributed solar generation is the main contributor to this effect with distributed solar comprising only 1-3% of the generation mix for the MBIE scenarios over the 2018-2050 modelling period but accounting for 17-43% of ODP impacts and 9-31% of ADP elements impacts over the same period. This large impact from distributed solar infrastructure, compared to the small contribution to total generation, may partially reflect the relatively low efficiency of distributed solar generation. Average efficiencies of crystalline-silicon photovoltaic modules of less than 18% were reported in 2018 (Fraunhofer Institute for Solar Energy Systems, 2019).

The main contributors to ODP from distributed solar are the use of ozone depleting substances such as Halon during the production of the solar panel (Section 6.3.2). The main life cycle stages contributing to ADP elements are production of the solar panel (52%) and production of the inverter (36%). In a review of LCA studies of solar PV panels, Muteri et al. (2020) noted that the recycling of toxic metals and scarce elements was an important measure to reduce the environmental impacts of PV panels especially for the ADP indicator.

The high impacts associated with solar generation infrastructure may also reflect the high impacts associated with electricity or other inputs in the country of manufacture. Fu et al. (2015) found that the aluminium frame was a significant contributor to ODP, EP and GWP impacts during multi-Si panel production in China.

When these impact categories are considered on a normalised basis for the MBIE Disruptive Scenario (Section 6.3.5), the cumulative ODP impacts are minimal in the context of global ODP impacts compared to the other indicators. ADP elements impacts are more significant when considered on a normalised basis but are within the range of impacts observed for other indicators.

In summary, there is potential for burden shifting due to increased renewable generation particularly in the areas of ADP elements and ODP. This effect is due to both a switch from fossil fuel generation to renewable generation and an overall increase in demand for electricity resulting in an increased demand for additional renewable generation infrastructure. The impact of distributed solar generation is significant in this regard and accounts for a disproportionate amount of the impacts for these indicators compared to the proportion of generation from this technology.

7.4 Carbon Footprint of New Zealand Electricity

The carbon footprint of New Zealand electricity, represented by GWP_{100}, is strongly influenced by fossil fuel operational impacts. The carbon footprint of coal generation represents a significant proportion of the total carbon footprint despite being a relatively small part of the generation mix. Operational impacts of coal generation (1.11 kg CO_{2eq}/kWh) are more than twice as high as those of gas generation (0.517 kg CO_{2eq}/kWh) which has the next highest carbon footprint of any of the generation technologies. As an example, coal contributes only 1.7% of the generation mix of the MBIE Reference scenario in 2050 but accounts for 22% of the carbon footprint.

Although fossil fuel generation constitutes a relatively small and reducing component of the electricity generation mix, it represents a significant proportion of the carbon footprint over the modelling period for all scenarios. Fossil fuels represent 53-62% of the cumulative carbon footprint of the MBIE scenarios but only 9-11% of the generation mix over the modelling period (2018-2050). Fossil fuels make up a smaller proportion of generation under the ICCC scenarios (8-12%) but the operational impacts of fossil fuels still constitute 49-60% of the cumulative carbon footprint over the modelling period (2019-2035).

The Huntly Power Station is the one coal-fired electricity only power plant remaining in New Zealand and all of the scenarios assume that coal fired generation at Huntly is decommissioned around 2030. However, currently over half of coal generation (54% in 2017) is associated with coal-fired cogeneration plants and, after 2030, generation from coal fired cogeneration plants continues to make up approximately 2% of the generation mix for the MBIE scenarios. In fact, under the MBIE scenarios, the amount of coal cogeneration between 2030 and 2050 (approximately 1,000 GWh/year for all years and scenarios) is significantly higher than current coal cogeneration levels of around 600 GWh/year. In contrast, the ICCC scenarios assume a reduction in coal cogeneration compared to current levels.

The large proportion of fossil fuel generation from cogeneration facilities introduces a need to allocate the emissions from cogeneration facilities between the heat and electricity co-products. A sensitivity assessment based on the MBIE Global scenario concluded that adopting an alternative allocation method could result in a carbon footprint between 8.4% lower and 4.9% higher than the base case depending on the allocation method selected. Coal generation remains a significant contributor to the carbon footprint of electricity regardless of the allocation approach adopted.

Other than fossil fuels, the main contributors to the carbon footprint of New Zealand electricity are geothermal fugitive emissions and impacts associated with renewable generation infrastructure. Although fossil fuels comprise the most significant contributor to the carbon footprint, completely removing fossil fuels from the grid mix does not lead to a zero-carbon footprint.

A focus on minimising the emissions associated with geothermal generation will be an important area for study and technological improvement if further reductions in the carbon footprint of New Zealand electricity are to be achieved.

McLean and Richardson (2019) observed that the carbon footprint of fugitive emissions from New Zealand geothermal fields vary widely across the different geothermal fields. The generation weighted carbon footprint for geothermal fugitive emissions calculated by McLean and Richardson (2019) was 22% lower than the carbon footprint used as a base case in this study. A sensitivity analysis indicated that use of this alternative carbon footprint could potentially result in a decrease in the total carbon footprint of 7-8%. Geothermal operational impacts remain a significant proportion of the total carbon footprint even when using this lower carbon footprint for fugitive emissions.

In conclusion, coal and gas operational emissions are currently the most significant contributors to the carbon footprint of New Zealand electricity and continue to be significant contributors in the future despite comprising a reducing proportion of the electricity grid mix for all scenarios except the ICCC 100% renewable scenario. However, the relative importance of the carbon footprint associated with geothermal fugitive emissions and renewable generation infrastructure increases in the future as the contribution from fossil fuels decreases.

7.5 Carbon Footprint in the Context of Planetary Boundaries

A planetary boundary (PB) represents a safe operating space within which human activities do not exceed the natural limits of biophysical sub-systems or processes (Section 4.5). The carbon footprints of the different future electricity scenarios were compared to PBs for climate change based on three different sharing principles (Sections 5.10 and 6.5). All eight electricity scenarios exceeded the PBs based on all three sharing principles. The ‘Economic+Economic’ and ‘Per Capita+Grandfather’ PBs are exceeded by over 200% at the end of the modelling period by all scenarios. The ‘Economic+Grandfather’ PB is exceeded by the ICCC scenarios by at least 6% and by the MBIE scenarios by at least 27%.

However, the electricity sector does not operate in isolation and one of the main contributors to the growth in electricity demand, and therefore the carbon footprint of electricity, is the anticipated electrification of process heat and transport. This is one of the main factors that differentiates the different electricity scenarios considered in this study.

It could be argued that the benefits of electrification of process heat and transport should be accounted for within the carbon footprint of those sectors. However, the process of electrification essentially transfers the environmental burden from the manufacturing and transport sectors to the electricity sector and therefore it could also be argued that the electricity sector should accrue at least some of the benefits.

This issue was explored by allocating 100% or 50% of the benefits of electrification of the manufacturing and transport sectors to the electricity sector compare to the base case where none of the benefits were attributed to the electricity sector (Section 6.5.2). The ‘Economic+Grandfather’ PB was not exceeded when either 100% or 50% of the electrification benefits were applied to electricity. If 100% of the benefits were applied to electricity, the ‘Per Capita+Grandfather’ and ‘Economic+Economic’ PBs were exceeded for a period of time but the cumulative carbon footprint for electricity then fell below these boundaries during the late 2040s.

Although this analysis can only be regarded as a very rough indication of future impacts due to modelling constraints, it does illustrate that both the sharing and timing of electrification benefits is an important issue which can significantly affect whether the New Zealand electricity sector can be considered to be operating within a climate change PB.

8 Approaches to Modelling Electricity Use in LCA

8.1 Introduction

One of the research questions this study seeks to address concerns how future grid electricity should be modelled in New Zealand LCA studies of long-lived products such as buildings. This chapter further explores this question and applies the findings to a case study of a New Zealand detached house.

8.2 LCA Approaches and Modelling of Electricity Use

A number of modelling approaches in LCA have been identified and there is ongoing debate on the most appropriate approach for different modelling situations. Section 4.4 outlines some of the considerations and arguments for adopting different approaches but essentially three different modelling approaches have been identified:

- Attributional;
- Consequential; and
- Prospective attributional.

The most appropriate modelling approach is determined primarily by the nature of the question the LCA study is seeking to address. An attributional approach is most appropriate when the LCA study is seeking to describe the nature of the impacts associated with a product or service or when undertaking a relative LCA comparing two different products or services. A prospective attributional approach applies the attributional approach to a future situation and is often used to compare a number of possible future scenarios. In comparison, consequential LCA is most appropriate when seeking to understand the consequences of a change within a product system and how this will affect, not just the impacts of the product itself, but also the resultant impacts within related product systems. One of the key differences between attributional and consequential modelling (usually) is the use of average impacts (inputs and emissions) in attributional modelling compared to the use of the impacts of the marginal technology in consequential modelling.

The approach taken in this study is essentially a consequential modelling approach in terms of electricity infrastructure. In terms of construction impacts, only the changes to electricity infrastructure, or the marginal infrastructure, have been modelled and all impacts associated with producing and constructing the new built infrastructure have been allocated to the year of construction

The primary purpose in taking this approach to electricity infrastructure was to enable an absolute sustainability assessment of the electricity sector relative to the climate change planetary boundary. A planetary boundary comparison is concerned with the change in emissions over a set period of time directly related to a global target or boundary covering the same time period. This is also known as a ‘distance to target’ assessment. The approach taken in this study essentially ignores any infrastructure impacts that have occurred in the past, including construction of existing infrastructure, as these emissions are not relevant in terms of the actual impacts or emissions that will occur between the present and a specific future date.

In contrast to the approach taken in this study, an attributional LCA approach would instead model electricity infrastructure by allocating construction impacts across the life-span of each type of generation infrastructure. This approach was used, for example, by Saçayon Madrigal (2015) in undertaking an LCA of the New Zealand electricity system in 2013.

The approach taken to modelling of electricity infrastructure in this study is likely to produce different impacts compared with an attributional approach for the following reasons:

- Impacts associated with the construction of existing infrastructure are not considered in the approach taken in this study. For example, generation from existing hydropower schemes currently provides the majority of New Zealand electricity generation and will continue to provide a significant proportion of generation into the future. None of the historical construction impacts associated with this existing infrastructure is considered in this study whereas a proportion of these impacts would be allocated to each unit of hydro generation under an attributional approach.
- The impacts associated with new infrastructure are fully allocated to the year of construction even if the timescale of the LCA study does not include the full lifespan of the infrastructure. For example, in this study all of the construction impacts associated with a wind turbine constructed in 2048 are allocated to the impacts of electricity in the 2018-2050 period but generation from that wind turbine is only considered until the end of the modelling period (2050).
- When using an attributional approach, the allocation of infrastructure reflects the generation mix whereas, in the approach taken in this study, the infrastructure and generation components are not directly linked. For example, under the MBIE scenarios, wind and solar make up the majority of anticipated new capacity infrastructure to be built between 2018 and 2050 but, by 2050, only contribute 11-26% of total annual generation.

The allocation of infrastructure in the manner adopted in this study is clearly not appropriate for assessing the impacts of products with a life-span of only a few years or less as the occurrence of a large infrastructure component in particular years could provide results which are significantly different compared to years with little or no infrastructure construction.

The approach taken in this study may approximate an attributional approach when applied to very long-lived products. But the choice of modelling approach should be determined by the modelling question under consideration as the results obtained by an attributional approach may differ from the results from this study even over a long time period due to differences in the amount and mix of infrastructure between the two methods.

The method adopted in this study is appropriate when undertaking an absolute sustainability assessment when the purpose is to relate the impacts to a future target or limit such as a planetary boundary. In this instance, the timing of emissions and impacts is relevant and the actual emissions that will occur during a specified time period should be considered. Section 8.3 explores the use of the electricity impacts calculated in this study in this context, using a case study of a NZ detached house.

In contrast to the approach adopted for electricity infrastructure, an attributional approach was taken in terms of operational impacts of electricity generation and operational impacts have been based on the average annual generation mix. The ongoing operational impacts are assessed on an attributional basis as the actual or average emissions considering all generation technologies are relevant in a ‘distance to target’ approach rather than the operational emissions of the marginal technology only (Brander et al., 2019).

8.3 New Zealand Detached House Case Study

8.3.1 Goal, Scope and Functional Unit

A case study of a code-compliant New Zealand detached house was undertaken to explore the appropriate use of the electricity impacts calculated in this study. The goal of the case study was to determine the contribution to the New Zealand carbon footprint (CF) from a code compliant detached house during the period from 2020 to 2050. The functional unit was therefore the provision of a New Zealand code compliant house from 2020 to 2050.

The scope of the case study included the following life cycle stages, organised by the following modules as defined in EN 15643-2 (BSI, 2011a):

- Modules A1-A3 - Raw material supply, construction & manufacture;
- Modules A4 – A5 – Transport and installation of construction materials;
- Modules B2 & B4 - Maintenance and replacement of materials during the building service life;
- Module B6 - Operational energy use; and
- Module B7 - Operational water use.

It was assumed that the house was constructed at the beginning of 2020 and would operate for the following 31 years (2020 to 2050). The expected service life of the house is 90 years, therefore the end of life stages (modules C1-C4) and reuse, recovery and recycle potential (module D) were not considered in this assessment as they are primarily relevant to the end of life of the house which would occur outside the time period covered by this case study.

8.3.2 Methodology

The modelled CF of the above life cycle stages over an expected 90 year service life was provided by BRANZ for a code-compliant house with a gross floor area of 194m^2 located in three different temperature zones in New Zealand. The temperature zones can be considered to represent the same house located in Auckland (Zone 1), Wellington (Zone 2) and Christchurch (Zone 3). The CF for all life cycle stages was represented by GWP$_{100}$ excluding biogenic carbon (CML method).

It was assumed the house uses only grid electricity for operational energy requirements (Module B6). The electricity CF for all life cycle stages in the BRANZ analysis was calculated using LCAQuick (BRANZ, 2019a) which uses the Saçayon Madrigal (2015) attributional LCA electricity model (Section 3.1) and the electricity mix from the MBIE (2016) Mixed Renewable scenario.

For the purposes of this case study, the production stage (Modules A1-A3) and construction process (Modules A4-A5) CFs calculated in the original BRANZ analysis were used to represent these cycle stages and the 90 year maintenance and replacement (Modules B2 & B4) and operational water use (Module B7) CFs were pro-rated to represent the 31 year operational period of this case study (i.e. 34.4% of the 90 year CF).

The operational energy use (Module B6) CF was recalculated using the MBIE Global, MBIE Disruptive, and the ICCC 100% Renewable scenarios. The MBIE Global and Disruptive scenarios were selected as these two scenarios represent similar levels of renewable generation (see Section 5.4.1) but the Global scenario represents a low level of generation growth and therefore a low level of new infrastructure construction and the Disruptive scenario represents a high level of generation growth and new infrastructure construction. The ICCC 100%

Renewable scenario was selected as it represents the scenario with the highest amount of renewable generation of the eight scenarios and therefore the lowest operational CF.

The CF of the operational energy use (Module B6) over the 31 years was recalculated using the electricity CFs calculated in this study as follows:

- The CF was based on the GWP_{100} excluding biogenic carbon results.
- The CF per kWh of electricity supplied was calculated by dividing the total annual CF by the annual supply of electricity for each year.
- For the ICCC 100% Renewable scenario, the CF per kWh of supplied electricity for the years 2036-2050 was estimated based on the CF in 2035.
- The calculated total annual CF per kWh of supplied electricity for each year from 2020 to 2050 was multiplied by annual operational energy use data provided by BRANZ. These annual results were summed to provide an operational energy use CF from 2020 to 2050 for each scenario.

It is noted that the CFs calculated in this study should ideally also be applied to electricity used in other life cycle stages of the house for consistency. For example, electricity is used in product manufacture (Modules A1-A3), and maintenance and replacement (Modules B2 & B4). However, data on the electricity component in these other life cycle stages were not readily available, and this represents a limitation of this case study. Another limitation is that pro-rating the maintenance and replacement CFs (Modules B2 & B4) may over-represent this life-cycle stage as a lower than average level of maintenance and replacement would be expected during the first 31 years of the house. The use of GWP_{100} excluding biogenic carbon also means that the CF benefits of carbon sequestration within timber components of the house are not accounted for. Although these limitations may affect the relative importance of different life cycle stages, they are not anticipated to significantly alter the overall conclusions or relative impacts of the different houses as the limitations apply equally to all scenarios.

8.3.3 Results of Housing Case Study

Figure 8.1 shows the CF of the code complaint detached house using the three electricity scenarios in each of the three climate zones. The only difference between the scenarios is the magnitude of the CF for the operational energy use (Module B6) stage of the life cycle; the CFs for the remaining life cycle stages are identical within each climate zone.

The highest CF in each climate zone is obtained using the Disruptive scenario, then the Global scenario, and the 100% Renewable scenario has the lowest CF.

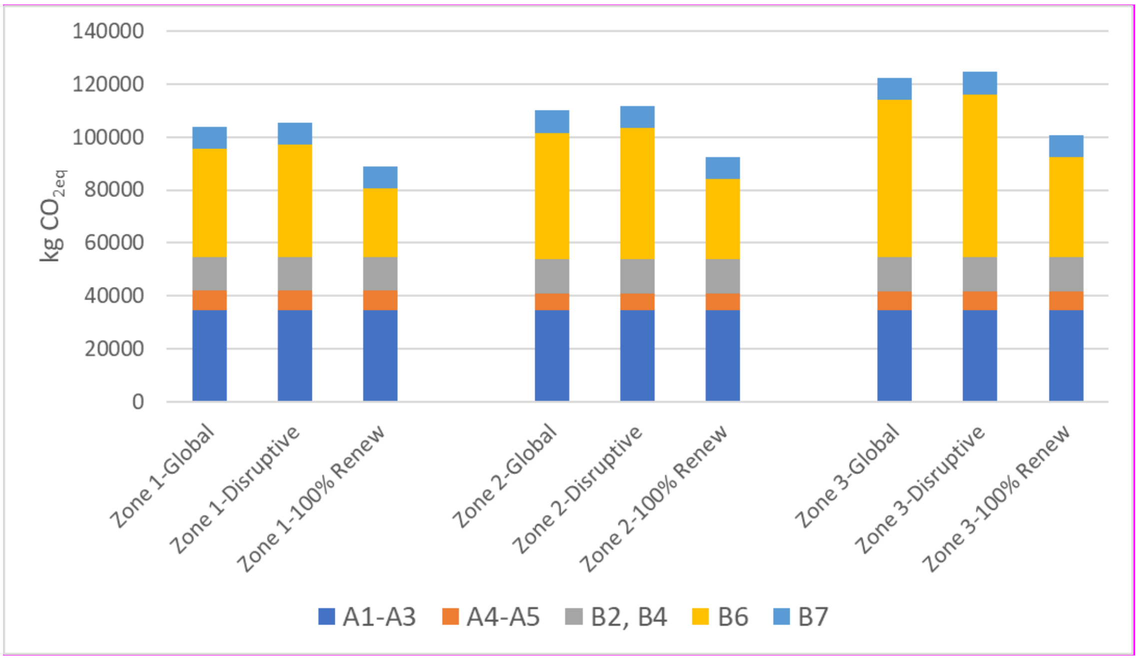

Figure 8.1: Comparison of Life Cycle Carbon Footprint of a New Zealand Code-Compliant House Located in Three Different Temperature Zones (Zone 1=Auckland; Zone 2=Wellington; Zone 3=Christchurch) Based on MBIE Global and Disruptive and ICCC 100% Renewable Future Electricity Generation Scenarios over a 31 Year Study Period (2020-2050)

The use of alternative electricity scenarios also changes the relative contributions of the embodied and operational life cycle stages to the CF. Table 8.1 shows the proportion of embodied impacts associated with each scenario and house. The embodied CF is defined as the CF associated with the A1-A3 (product stage), A4-A5 (construction process) and B2 and B4 (maintenance and replacement) modules. The operational CF is defined as the B6 (operational energy use) and B7 (operational water use) modules for the purposes of this assessment. It can be seen that the embodied CF proportion is similar for the MBIE Global and Disruptive scenarios but higher for the ICCC 100% Renewable scenario.

Table 8.1: Proportion of Carbon Footprint due to Embodied Impacts as a Proportion of the Total Life Cycle Carbon Footprint of a House by Scenario

	MBIE Global	MBIE Disruptive	ICCC 100% Renewable
Zone 1 House	53%	52%	61%
Zone 2 House	49%	48%	58%
Zone 3 House	45%	44%	54%

8.3.4 Discussion of Case Study Results

The choice of future electricity scenario has a significant impact on the calculated CF. In particular, the ICCC 100% Renewable scenario had the lowest CF for all three climate zones. Compared to the 100% Renewable scenario, the MBIE Disruptive and Global scenarios had CFs that were 17-24% higher. This reflects the important contribution of operational electricity impacts to the total carbon footprint with the 100% renewable scenario having the highest renewable content and therefore lowest operational impacts of the three electricity scenarios.

There was a small difference of 1-3% between the MBIE Disruptive and Global scenarios. These two scenarios have similar levels of renewable generation; therefore, the small difference primarily reflects the higher rate of electricity infrastructure construction to meet a higher demand for generation under the Disruptive scenario compared to the lower generation growth under the Global scenario. The small size of the difference between these two scenarios indicates that differences in infrastructure construction do not make a significant contribution to the ranking of the different scenarios in the context of a long-lived product such as a house.

In conclusion, the choice of electricity scenario resulted in a difference in the CF of a code compliant detached house over the study period (2020-2050) of up to 24% and a difference of up to 9% in the proportion of the CF due to embodied impacts. This shows the potentially significant difference that the choice of electricity scenario can have on the CF of a long-lived product where electricity is a significant contributor to the life cycle impacts.

9 Conclusions

9.1 Overview

The research questions that this study aims to address are as follows:

1. What is the environmental profile of the future New Zealand electricity grid mix?
2. Will increased renewable electricity generation in New Zealand enable the electricity sector to meet a climate target consistent with limiting global temperature increase to 1.5°C above pre-industrial levels?
3. How should future grid electricity be modelled in New Zealand LCA studies of long-lived products and activities?

Sections 9.2 to 9.4 address the conclusions of this study in relation to each of these questions. Section 9.5 identifies potential areas for further study. Section 9.6 provides a summary of the study conclusions.

9.2 Environmental Impacts and Benefits of Increased Renewable Generation

Increasing the proportion of renewable generation within the New Zealand electricity mix has clear benefits for most environmental indicators (Sections 6.3.3 and 6.3.4) . The exceptions are ADP elements and ODP which are predominantly determined by the embodied impacts of new generation infrastructure (Section 6.3.1).

The greatest benefits from increased renewable generation are observed in indicators such as the climate change indicators, ADP fossil and PED non-renewable where the impacts are predominantly due to combustion of fossil fuels.

Embodied carbon accounts for 5-12% of the total carbon footprint of New Zealand electricity over the modelling period and this increases to 7-18% of the total carbon footprint during the final 11 years of the MBIE scenarios (Section 6.3.2). There is the potential that embodied carbon may reduce in the future due to decarbonisation of manufacturing processes, but this has not been assessed in this study due to uncertainties around the rate of decarbonisation in countries supplying electricity infrastructure.

The ICCC 100% Renewable scenario results in the lowest carbon footprint of all the scenarios considered. However, the carbon footprint does not reduce to zero once a 100% renewable grid mix is achieved due primarily to geothermal fugitive emissions but also due to the embodied carbon associated with renewable generation infrastructure (Section 6.3.3).

9.3 New Zealand Electricity in the Context of a 1.5°C Climate Target

In this study, the embodied carbon of new generation infrastructure has been fully allocated to the year of construction. This approach is appropriate when considering time specific measures such as a climate change target (Section 8.2). Similarly, the GHG emissions associated with existing infrastructure were emitted at the time of material production and construction and are not relevant to an assessment in relation to a climate target based on GHG emissions occurring between now and a future date.

In the context of a climate change target, it is important to account for the timing of infrastructure impacts as accurately as possible as an exceedance of the identified target may occur during a particular time period necessitating a need to adjust the timing of emissions in order to stay within the identified planetary boundary.

When the electricity system is considered in isolation, none of the future electricity scenarios considered in this study are compatible with limiting climate change to a 1.5°C increase above pre-industrial levels (Section 6.5.1). However, attributing some of the benefits from electrification in the manufacturing and land transport sectors to the electricity sector can result in the electricity sector remaining within a PB compatible with a 1.5°C climate target (Section 6.5.2). This is dependent on the sharing principles used. In some cases, the PB is exceeded for approximately 20 years before reducing to a level below the boundary. This suggests that a more aggressive electrification of manufacturing, transport and other energy users may be required for the energy sector to be compatible with a 1.5°C climate target.

The issue of how the benefits of electrification should be shared highlights the interrelated nature of the energy sector and the need to consider a life cycle approach for the wider energy sector when considering PBs.

9.4 Implications for Incorporating Grid Electricity into NZ LCA Studies

9.4.1 Carbon Accounting Methods

The current study has adopted a life cycle approach to determine the carbon footprint and other impacts associated with New Zealand electricity. There are alternative approaches for assessing the carbon footprint of electricity including the methods used by MBIE (2019b) and MfE (MfE, 2019a, 2019b) for GHG reporting. These methods are based solely on the combustion emissions from fossil fuel generation and fugitive emissions from geothermal generation, which are the most significant GHG emissions associated with electricity generation, but do not account for any emissions associated with wind, solar or hydro generation or the embodied carbon associated with infrastructure. These methods are appropriate for many of the purposes for which they are used such as national GHG reporting and public reporting of GHG emissions in accordance with the reporting requirements of the GHG Protocol for Scope 2 emissions (Sotos, 2015).

A life cycle-based carbon footprint is a more appropriate approach to support decisions where total environmental impacts and benefits are an important consideration. A life cycle approach enables a more comprehensive view of the potential impacts and benefits of different products, activities or services to be taken into consideration. For this reason, a life cycle approach is preferred when used to inform decisions and policy direction regarding the New Zealand electricity sector or to assess the impacts of products where electricity use is an important component.

Figure 9.1 provides a comparison of the carbon footprint for each of the MBIE scenarios over the 2018-2050 modelling period based on fossil fuel combustion and geothermal fugitive emissions (MBIE method) compared to the LCA-based carbon footprint calculated in this study (Section 6.2). Overall, the carbon footprint results calculated using the MBIE method are 37-39% lower than the results using the LCA method. This is due to:

- Different approaches to allocation of emissions associated with cogeneration by auto-producers (i.e. where the electricity is used at the site of generation). The MBIE approach allocates these emissions to the manufacturing sector whereas the LCA-based carbon footprint accounts for these emissions on the basis that cogeneration emissions are equivalent to emissions from a coal or gas electricity only plant.
- The MBIE approach does not account for pre-combustion emissions (e.g. emissions associated with gas and coal production and supply), renewable generation emissions

(e.g. emissions from hydropower reservoirs) and the embodied carbon of new generation and T&D infrastructure.

It could be argued that distributed generation such as generation by auto-producers and residential solar generation should be excluded from the calculation of impacts associated with grid electricity as this generation is predominantly used at the site of generation and is not available to other users of grid electricity. However, the use of distributed generation is essentially displacing other forms of generation that would be required to fulfil the demand for electricity if the distributed generation was not available. Therefore, distributed generation is part of the overall electricity generation and supply system and should be included in an assessment of its environmental impacts. There may be some situations, however, where it is more appropriate to use a subset of the electricity system to represent the environmental impacts of electricity use. For example, the electricity impacts associated with a product produced by an electricity auto-producer may be better represented by the specific impacts of the onsite generation.

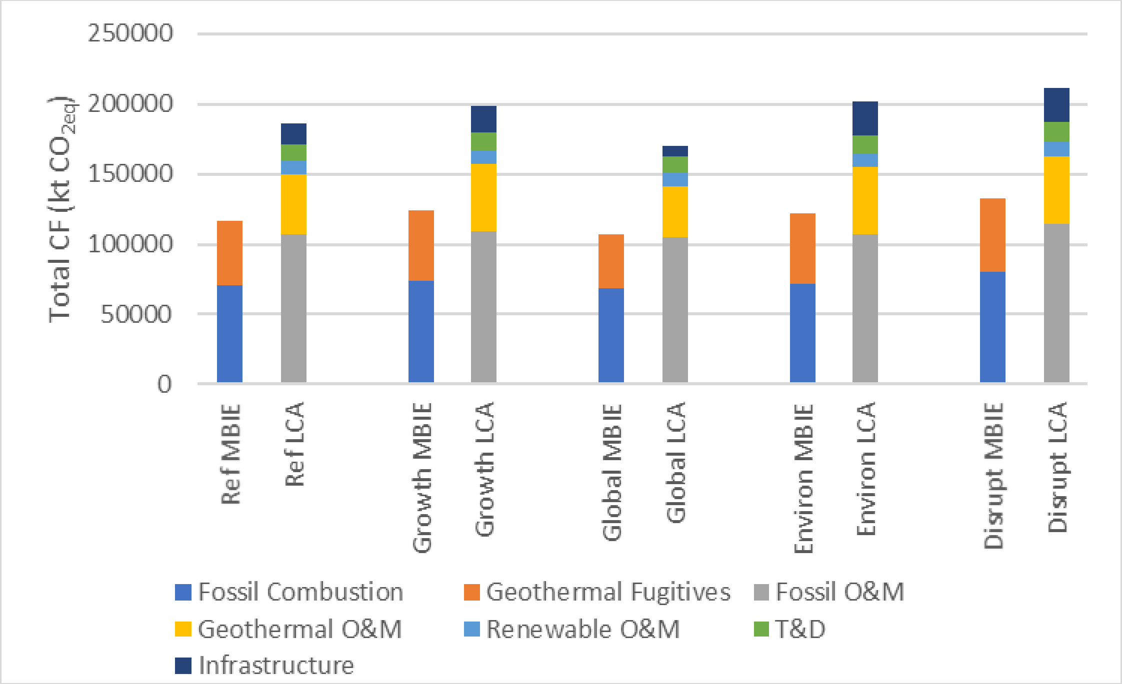

Figure 9.1: Comparison of Total Cumulative Carbon Footprint of MBIE Scenarios (2018-2050) Using Combustion and Fugitive Emissions only (MBIE) versus a Life Cycle Approach (LCA)

9.4.2 Accounting for Infrastructure Impacts

The impacts associated with new generation infrastructure have been fully allocated to the year of construction and the impacts associated with existing infrastructure have not been accounted for in this study (Section 5.8.1). This approach was adopted in order to assess the results with a climate change planetary boundary consistent with limiting global temperature increase to 1.5°C above pre-industrial levels (Section 6.5). It would be appropriate to adopt the results obtained from this study when accounting for the environmental impacts of New Zealand electricity when undertaking an absolute sustainability LCA of a long-lived product.

When undertaking a relative LCA, it would be more appropriate to use an attributional approach for electricity impacts with the impacts of both existing and new infrastructure spread over the lifetime of the relevant generation technology. An attributional approach avoids the results being influenced by differences in the timing of when infrastructure is constructed as the timing of emissions is less relevant in a relative LCA as compared to a distance to target assessment.

9.4.3 Choice of Electricity Scenario

A case study of a New Zealand detached house (Section 8.3) demonstrated that the choice of future electricity scenario can have a significant impact on the life cycle impacts of long-lived products that consume electricity with life cycle impacts varying by up to 24% depending on the electricity scenario used.

The MBIE scenarios provide more conservative results than the ICCC scenarios due largely to the greater proportion of coal in the generation mix under the MBIE scenarios (Section 5.4.1). The use of a particular scenario to represent electricity supply in future focused LCA studies will be influenced by the scope of the study and nature of the product or service under consideration. The MBIE Reference scenario represents a conservative scenario and is recommended as the most appropriate scenario to use as a base-case. Other scenarios could be used as part of a sensitivity analysis to explore the range of possible results. For example, the ICCC 100% Renewable scenario represents a low level of impact for impact categories strongly influenced by operational impacts. In contrast, the MBIE Disruptive scenario represents a scenario with relatively high levels of both generation demand and construction of new generation infrastructure and therefore represents a high level of impact for impact categories strongly influenced by infrastructure impacts.

9.5 Potential Areas for Further Study

The study has highlighted a number of areas where further investigation would improve the robustness of assumptions or potentially lead to a better understanding of how to reduce the impacts associated with New Zealand electricity. Areas for further study include the following:

- Solar generation infrastructure: quantification of the New Zealand specific life cycle impacts associated with distributed solar generation infrastructure including current and future technology mix, and the source and resulting impacts of raw materials and components.

- Cogeneration facilities: collation of data on the efficiency and relative production of heat and electricity of different cogeneration facilities; projections of future generation from these facilities; and reconsideration of the treatment of auto-producer emissions for reporting purposes.

- Geothermal generation: fugitive emissions become an increasingly important part of the New Zealand generation mix over time. Further study to accurately quantify the size and range of geothermal fugitive emissions would improve the accuracy of assumptions and also potentially identify areas for emission reduction. Studies of potential technological or operational measure to reduce the carbon footprint of geothermal generation have the potential to significantly improve the overall carbon footprint of New Zealand electricity.

- Planetary Boundaries: a PB assessment of the New Zealand energy sector as a whole would help determine whether current pathways and policy settings are sufficient to meet climate change aspirations. This requires additional information on the net benefits and impacts of electrification in the manufacturing and transport sectors using a life cycle approach. Up to date data on the total consumption based GHG emissions of New Zealand would provide more accurate data for calculating carbon budgets on a grandfathered basis.

9.6 Summary

All eight of the future electricity scenarios considered in this study assume an increasing proportion of renewable generation in the New Zealand electricity grid mix which results in environmental benefits in most of the impact categories considered including the climate change indicators. However, even with 100% renewable generation, the carbon footprint of electricity does not reduce to zero due primarily to the GHG emissions associated with geothermal generation and also the embodied carbon associated with new renewable generation infrastructure.

When the New Zealand electricity system is considered in isolation, none of the future electricity scenarios considered are compatible with limiting climate change to a 1.5°C increase above pre-industrial levels. However, attributing some of the benefits from electrification in the manufacturing and land transport sectors to the electricity sector can result in the electricity sector remaining within a PB compatible with a 1.5°C climate target depending on the sharing principles used.

A life-cycle approach provides a more complete representation of the impacts associated with electricity use compared to considering only the operational emissions of electricity generation.

A case study of a New Zealand detached house demonstrated that the choice of future electricity scenario can have a significant impact on the magnitude of the life cycle impacts of this particular long-lived product with the carbon footprint varying by up to 24% depending on the electricity scenario used.

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Appendix A: Abbreviations

ADP elements	abiotic depletion potential - elements
ADP fossil	abiotic depletion potential – fossil fuels
ADP	abiotic depletion potential
AP	acidification potential
CB	carbon budget
CCS	carbon capture and sequestration
CEPA	carbon emissions pinch analysis
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
CO_{2eq}	carbon dioxide equivalent
EP	eutrophication potential
EPD	environmental product declaration
EROC	energy return on carbon emissions
EROI	energy return on investment
FAETP	freshwater aquatic ecotoxicity potential
GDP	gross domestic product
GHG	greenhouse gas
GTP	global temperature change potential
GVA	gross value added
GWh	gigawatt hour
GWP	global warming potential
H_2S	hydrogen sulphide
HTP	human toxicity potential
HVAC	high voltage alternating current
HVDC	high voltage direct current
ICCC	Interim Climate Change Committee
ILCD	International Reference Life Cycle Data System
IPCC	Intergovernmental Panel on Climate Change
kj	kilojoules

km	kilometre
kV	kilovolt
kWh	kilowatt hour
LCA	life cycle assessment
LCI	life cycle inventory
LCIA	life cycle impact assessment
LEPR	life cycle energy payback ratio
MAETP	marine aquatic ecotoxicity potential
MBIE	Ministry of Business, Innovation and Employment
MD	metal depletion
Mt	megatonne
MW	megawatt
MWh	megawatt hour
N_2O	nitrous oxide
NGCC	natural gas combined cycle
NGCT	natural gas combustion turbine
NH_3	ammonia
NMVOC	non-methane volatile organic compounds
NO_x	nitrogen oxides
nREn	non-renewable fossil energy demand
NTCF	near-term climate forcers
O&M	operation and maintenance
O_3	ozone
ODP	ozone layer depletion potential
PB	planetary boundary
PED non-renew	primary energy demand from non-renewable resources
PED renew	primary energy demand from renewable resources
PED total	primary energy demand from renewable and non-renewable resources
PMF	particulate matter formation
PO	photochemical oxidation
POCP	photochemical ozone creation potential

PV	photovoltaic
PVC	polyvinylchloride
SF_6	sulphur hexafluoride
SO_2	sulphur dioxide
T&D	transmission and distribution
TETP	terrestrial ecotoxicity potential
Tg	teragram
TWh	terawatt hour
WMGHG	well mixed greenhouse gases

Appendix B: Assumptions and Key Modelling Results of ICCC and MBIE Future Generation Scenario Modelling

Table B1: Summary of ICCC Scenario Modelling Assumptions (Source: ICCC, 2019)

Assumption (by 2035)	Unit	Scenario		
		Business as Usual (BAU)	**100% Renewable**	**Accelerated Electrification**
Underlying Demand Growth	%/year	0.5	0.5	0.5
Electric Vehicle Demand Increase	TWh	2.7	2.7	5.7
Process Heat Demand Increase	TWh	0.6	0.6	5.5
Overall Demand	TWh	49	49	57
Battery Deployment	MW	200	850	500
Rooftop Solar	TWh	1.2		
Large Scale Solar Cost	\$/MWh	81		
Wind Cost	\$/MWh	66		
Natural Gas Price	\$/GJ	9.50		
Emissions Price	\$/t CO_{2eq}	50		

Table B2: Summary of MBIE Scenario Modelling Assumptions Source: MBIE (2019b)

Assumption	Scenario				
	Reference	Growth	Global	Environmental	Disruptive
Labour productivity	1.1% per annum	1.5% per annum	0.7% per annum	Same as Reference	Same as Reference
Population	50th percentile	90th percentile	10th percentile	Same as Reference	Same as Reference
Exchange rates NZD/USD	0.65				
Real discount rate	6%				
Residential energy intensity	Decrease by 2030, then flat	Same as Reference	Same as Reference	Same as Reference	Decrease by 2040, then flat
Process heat electrification by 2050	~15% (low only)	Same as Reference	Same as Reference	~55% (low and medium)	~83% (low, medium, & high)
Electric vehicles uptake	Moderate	Adjusted for higher GDP	Adjusted for lower GDP	High, due to interventions	High due to technology
Residential solar generation	Moderate	Adjusted for GDP	Adjusted for GDP and Prices	High	High
Wind LRMC $/MWh	2019: ~$75 2050: ~$65	Same as Reference	2019: ~$75 2050:~$70	Same as Reference	2019: ~$75 2050: ~$55
Grid solar LRMC $/MWh	2019: ~$130 2040: ~$70 2050:~$65	Same as Reference	Same as Reference	Same as Reference	2019: ~$110 2035: ~$65 2050:~$60
Carbon price USD$/tCO$_2$	2040: $38 2050: $43	Same as Reference	Same as Reference	2040: $73 2050: $100	Same as Reference

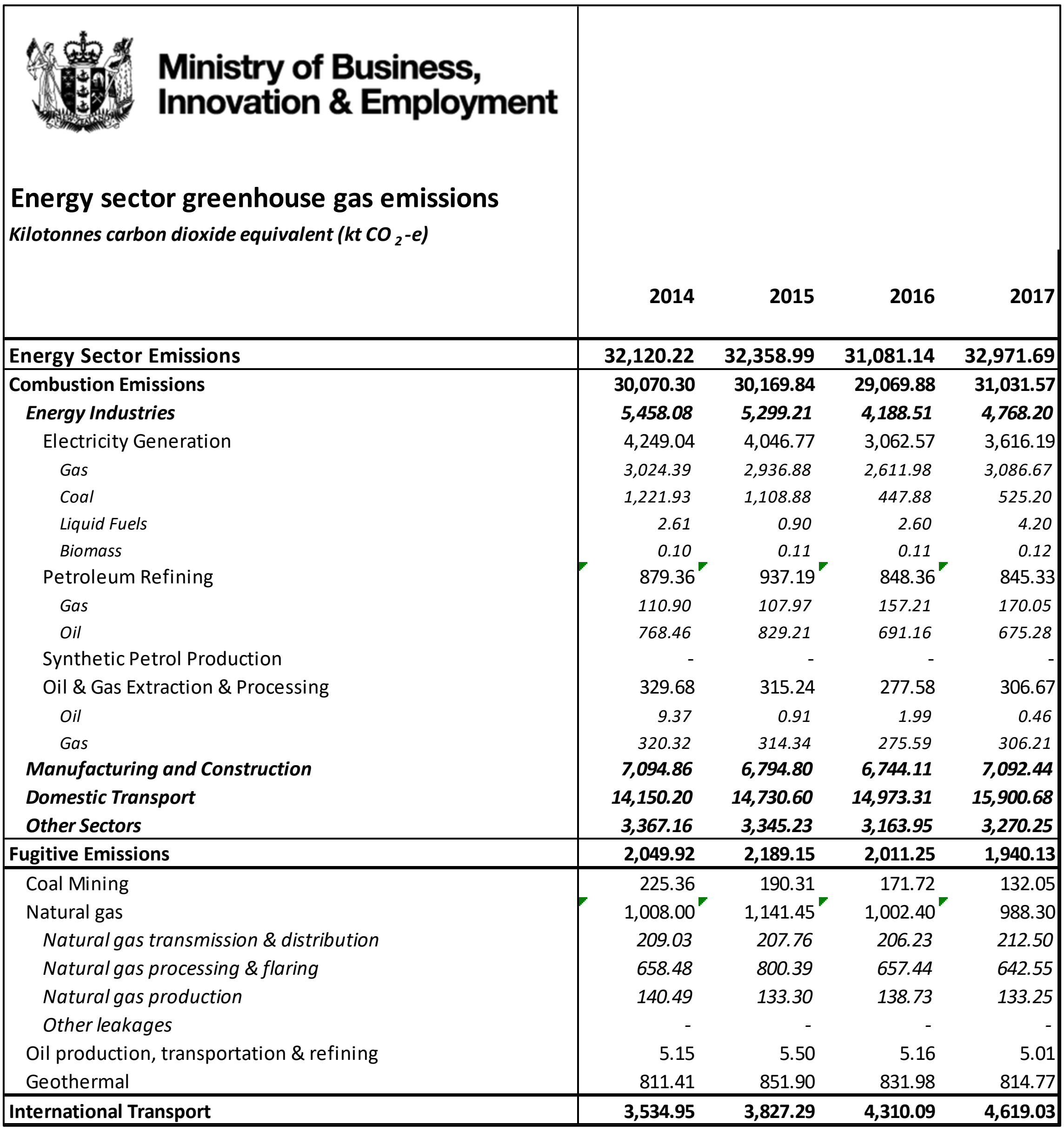
Table B3: Summary of Key Scenario Modelling Results at 2050 Source: MBIE (2019b)

Variable	**Scenario**				
	Reference	**Growth**	**Global**	**Environmental**	**Disruptive**
Electricity Demand					
Total (TWh)	57 (+43%)	65 (+64%)	47 (+18%)	67 (+68%)	71 (+78%)
Process heat (TWh)	1.5	1.9	1.2	6.5	13.3
Electric vehicles (TWh)	4.1	5.0	3.2	7.6	7.6
Peak demand (GW)	8.5 (+34%)	9.8 (+56%)	7.1 (+12%)	9.6 (+53%)	10.2 (+62%)
Generation					
New capacity (MW)	6,300	9,400	3,800	9,600	10,600
Roof-top solar (TWh)	2.3	2.8	0.9	4.6	4.6
Renewables (%)	94.9	95.4	94.8	96.0	94.9
Energy sector greenhouse gases (2017 value = 32.9 Mt CO_2eq)					
Emissions (Mt CO_2eq)	23.7 (-28%)	26.7 (-19%)	19.6 (-40%)	17.2 (-48%)	16.9 (-48%)

Appendix C: MBIE Energy Sector Emissions Tables

Source: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/new-zealand-energy-sector-greenhouse-gas-emissions/

Table C1: New Zealand Energy Sector CO_2 Equivalent Emissions



Ministry of Business, Innovation & Employment

Energy sector greenhouse gas emissions

Kilotonnes carbon dioxide equivalent (kt CO_2-e)

	2014	2015	2016	2017
Energy Sector Emissions	**32,120.22**	**32,358.99**	**31,081.14**	**32,971.69**
Combustion Emissions	**30,070.30**	**30,169.84**	**29,069.88**	**31,031.57**
Energy Industries	***5,458.08***	***5,299.21***	***4,188.51***	***4,768.20***
Electricity Generation	4,249.04	4,046.77	3,062.57	3,616.19
Gas	*3,024.39*	*2,936.88*	*2,611.98*	*3,086.67*
Coal	*1,221.93*	*1,108.88*	*447.88*	*525.20*
Liquid Fuels	*2.61*	*0.90*	*2.60*	*4.20*
Biomass	*0.10*	*0.11*	*0.11*	*0.12*
Petroleum Refining	879.36	937.19	848.36	845.33
Gas	*110.90*	*107.97*	*157.21*	*170.05*
Oil	*768.46*	*829.21*	*691.16*	*675.28*
Synthetic Petrol Production	-	-	-	-
Oil & Gas Extraction & Processing	329.68	315.24	277.58	306.67
Oil	*9.37*	*0.91*	*1.99*	*0.46*
Gas	*320.32*	*314.34*	*275.59*	*306.21*
Manufacturing and Construction	***7,094.86***	***6,794.80***	***6,744.11***	***7,092.44***
Domestic Transport	***14,150.20***	***14,730.60***	***14,973.31***	***15,900.68***
Other Sectors	***3,367.16***	***3,345.23***	***3,163.95***	***3,270.25***
Fugitive Emissions	**2,049.92**	**2,189.15**	**2,011.25**	**1,940.13**
Coal Mining	225.36	190.31	171.72	132.05
Natural gas	1,008.00	1,141.45	1,002.40	988.30
Natural gas transmission & distribution	*209.03*	*207.76*	*206.23*	*212.50*
Natural gas processing & flaring	*658.48*	*800.39*	*657.44*	*642.55*
Natural gas production	*140.49*	*133.30*	*138.73*	*133.25*
Other leakages	-	-	-	-
Oil production, transportation & refining	5.15	5.50	5.16	5.01
Geothermal	811.41	851.90	831.98	814.77
International Transport	**3,534.95**	**3,827.29**	**4,310.09**	**4,619.03**

Table C2: New Zealand Energy Sector CO_2 Emissions

Ministry of Business, Innovation & Employment

Energy sector greenhouse gas emissions

Kilotonnes carbon dioxide (kt CO_2)

	2014	2015	2016	2017
Energy Sector Emissions	**30,921.57**	**31,142.50**	**29,930.19**	**31,851.39**
Combustion Emissions	**29,670.29**	**29,771.34**	**28,687.85**	**30,652.03**
Energy Industries	***5,447.91***	***5,289.62***	***4,182.46***	***4,761.43***
Electricity Generation	4,240.20	4,038.57	3,057.90	3,610.68
Gas	*3,021.59*	*2,934.17*	*2,609.60*	*3,083.84*
Coal	*1,216.00*	*1,103.50*	*445.70*	*522.66*
Liquid Fuels	*2.61*	*0.90*	*2.59*	*4.18*
Biomass	*103.06*	*110.54*	*113.79*	*119.54*
Petroleum Refining	878.36	936.09	847.24	844.36
Gas	*110.80*	*107.87*	*157.06*	*169.90*
Oil	*767.56*	*828.22*	*690.18*	*674.46*
Synthetic Petrol Production	-	-	-	-
Oil & Gas Extraction & Processing	329.35	314.95	277.32	306.39
Oil	*9.34*	*0.91*	*1.98*	*0.46*
Gas	*320.02*	*314.05*	*275.34*	*305.93*
Manufacturing and Construction	***6,987.79***	***6,686.53***	***6,638.41***	***6,978.29***
Domestic Transport	***13,974.28***	***14,559.55***	***14,806.06***	***15,754.84***
Other Sectors	***3,260.30***	***3,235.65***	***3,060.92***	***3,157.47***
Fugitive Emissions	**1,251.28**	**1,371.16**	**1,242.34**	**1,199.35**
Coal Mining	-	-	-	-
Natural gas	605.77	695.46	583.19	556.08
Natural gas transmission & distribution	*1.28*	*1.26*	*1.25*	*1.30*
Natural gas processing & flaring	*604.29*	*694.01*	*581.74*	*554.60*
Natural gas production	*0.20*	*0.19*	*0.20*	*0.19*
Other leakages	-	-	-	-
Oil production, transportation & refining	0.01	0.01	0.01	0.01
Geothermal	645.51	675.69	659.15	643.26
International Transport	**3,502.90**	**3,792.92**	**4,271.52**	**4,578.04**

Table C3: New Zealand Energy Sector CH_4 Emissions

Ministry of Business, Innovation & Employment

Energy sector greenhouse gas emissions

Kilotonnes methane (kt CH_4)

	2014	2015	2016	2017
Energy Sector Emissions	**37.56**	**38.48**	**36.19**	**35.45**
Combustion Emissions	**5.62**	**5.77**	**5.44**	**5.83**
Energy Industries	***0.09***	***0.09***	***0.07***	***0.08***
Electricity Generation	0.07	0.06	0.05	0.06
Gas	*0.05*	*0.05*	*0.04*	*0.05*
Coal	*0.01*	*0.01*	*0.00*	*0.01*
Liquid Fuels	*0.00*	*0.00*	*0.00*	*0.00*
Biomass	*0.00*	*0.00*	*0.00*	*0.00*
Petroleum Refining	0.02	0.02	0.02	0.02
Gas	*0.00*	*0.00*	*0.00*	*0.00*
Oil	*0.01*	*0.02*	*0.01*	*0.01*
Synthetic Petrol Production	-	-	-	-
Oil & Gas Extraction & Processing	0.01	0.01	0.00	0.01
Oil	*0.00*	*0.00*	*0.00*	*0.00*
Gas	*0.01*	*0.01*	*0.00*	*0.01*
Manufacturing and Construction	***1.54***	***1.56***	***1.53***	***1.64***
Domestic Transport	***1.14***	***1.11***	***1.07***	***0.90***
Other Sectors	***2.85***	***3.01***	***2.77***	***3.21***
Fugitive Emissions	**31.94**	**32.71**	**30.75**	**29.63**
Coal Mining	9.01	7.61	6.87	5.28
Natural gas	16.09	17.83	16.76	17.28
Natural gas transmission & distribution	*8.31*	*8.26*	*8.20*	*8.45*
Natural gas processing & flaring	*2.16*	*4.25*	*3.02*	*3.51*
Natural gas production	*5.61*	*5.32*	*5.54*	*5.32*
Other leakages	*-*	*-*	*-*	*-*
Oil production, transportation & refining	0.21	0.22	0.21	0.20
Geothermal	6.64	7.05	6.91	6.86
International Transport	**0.10**	**0.11**	**0.10**	**0.10**

Table C4: New Zealand Energy Sector N_2O Emissions

Ministry of Business, Innovation & Employment **Energy sector greenhouse gas emissions** ***Kilotonnes nitrous oxide (kt N_2O)***	**2014**	**2015**	**2016**	**2017**
Energy Sector Emissions	**0.87**	**0.85**	**0.83**	**0.78**
Combustion Emissions	**0.87**	**0.85**	**0.83**	**0.78**
Energy Industries	***0.03***	***0.03***	***0.01***	***0.02***
Electricity Generation	0.02	0.02	0.01	0.01
Gas	*0.01*	*0.00*	*0.00*	*0.01*
Coal	*0.02*	*0.02*	*0.01*	*0.01*
Liquid Fuels	*0.00*	*0.00*	*0.00*	*0.00*
Biomass	*0.00*	*0.00*	*0.00*	*0.00*
Petroleum Refining	0.00	0.00	0.00	0.00
Gas	*0.00*	*0.00*	*0.00*	*0.00*
Oil	*0.00*	*0.00*	*0.00*	*0.00*
Synthetic Petrol Production	-	-	-	-
Oil & Gas Extraction & Processing	0.00	0.00	0.00	0.00
Oil	*0.00*	*0.00*	*0.00*	*0.00*
Gas	*0.00*	*0.00*	*0.00*	*0.00*
Manufacturing and Construction	***0.23***	***0.23***	***0.23***	***0.25***
Domestic Transport	***0.49***	***0.48***	***0.47***	***0.41***
Other Sectors	***0.12***	***0.11***	***0.11***	***0.11***
Fugitive Emissions	**0.00**	**0.00**	**0.00**	**0.00**
Coal Mining	-	-	-	-
Natural gas	0.00	0.00	0.00	0.00
Natural gas transmission & distribution	-	-	-	-
Natural gas processing & flaring	*0.00*	*0.00*	*0.00*	*0.00*
Natural gas production	-	-	-	-
Other leakages	-	-	-	-
Oil production, transportation & refining	-	-	-	-
Geothermal	-	-	-	-
International Transport	**0.10**	**0.11**	**0.12**	**0.13**

Table C5: New Zealand Energy Sector CO Emissions

Ministry of Business, Innovation & Employment

Energy sector greenhouse gas emissions

Kilotonnes carbon monoxide (kt CO)

	2014	2015	2016	2017
Energy Sector Emissions	**645.96**	**662.55**	**676.09**	**692.02**
Combustion Emissions	**645.96**	**662.55**	**676.09**	**692.02**
Energy Industries	***2.10***	***2.04***	***1.75***	***2.04***
Electricity Generation	1.77	1.70	1.45	1.73
Gas	*1.64*	*1.58*	*1.39*	*1.66*
Coal	*0.11*	*0.10*	*0.04*	*0.05*
Liquid Fuels	*0.00*	*0.00*	*0.00*	*0.00*
Biomass	*0.02*	*0.02*	*0.02*	*0.02*
Petroleum Refining	0.23	0.24	0.22	0.23
Gas	*0.03*	*0.03*	*0.05*	*0.05*
Oil	*0.19*	*0.21*	*0.17*	*0.17*
Synthetic Petrol Production	-	-	-	-
Oil & Gas Extraction & Processing	0.10	0.10	0.08	0.09
Oil	*0.00*	*0.00*	*0.00*	*0.00*
Gas	*0.10*	*0.10*	*0.08*	*0.09*
Manufacturing and Construction	***32.24***	***33.55***	***33.33***	***34.45***
Domestic Transport	***507.50***	***522.77***	***534.99***	***549.58***
Other Sectors	***104.13***	***104.19***	***106.01***	***105.95***
Fugitive Emissions	**-**	**-**	**-**	**-**
Coal Mining	-	-	-	-
Natural gas	-	-	-	-
Natural gas transmission & distribution	-	-	-	-
Natural gas processing & flaring	-	-	-	-
Natural gas production	-	-	-	-
Other leakages	-	-	-	-
Oil production, transportation & refining	-	-	-	-
Geothermal	-	-	-	-
International Transport	**6.74**	**7.22**	**8.03**	**8.49**

Table C6: New Zealand Energy Sector NO_x Emissions

Ministry of Business, Innovation & Employment

Energy sector greenhouse gas emissions

Kilotonnes nitrogen oxides (kt NO_x)

	2014	2015	2016	2017
Energy Sector Emissions	**157.64**	**159.54**	**153.19**	**164.10**
Combustion Emissions	**157.64**	**159.54**	**153.19**	**164.10**
Energy Industries	***20.61***	***19.94***	***15.53***	***17.91***
Electricity Generation	16.11	15.30	11.40	13.54
Petroleum Refining	3.12	3.32	2.97	3.09
Synthetic Petrol Production	-	-	-	-
Oil & Gas Extraction & Processing	1.38	1.33	1.16	1.28
Manufacturing and Construction	***31.39***	***30.00***	***29.77***	***31.93***
Domestic Transport	***86.87***	***92.52***	***91.79***	***99.45***
Other Sectors	***18.77***	***17.07***	***16.10***	***14.81***
Fugitive Emissions	**-**	**-**	**-**	**-**
Coal Mining	-	-	-	-
Natural gas	-	-	-	-
Oil production, transportation & refining	-	-	-	-
Geothermal	-	-	-	-
International Transport	**29.85**	**33.38**	**33.84**	**34.17**

Table C7: New Zealand Energy Sector NMVOC Emissions

Ministry of Business,
Innovation & Employment

Energy sector greenhouse gas emissions

Kilotonnes non-methane volatile organic compounds (kt NMVOCs)

	2014	2015	2016	2017
Energy Sector Emissions	**131.78**	**135.76**	**138.13**	**141.70**
Combustion Emissions	**114.99**	**118.20**	**120.59**	**124.00**
Energy Industries	***0.42***	***0.41***	***0.34***	***0.39***
Electricity Generation	0.33	0.31	0.25	0.30
Gas	*0.26*	*0.25*	*0.22*	*0.26*
Coal	*0.06*	*0.06*	*0.02*	*0.03*
Liquid Fuels	*0.00*	*0.00*	*0.00*	*0.00*
Biomass	*0.01*	*0.01*	*0.01*	*0.01*
Petroleum Refining	0.06	0.07	0.06	0.06
Gas	*0.01*	*0.01*	*0.01*	*0.01*
Oil	*0.06*	*0.06*	*0.05*	*0.05*
Synthetic Petrol Production	-	-	-	-
Oil & Gas Extraction & Processing	0.03	0.03	0.02	0.03
Oil	*0.00*	*0.00*	*0.00*	*0.00*
Gas	*0.03*	*0.03*	*0.02*	*0.03*
Manufacturing and Construction	***3.94***	***4.15***	***4.14***	***4.27***
Domestic Transport	***101.57***	***104.70***	***107.10***	***110.32***
Other Sectors	***9.06***	***8.94***	***9.01***	***9.03***
Fugitive Emissions	**16.79**	**17.56**	**17.55**	**17.70**
Coal Mining	-	-	-	-
Natural gas	1.34	1.27	1.33	1.27
Natural gas transmission & distribution	*0.00*	*0.00*	*0.00*	*0.00*
Natural gas processing & flaring	-	-	-	-
Natural gas production	*1.34*	*1.27*	*1.33*	*1.27*
Other leakages	-	-	-	-
Oil production, transportation & refining	15.45	16.29	16.22	16.42
Geothermal	-	-	-	-
International Transport	**1.38**	**1.47**	**1.58**	**1.62**

Table C8: New Zealand Energy Sector SO_2 Emissions

Ministry of Business, Innovation & Employment

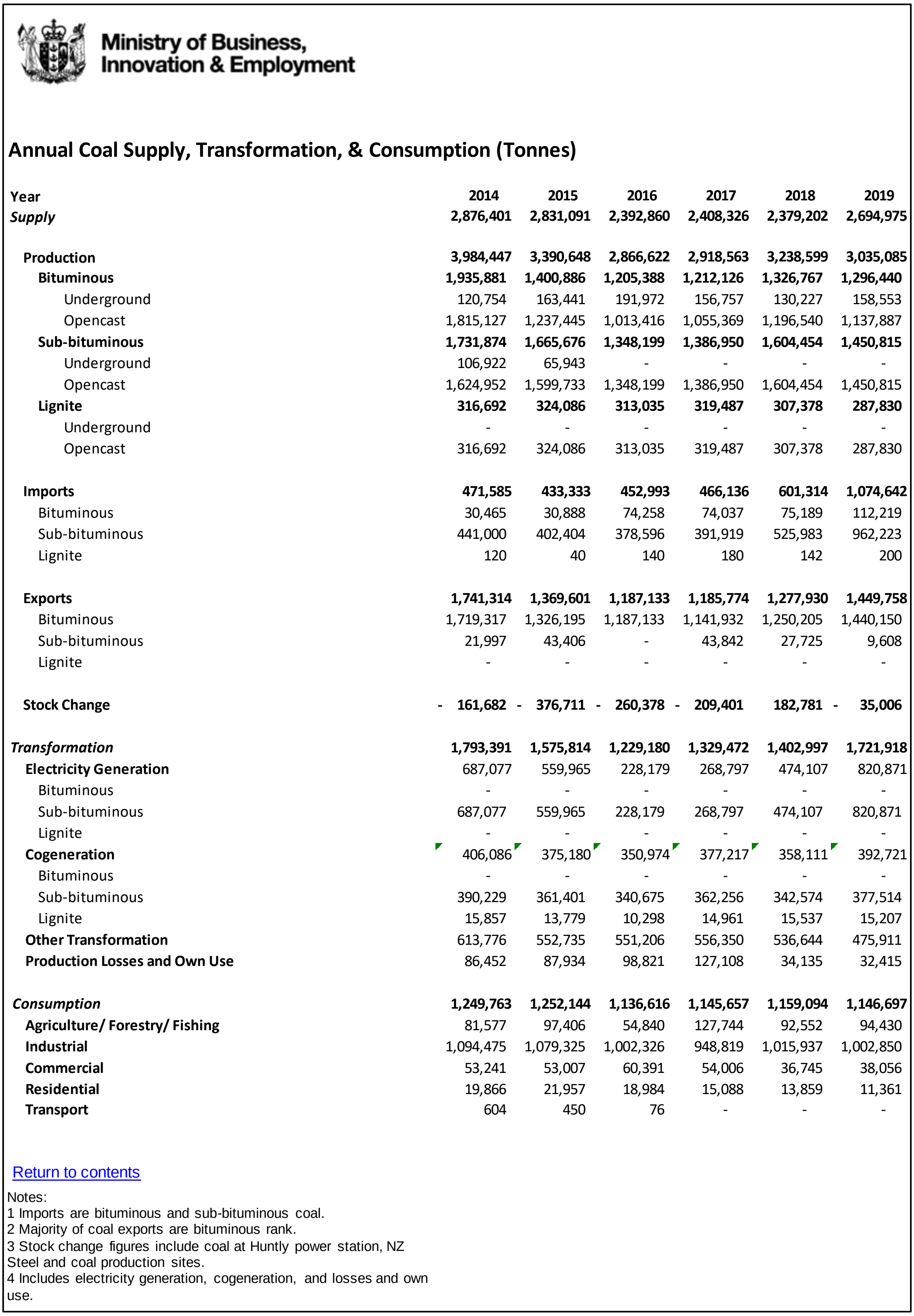
Energy sector greenhouse gas emissions

Kilotonnes sulphur dioxide (kt SO_2)

	2014	2015	2016	2017
Energy Sector Emissions	**62.59**	**64.64**	**58.65**	**62.80**
Combustion Emissions	**57.99**	**59.84**	**53.56**	**57.31**
Energy Industries	***7.84***	***8.34***	***5.11***	***4.87***
Electricity Generation	5.12	4.65	1.88	2.21
Gas	-	-	-	-
Coal	*5.12*	*4.64*	*1.88*	*2.20*
Liquid Fuels	*0.00*	*0.00*	*0.00*	*0.01*
Biomass	-	-	-	-
Petroleum Refining	2.71	3.70	3.23	2.67
Gas	-	-	-	-
Oil	*2.71*	*3.70*	*3.23*	*2.67*
Synthetic Petrol Production	-	-	-	-
Oil & Gas Extraction & Processing	0.01	0.00	0.00	0.00
Oil	*0.01*	*0.00*	*0.00*	*0.00*
Gas	-	-	-	-
Manufacturing and Construction	***29.12***	***29.07***	***28.02***	***30.54***
Domestic Transport	***12.90***	***14.78***	***13.28***	***14.61***
Other Sectors	***8.12***	***7.65***	***7.15***	***7.29***
Fugitive Emissions	**4.60**	**4.80**	**5.09**	**5.49**
Coal Mining	-	-	-	-
Natural gas	-	-	-	-
Natural gas transmission & distribution	-	-	-	-
Natural gas processing & flaring	-	-	-	-
Natural gas production	-	-	-	-
Other leakages	-	-	-	-
Oil production, transportation & refining	4.60	4.80	5.09	5.49
Geothermal	-	-	-	-
International Transport	**11.45**	**13.30**	**12.16**	**11.54**

Appendix D: MBIE Data Tables for Coal

Source: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/coal-statistics/



Ministry of Business, Innovation & Employment

Annual Coal Supply, Transformation, & Consumption (Tonnes)

Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Supply	**2,876,401**	**2,831,091**	**2,392,860**	**2,408,326**	**2,379,202**	**2,694,975**
Production	**3,984,447**	**3,390,648**	**2,866,622**	**2,918,563**	**3,238,599**	**3,035,085**
Bituminous	**1,935,881**	**1,400,886**	**1,205,388**	**1,212,126**	**1,326,767**	**1,296,440**
Underground	120,754	163,441	191,972	156,757	130,227	158,553
Opencast	1,815,127	1,237,445	1,013,416	1,055,369	1,196,540	1,137,887
Sub-bituminous	**1,731,874**	**1,665,676**	**1,348,199**	**1,386,950**	**1,604,454**	**1,450,815**
Underground	106,922	65,943	-	-	-	-
Opencast	1,624,952	1,599,733	1,348,199	1,386,950	1,604,454	1,450,815
Lignite	**316,692**	**324,086**	**313,035**	**319,487**	**307,378**	**287,830**
Underground	-	-	-	-	-	-
Opencast	316,692	324,086	313,035	319,487	307,378	287,830
Imports	**471,585**	**433,333**	**452,993**	**466,136**	**601,314**	**1,074,642**
Bituminous	30,465	30,888	74,258	74,037	75,189	112,219
Sub-bituminous	441,000	402,404	378,596	391,919	525,983	962,223
Lignite	120	40	140	180	142	200
Exports	**1,741,314**	**1,369,601**	**1,187,133**	**1,185,774**	**1,277,930**	**1,449,758**
Bituminous	1,719,317	1,326,195	1,187,133	1,141,932	1,250,205	1,440,150
Sub-bituminous	21,997	43,406	-	43,842	27,725	9,608
Lignite	-	-	-	-	-	-
Stock Change	**- 161,682**	**- 376,711**	**- 260,378**	**- 209,401**	**182,781**	**- 35,006**
Transformation	**1,793,391**	**1,575,814**	**1,229,180**	**1,329,472**	**1,402,997**	**1,721,918**
Electricity Generation	687,077	559,965	228,179	268,797	474,107	820,871
Bituminous	-	-	-	-	-	-
Sub-bituminous	687,077	559,965	228,179	268,797	474,107	820,871
Lignite	-	-	-	-	-	-
Cogeneration	406,086	375,180	350,974	377,217	358,111	392,721
Bituminous	-	-	-	-	-	-
Sub-bituminous	390,229	361,401	340,675	362,256	342,574	377,514
Lignite	15,857	13,779	10,298	14,961	15,537	15,207
Other Transformation	613,776	552,735	551,206	556,350	536,644	475,911
Production Losses and Own Use	86,452	87,934	98,821	127,108	34,135	32,415
Consumption	**1,249,763**	**1,252,144**	**1,136,616**	**1,145,657**	**1,159,094**	**1,146,697**
Agriculture/ Forestry/ Fishing	81,577	97,406	54,840	127,744	92,552	94,430
Industrial	1,094,475	1,079,325	1,002,326	948,819	1,015,937	1,002,850
Commercial	53,241	53,007	60,391	54,006	36,745	38,056
Residential	19,866	21,957	18,984	15,088	13,859	11,361
Transport	604	450	76	-	-	-

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Notes:
1 Imports are bituminous and sub-bituminous coal.
2 Majority of coal exports are bituminous rank.
3 Stock change figures include coal at Huntly power station, NZ Steel and coal production sites.
4 Includes electricity generation, cogeneration, and losses and own use.

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Annual Coal Supply, Transformation, & Consumption (PJ)

Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Supply	**61.34**	**59.85**	**50.47**	**50.98**	**50.62**	**57.68**
Production	**103.31**	**85.34**	**71.57**	**72.45**	**80.54**	**75.84**
Bituminous	61.09	44.44	38.36	37.83	40.38	39.35
Sub-bituminous	37.38	35.96	28.43	29.20	34.63	31.29
Lignite	4.83	4.94	4.78	5.42	5.53	5.19
Imports	**9.40**	**9.53**	**10.07**	**10.36**	**13.32**	**24.16**
Bituminous	0.91	0.91	2.03	2.07	2.14	3.41
Sub-bituminous	8.48	8.62	8.04	8.28	11.18	20.75
Lignite	0.00	0.00	0.00	0.00	0.00	0.00
Exports	**54.88**	**43.05**	**37.84**	**36.69**	**38.52**	**43.92**
Bituminous	54.46	42.12	37.84	35.76	37.94	43.72
Sub-bituminous	0.42	0.93	0.00	0.93	0.59	0.21
Lignite	0.00	0.00	0.00	0.00	0.00	0.00
Stock Change	**-3.51**	**-8.02**	**-6.67**	**-4.86**	**4.72**	**-1.60**
Transformation	**34.49**	**34.06**	**26.49**	**28.43**	**29.85**	**37.09**
Electricity Generation	13.22	11.99	4.84	5.68	10.08	17.70
Bituminous	0.00	0.00	0.00	0.00	0.00	0.00
Sub-bituminous	13.22	11.99	4.84	5.68	10.08	17.70
Lignite	0.00	0.00	0.00	0.00	0.00	0.00
Cogeneration	7.75	7.95	7.39	7.91	7.56	8.42
Bituminous	0.00	0.00	0.00	0.00	0.00	0.00
Sub-bituminous	7.51	7.74	7.23	7.66	7.28	8.14
Lignite	0.24	0.21	0.16	0.26	0.28	0.27
Other Transformation	11.81	11.84	11.70	11.76	11.41	10.26
Production Losses and Own Use	1.72	2.28	2.55	3.07	0.80	0.71
Consumption (Observed)	**24.95**	**25.96**	**23.18**	**23.90**	**24.47**	**24.95**
Agriculture/ Forestry/ Fishing	1.59	2.08	1.17	2.71	1.98	2.05
Industrial	22.00	22.48	20.58	19.91	21.45	21.86
Commercial	1.00	0.99	1.08	1.00	0.75	0.81
Residential	0.35	0.39	0.34	0.30	0.29	0.24
Transport	0.01	0.01	0.00	0.00	0.00	0.00
Consumption (Calculated)	26.85	25.79	23.98	22.56	20.77	20.58
Statistical Difference	- 1.90	0.18	- 0.80	1.35	3.70	4.37

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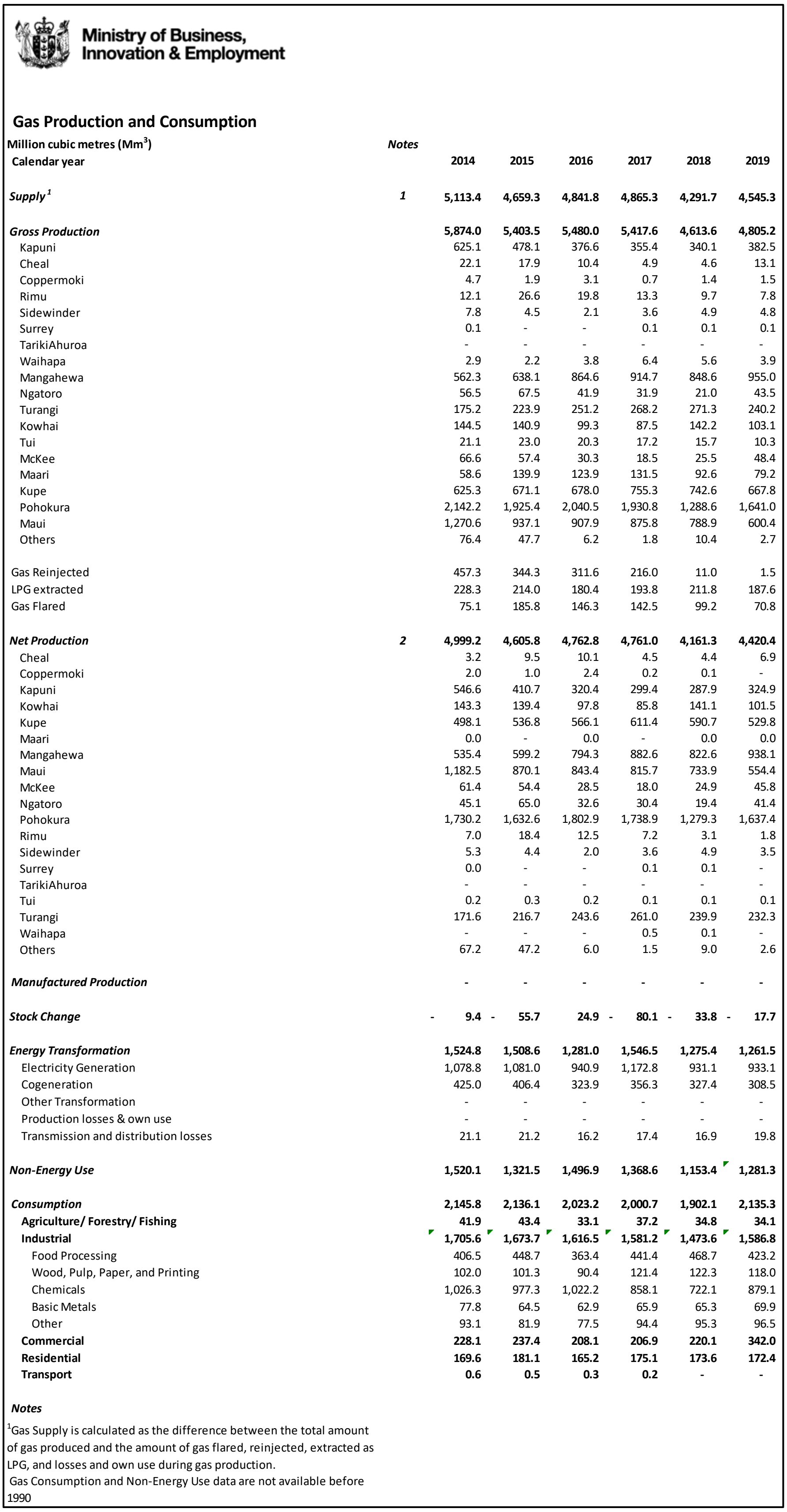
Notes:
1 Imports are bituminous and sub-bituminous coal.
2 Majority of coal exports are bituminous rank.
3 Stock change figures include coal at Huntly power station, NZ Steel and coal production sites.
4 Includes electricity generation, cogeneration, and losses and own use.

Appendix E: MBIE Data Tables for Gas

Source: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/gas-statistics/



Ministry of Business, Innovation & Employment

Gas Production and Consumption

Million cubic metres (Mm^3) **Calendar year**	***Notes***	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Supply[1]	*1*	**5,113.4**	**4,659.3**	**4,841.8**	**4,865.3**	**4,291.7**	**4,545.3**
Gross Production		**5,874.0**	**5,403.5**	**5,480.0**	**5,417.6**	**4,613.6**	**4,805.2**
Kapuni		625.1	478.1	376.6	355.4	340.1	382.5
Cheal		22.1	17.9	10.4	4.9	4.6	13.1
Coppermoki		4.7	1.9	3.1	0.7	1.4	1.5
Rimu		12.1	26.6	19.8	13.3	9.7	7.8
Sidewinder		7.8	4.5	2.1	3.6	4.9	4.8
Surrey		0.1	-	-	0.1	0.1	0.1
TarikiAhuroa		-	-	-	-	-	-
Waihapa		2.9	2.2	3.8	6.4	5.6	3.9
Mangahewa		562.3	638.1	864.6	914.7	848.6	955.0
Ngatoro		56.5	67.5	41.9	31.9	21.0	43.5
Turangi		175.2	223.9	251.2	268.2	271.3	240.2
Kowhai		144.5	140.9	99.3	87.5	142.2	103.1
Tui		21.1	23.0	20.3	17.2	15.7	10.3
McKee		66.6	57.4	30.3	18.5	25.5	48.4
Maari		58.6	139.9	123.9	131.5	92.6	79.2
Kupe		625.3	671.1	678.0	755.3	742.6	667.8
Pohokura		2,142.2	1,925.4	2,040.5	1,930.8	1,288.6	1,641.0
Maui		1,270.6	937.1	907.9	875.8	788.9	600.4
Others		76.4	47.7	6.2	1.8	10.4	2.7
Gas Reinjected		457.3	344.3	311.6	216.0	11.0	1.5
LPG extracted		228.3	214.0	180.4	193.8	211.8	187.6
Gas Flared		75.1	185.8	146.3	142.5	99.2	70.8
Net Production	*2*	**4,999.2**	**4,605.8**	**4,762.8**	**4,761.0**	**4,161.3**	**4,420.4**
Cheal		3.2	9.5	10.1	4.5	4.4	6.9
Coppermoki		2.0	1.0	2.4	0.2	0.1	-
Kapuni		546.6	410.7	320.4	299.4	287.9	324.9
Kowhai		143.3	139.4	97.8	85.8	141.1	101.5
Kupe		498.1	536.8	566.1	611.4	590.7	529.8
Maari		0.0	-	0.0	-	0.0	0.0
Mangahewa		535.4	599.2	794.3	882.6	822.6	938.1
Maui		1,182.5	870.1	843.4	815.7	733.9	554.4
McKee		61.4	54.4	28.5	18.0	24.9	45.8
Ngatoro		45.1	65.0	32.6	30.4	19.4	41.4
Pohokura		1,730.2	1,632.6	1,802.9	1,738.9	1,279.3	1,637.4
Rimu		7.0	18.4	12.5	7.2	3.1	1.8
Sidewinder		5.3	4.4	2.0	3.6	4.9	3.5
Surrey		0.0	-	-	0.1	0.1	-
TarikiAhuroa		-	-	-	-	-	-
Tui		0.2	0.3	0.2	0.1	0.1	0.1
Turangi		171.6	216.7	243.6	261.0	239.9	232.3
Waihapa		-	-	-	0.5	0.1	-
Others		67.2	47.2	6.0	1.5	9.0	2.6
Manufactured Production		**-**	**-**	**-**	**-**	**-**	**-**
Stock Change		**- 9.4**	**- 55.7**	**24.9**	**- 80.1**	**- 33.8**	**- 17.7**
Energy Transformation		**1,524.8**	**1,508.6**	**1,281.0**	**1,546.5**	**1,275.4**	**1,261.5**
Electricity Generation		1,078.8	1,081.0	940.9	1,172.8	931.1	933.1
Cogeneration		425.0	406.4	323.9	356.3	327.4	308.5
Other Transformation		-	-	-	-	-	-
Production losses & own use		-	-	-	-	-	-
Transmission and distribution losses		21.1	21.2	16.2	17.4	16.9	19.8
Non-Energy Use		**1,520.1**	**1,321.5**	**1,496.9**	**1,368.6**	**1,153.4**	**1,281.3**
Consumption		**2,145.8**	**2,136.1**	**2,023.2**	**2,000.7**	**1,902.1**	**2,135.3**
Agriculture/ Forestry/ Fishing		**41.9**	**43.4**	**33.1**	**37.2**	**34.8**	**34.1**
Industrial		**1,705.6**	**1,673.7**	**1,616.5**	**1,581.2**	**1,473.6**	**1,586.8**
Food Processing		406.5	448.7	363.4	441.4	468.7	423.2
Wood, Pulp, Paper, and Printing		102.0	101.3	90.4	121.4	122.3	118.0
Chemicals		1,026.3	977.3	1,022.2	858.1	722.1	879.1
Basic Metals		77.8	64.5	62.9	65.9	65.3	69.9
Other		93.1	81.9	77.5	94.4	95.3	96.5
Commercial		**228.1**	**237.4**	**208.1**	**206.9**	**220.1**	**342.0**
Residential		**169.6**	**181.1**	**165.2**	**175.1**	**173.6**	**172.4**
Transport		**0.6**	**0.5**	**0.3**	**0.2**	**-**	**-**

Notes

[1] Gas Supply is calculated as the difference between the total amount of gas produced and the amount of gas flared, reinjected, extracted as LPG, and losses and own use during gas production.

Gas Consumption and Non-Energy Use data are not available before 1990

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Gas Production and Consumption

Gross petajoules (PJ)	*Notes*						
Calendar year		**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Supply	*1*	**197.56**	**182.56**	**190.51**	**188.77**	**167.38**	**177.78**
Gross Production		**233.76**	**216.87**	**220.68**	**216.19**	**187.11**	**194.62**
Kapuni		16.47	12.50	9.86	9.23	10.36	9.86
Cheal		1.06	0.84	0.42	0.20	0.19	0.55
Coppermoki		0.24	0.09	0.15	0.03	0.07	0.08
Rimu		0.51	1.11	0.85	0.58	0.43	0.35
Sidewinder		0.31	0.18	0.08	0.14	0.19	0.18
Surrey		0.01	-	-	0.00	0.01	0.00
TarikiAhuroa		-	-	-	-	-	-
Waihapa		0.12	0.09	0.15	0.25	0.21	0.14
Mangahewa		22.28	25.18	33.65	35.44	32.80	37.30
Ngatoro		1.78	2.08	1.37	1.07	0.72	1.49
Turangi		7.05	9.00	10.29	10.91	11.04	9.75
Kowhai		5.79	5.64	3.99	3.48	5.56	4.02
Tui		1.01	1.10	0.97	0.82	0.75	0.49
McKee		2.66	2.27	1.18	0.72	0.99	3.69
Maari		2.94	7.48	6.20	6.47	4.79	4.40
Kupe		28.61	30.27	30.17	31.32	33.68	30.32
Pohokura		88.45	79.48	84.38	79.92	53.10	67.77
Maui		51.52	37.76	36.73	35.52	31.81	24.10
Others		2.97	1.81	0.24	0.07	0.40	0.11
Gas Reinjected		17.80	13.07	12.11	8.42	0.43	0.06
LPG extracted	*2*	8.89	8.13	7.01	7.55	8.27	7.44
Gas Flared		2.92	7.06	5.68	5.55	3.87	2.81
Net Production	*3*	**197.71**	**182.73**	**190.63**	**188.88**	**167.47**	**177.86**
Cheal		0.15	0.44	0.40	0.19	0.18	0.29
Coppermoki		0.10	0.05	0.12	0.01	0.00	-
Kapuni		14.40	10.74	8.39	7.78	8.77	8.37
Kowhai		5.74	5.58	3.93	3.42	5.52	3.96
Kupe		22.79	24.21	25.19	25.35	26.80	24.06
Maari		0.00	-	0.00	-	0.00	0.00
Mangahewa		21.21	23.64	30.91	34.20	31.80	36.64
Maui		47.95	35.06	34.12	33.08	29.60	22.26
McKee		2.46	2.15	1.11	0.70	0.96	3.50
Ngatoro		1.42	2.00	1.07	1.02	0.67	1.42
Pohokura		71.44	67.39	74.55	71.97	52.72	67.62
Rimu		0.30	0.77	0.54	0.32	0.14	0.08
Sidewinder		0.21	0.17	0.08	0.14	0.19	0.14
Surrey		0.00	-	-	0.00	0.00	-
TarikiAhuroa		-	-	-	-	-	-
Tui		0.01	0.01	0.01	0.01	0.01	0.00
Turangi		6.91	8.71	9.98	10.61	9.76	9.43
Waihapa		-	-	-	0.02	0.00	-
Others		2.61	1.79	0.23	0.06	0.35	0.10
Manufactured Production		-	-	-	-	-	-
		23.67	**25.79**	**32.03**	**34.90**	**32.76**	**40.14**
Stock Change		**- 0.37**	**- 2.12**	**0.97**	**- 3.12**	**- 1.32**	**- 0.70**
Energy Transformation		**65.95**	**63.34**	**55.14**	**66.15**	**56.98**	**56.55**
Electricity Generation		42.00	41.04	36.55	45.69	36.38	36.99
Cogeneration		16.54	15.43	12.58	13.88	12.79	12.23
Other Transformation		-	-	-	-	-	-
Production losses and own use		6.59	6.06	5.38	5.90	7.15	6.54
Transmission and distribution losses		0.82	0.80	0.63	0.68	0.66	0.79
Non-Energy Use		**59.18**	**50.18**	**58.15**	**53.32**	**45.06**	**50.79**
Consumption		**83.54**	**81.11**	**78.60**	**77.95**	**74.31**	**84.64**
Agriculture/ Forestry/ Fishing		**1.63**	**1.65**	**1.28**	**1.45**	**1.36**	**1.35**
Industrial		**66.40**	**63.55**	**62.80**	**61.60**	**57.57**	**62.90**
Food Processing		15.83	17.04	14.12	17.20	18.31	16.78
Wood, Pulp, Paper, and Printing		3.97	3.85	3.51	4.73	4.78	4.68
Chemicals		39.95	37.11	39.71	33.43	28.21	34.85
Basic Metals		3.03	2.45	2.44	2.57	2.55	2.77
Other		3.62	3.11	3.01	3.68	3.72	3.83
Commercial		**8.88**	**9.01**	**8.09**	**8.06**	**8.60**	**13.56**
Residential		**6.60**	**6.88**	**6.42**	**6.82**	**6.78**	**6.83**
Transport		**0.02**	**0.02**	**0.01**	**0.01**	**-**	**-**

Notes

[1] Gas Supply is calculated as the difference between the total amount of gas produced and the amount of gas flared, reinjected, extracted as LPG, and losses and own use during gas production.

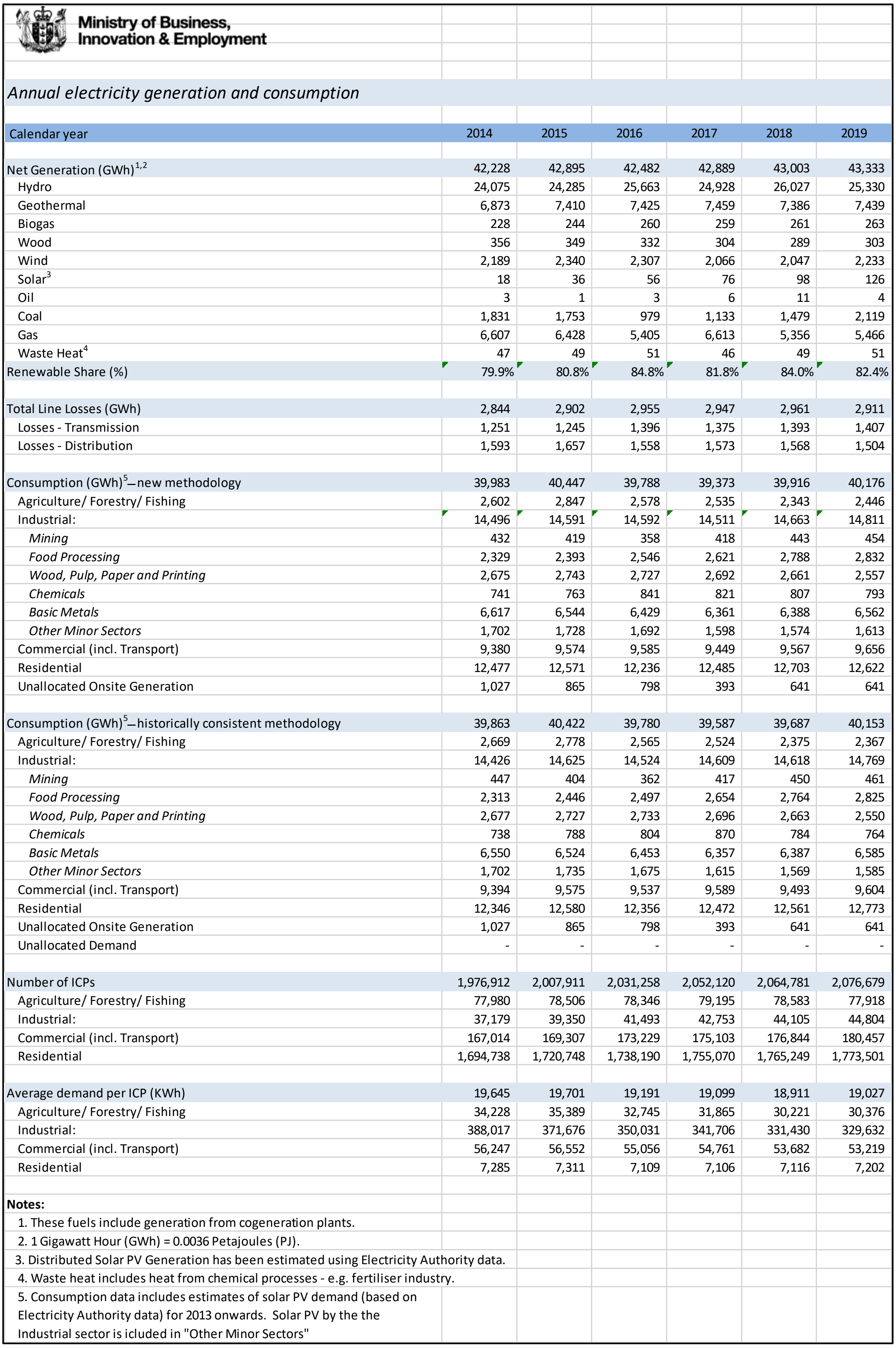
[2] Includes the Natural Gas Liquids condensed from Kapuni

[3] Net Gas Production is calculated as the difference between the total amount of gas produced and the amount of gas flared, reinjected, extracted as LPG, and losses and own use during gas production.

Gas Consumption and Non-Energy Use data are not available before 1990

Appendix F: MBIE Electricity Data Tables

Source: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/electricity-statistics/



Ministry of Business, Innovation & Employment

Annual electricity generation and consumption

Calendar year	2014	2015	2016	2017	2018	2019
Net Generation (GWh)[1,2]	42,228	42,895	42,482	42,889	43,003	43,333
Hydro	24,075	24,285	25,663	24,928	26,027	25,330
Geothermal	6,873	7,410	7,425	7,459	7,386	7,439
Biogas	228	244	260	259	261	263
Wood	356	349	332	304	289	303
Wind	2,189	2,340	2,307	2,066	2,047	2,233
Solar[3]	18	36	56	76	98	126
Oil	3	1	3	6	11	4
Coal	1,831	1,753	979	1,133	1,479	2,119
Gas	6,607	6,428	5,405	6,613	5,356	5,466
Waste Heat[4]	47	49	51	46	49	51
Renewable Share (%)	79.9%	80.8%	84.8%	81.8%	84.0%	82.4%
Total Line Losses (GWh)	2,844	2,902	2,955	2,947	2,961	2,911
Losses - Transmission	1,251	1,245	1,396	1,375	1,393	1,407
Losses - Distribution	1,593	1,657	1,558	1,573	1,568	1,504
Consumption (GWh)[5]—new methodology	39,983	40,447	39,788	39,373	39,916	40,176
Agriculture/ Forestry/ Fishing	2,602	2,847	2,578	2,535	2,343	2,446
Industrial:	14,496	14,591	14,592	14,511	14,663	14,811
Mining	432	419	358	418	443	454
Food Processing	2,329	2,393	2,546	2,621	2,788	2,832
Wood, Pulp, Paper and Printing	2,675	2,743	2,727	2,692	2,661	2,557
Chemicals	741	763	841	821	807	793
Basic Metals	6,617	6,544	6,429	6,361	6,388	6,562
Other Minor Sectors	1,702	1,728	1,692	1,598	1,574	1,613
Commercial (incl. Transport)	9,380	9,574	9,585	9,449	9,567	9,656
Residential	12,477	12,571	12,236	12,485	12,703	12,622
Unallocated Onsite Generation	1,027	865	798	393	641	641
Consumption (GWh)[5]—historically consistent methodology	39,863	40,422	39,780	39,587	39,687	40,153
Agriculture/ Forestry/ Fishing	2,669	2,778	2,565	2,524	2,375	2,367
Industrial:	14,426	14,625	14,524	14,609	14,618	14,769
Mining	447	404	362	417	450	461
Food Processing	2,313	2,446	2,497	2,654	2,764	2,825
Wood, Pulp, Paper and Printing	2,677	2,727	2,733	2,696	2,663	2,550
Chemicals	738	788	804	870	784	764
Basic Metals	6,550	6,524	6,453	6,357	6,387	6,585
Other Minor Sectors	1,702	1,735	1,675	1,615	1,569	1,585
Commercial (incl. Transport)	9,394	9,575	9,537	9,589	9,493	9,604
Residential	12,346	12,580	12,356	12,472	12,561	12,773
Unallocated Onsite Generation	1,027	865	798	393	641	641
Unallocated Demand	-	-	-	-	-	-
Number of ICPs	1,976,912	2,007,911	2,031,258	2,052,120	2,064,781	2,076,679
Agriculture/ Forestry/ Fishing	77,980	78,506	78,346	79,195	78,583	77,918
Industrial:	37,179	39,350	41,493	42,753	44,105	44,804
Commercial (incl. Transport)	167,014	169,307	173,229	175,103	176,844	180,457
Residential	1,694,738	1,720,748	1,738,190	1,755,070	1,765,249	1,773,501
Average demand per ICP (KWh)	19,645	19,701	19,191	19,099	18,911	19,027
Agriculture/ Forestry/ Fishing	34,228	35,389	32,745	31,865	30,221	30,376
Industrial:	388,017	371,676	350,031	341,706	331,430	329,632
Commercial (incl. Transport)	56,247	56,552	55,056	54,761	53,682	53,219
Residential	7,285	7,311	7,109	7,106	7,116	7,202

Notes:

1. These fuels include generation from cogeneration plants.
2. 1 Gigawatt Hour (GWh) = 0.0036 Petajoules (PJ).
3. Distributed Solar PV Generation has been estimated using Electricity Authority data.
4. Waste heat includes heat from chemical processes - e.g. fertiliser industry.
5. Consumption data includes estimates of solar PV demand (based on Electricity Authority data) for 2013 onwards. Solar PV by the the Industrial sector is icluded in "Other Minor Sectors"

Table 6: Net Electricity Generation by Fuel Type - Cogeneration Separated (GWh)

Calendar Year	Electricity Only Plants									Cogeneration[2]	Total
	Hydro	Geo-thermal	Biogas	Wind	Solar PV	Oil[1]	Coal	Gas	**Sub- total**		
2014	24,075	6,806	165	2,189	18	3	1,228	5,327	**39,792**	**2,417**	**42,209**
2015	24,285	7,343	176	2,340	36	1	1,134	5,192	**40,471**	**2,388**	**42,859**
2016	25,663	7,358	181	2,307	56	3	404	4,512	**40,429**	**1,997**	**42,426**
2017	24,928	7,392	191	2,066	76	5	517	5,603	**40,701**	**2,113**	**42,813**
2018	26,027	7,319	196	2,047	98	11	891	4,450	**40,939**	**1,965**	**42,904**
Δ2013/2018 p.a.	2.7%	4.0%	6.7%	0.5%	70.4%	25.7%	-11.3%	-8.2%	**0.8%**	-4.3%	0.5%
Δ2017/2018	4.4%	-1.0%	2.7%	-0.9%	30.2%	102.4%	72.3%	-20.6%	**0.6%**	-7.0%	0.2%

Notes

1) Negative generation by oil-fired plants implies a net import into the station to maintain station viability and system voltage stability.

2) Individual estimates of generation from cogeneration plant types can be obtained by subtracting the electricity-only plant information table 2

P = Provisional figures. Electricity information is collected from a number of sources including, Statistics New Zealand, the Electricity Authority, and generators. Some generator supplied information is collected only on a March year basis so figures for the most recent year in the ENZ will always be provisional estimates.

Table 5: Electricity Supply and Demand Energy Balance (GWh)

		2014	2015	2016	2017	2018
SUPPLY	**Total Gross Generation**	**43,538**	**44,224**	**43,700**	**44,192**	**44,249**
	Own Use ~ Parasitic Load[1]	-1,310	-1,329	-1,218	-1,304	-1,246
	Total Net Generation	**42,228**	**42,895**	**42,482**	**42,889**	**43,003**
	Electricity Only Plant	39,792	40,471	40,429	40,701	40,939
	Combined Heat and Power Plant	2,417	2,388	1,997	2,113	1,965
	Small Scale Distributed Generation[2]	18	36	56	76	98
	Total Lines Losses[3]	**-3,003**	**-2,895**	**-2,844**	**-2,902**	**-2,955**
	Losses ~ Transmission	-1,387	-1,305	-1,251	-1,245	-1,396
	Losses ~ Distribution	-1,616	-1,590	-1,593	-1,657	-1,558
Total Electricity Demand (Calculated)		**39,225**	**40,000**	**39,638**	**39,987**	**40,048**
Statistical Difference[4]		-1.6%	-1.1%	-0.4%	1.0%	0.9%
DEMAND	**Total Electricity Demand (Observed)[5]**	**39,863**	**40,422**	**39,780**	**39,587**	**39,687**
	Agricuture Forestry and Fishing	2,669	2,778	2,565	2,524	2,375
	Industrial	14,426	14,625	14,524	14,609	14,618
	Commercial (including Transport)[6]	9,394	9,575	9,537	9,589	9,493
	Residential	12,346	12,580	12,356	12,472	12,561
	Calculated Onsite Consumption[7]	1,027	865	798	393	641
Electricity entering system[8]		41,182	41,995	41,628	42,420	42,388
National loss ratio[9]		7.3%	6.9%	6.8%	6.8%	7.0%

Notes

1) Electricity used by the generator for auxilliary services (e.g. lighting, coal grinders) and internal losses

2) Currently only accounts for distributed Solar PV generation as obtained from the Electricity Authority.

3) Loss information is obtained through electricity disclosures by Transpower and the distribution companies.

4) Statistical differences exist between supply and demand figures as the information comes from different sources

5) Demand numbers in this table are based on data calculated with a historically consistent methodology. For more information see **Table 2**.

6) Transport is included with commercial as the MBIE does not have a reliable time series of electricity used for transport (electric trains and trolley busses and so on). For the balance tables presented at the front of the Energy Data File, approximately 0.36 PJ or 100 GWh has been used for all years (subtracted from commercial demand) until which time MBIE can provide improved estimates. Sales to different parts of the commercial transport sector does not provide an accurate enough reflection of demand for transport as it includes some electricity used for airports, train stations and bus terminals etc, which should be excluded from the transport sector under IEA definitions.

7) Calculated estimate based on the difference between net production and electricity entering the system. This includes on-site generation not exported into the network. Note in 2011 and 2012 an improved estimate has been made from a mix of data sources (net generation, Electricity Authority GXP generation, and annual onsite generation). In the balance tables in section B, this figure is added to the Industrial Unallocated sector.

8) Total amount of electricity entering the local and national transmission and distribution networks. Includes embedded generation.

Appendix G: Geothermal Air Emissions – Waikato Regional Council Monitoring Reports

Source: Mercury (2018, 2019a, 2019b)

Field	Parameter	Unit	2013	2014	2015	2016	2017	2018	Average/ Indicative	Typical Annual Emission (kg)
Mokai	Annual Generation	Gwh	-	-		-	772	782	777	
	H_2S	kg/hr	131	100-200					150	1,314,000
	Hg	g/hr	4.45	2.68	2-10				5	43.8
	Isopentane	t/year	18	18	-	17.8	15.1	25.5	19.1	19,110
Rotokawa	Annual Generation	Gwh	-	277	251	278	271	270	269	
	H_2S	kg/hr	50-150						125	1,095,000
	Hg	g/hr	<5-65						5	43.8
Nga Awa Purua	Annual Generation	Gwh	-	1,042	1,083	1,111	1,157	1,133	1,105	
	H_2S	kg/hr	100-650						500	4,380,000
	Hg	g/hr	10-35						25	219.0
Ngatamariki	Annual Generation	Gwh	-	629	733	699	723	700	697	
	H_2S	kg/hr	-	125	133-183	108-188	100-200	100-200	150	1,314,000
	Hg	g/hr	-	13.9 (Jan) 6.7 (Sept)	<10	<18	<18	<10	7.5	65.7
	N-pentane	t/year	-	25	47	51	7	11	28.2	28,200

Appendix H: Numerical Operational Impact Results per kWh by Generation Technology

		Gas	**Coal**	**Geothermal**	**Hydro**	**Wind**	**Biomass**	**Utility Solar**	**Distributed Solar**
GWP$_{100}$ **(**kg CO$_{2eq}$/kWh**)**	O&M	0.478	1.03	0.107	0.005	7.34×10^{-5}	0.265	0.014	7.31×10^{-6}
	T&D	0.039	0.083	0.009	0.0004	5.92×10^{-6}	0.021	0.001	-
GWP$_{100}$ excl biogenic **(**kg CO$_{2eq}$/kWh**)**	O&M	0.478	1.03	0.107	0.005	7.36×10^{-5}	0.045	0.014	6.23×10^{-6}
	T&D	0.039	0.083	0.009	0.0004	5.94×10^{-6}	0.004	0.001	-
GTP$_{100}$ **(**kg CO$_{2eq}$/kWh**)**	O&M	0.462	1.01	0.0878	0.001	7.00×10^{-5}	0.261	0.013	6.88×10^{-6}
	T&D	3.73×10^{-2}	8.15×10^{-2}	7.09×10^{-3}	9.02×10^{-5}	5.66×10^{-6}	2.11×10^{-2}	1.05×10^{-3}	-
ADP elements (kg Sb$_{eq}$/kWh)	O&M	9.84×10^{-9}	4.53×10^{-8}	3.59×10^{-10}	8.29×10^{-11}	3.69×10^{-10}	7.07×10^{-8}	3.27×10^{-9}	2.35×10^{-11}
	T&D	7.94×10^{-10}	3.66×10^{-9}	2.89×10^{-11}	6.69×10^{-12}	2.98×10^{-11}	5.71×10^{-9}	2.65×10^{-10}	-
ADP Fossil (MJ/kWh)	O&M	7	17.4	2.98×10^{-4}	4.67×10^{-4}	0.002	0.487	0.228	8.02×10^{-5}
	T&D	0.566	1.406	2.40×10^{-5}	3.78×10^{-5}	1.68×10^{-4}	0.039	0.018	-
EP (kg Phosphate$_{eq}$/kWh)	O&M	1.89×10^{-4}	5.0×10^{-3}	2.88E-05	2.66×10^{-8}	1.18×10^{-7}	6.0×10^{-4}	3.11×10^{-6}	8.77×10^{-8}
	T&D	1.53×10^{-5}	4.04×10^{-4}	4.66E-06	2.14×10^{-9}	9.54×10^{-9}	4.84×10^{-5}	2.51×10^{-7}	-
AP **(**kg SO$_{2eq}$/kWh)	O&M	7.16×10^{-4}	7.60×10^{-3}	0.00449	6.62×10^{-8}	2.95×10^{-7}	1.63×10^{-3}	1.82×10^{-5}	3.77×10^{-8}
	T&D	5.78×10^{-5}	6.13×10^{-4}	0.000724	5.35×10^{-9}	2.38×10^{-8}	1.31×10^{-4}	1.47×10^{-6}	-
ODP (kg CFC$_{eq}$/kWh)	O&M	1.19×10^{-9}	4.87×10^{-9}	1.02×10^{-11}	4.64×10^{-12}	2.07×10^{-11}	5.98×10^{-9}	1.28×10^{-9}	1.0×10^{-12}
	T&D	9.58×10^{-11}	3.93×10^{-10}	8.27×10^{-13}	3.75×10^{-13}	1.67×10^{-12}	4.83×10^{-10}	1.03×10^{-10}	-
POCP (kg Ethene$_{eq}$/kWh)	O&M	7.89×10^{-5}	3.67×10^{-4}	1.19×10^{-5}	1.13×10^{-6}	1.30×10^{-7}	3.75×10^{-4}	2.84×10^{-6}	2.73×10^{-9}
	T&D	6.37×10^{-6}	2.96×10^{-5}	9.61×10^{-7}	9.12×10^{-8}	1.05×10^{-8}	3.03×10^{-5}	2.30×10^{-7}	-
PED renewable (MJ/kWh)	O&M	0.006	0.088	2.86×10^{-5}	3.63	3.7	17.2	6.46×10^{-4}	3.85
	T&D	5.17×10^{-4}	0.007	2.314×10^{-6}	0.293	0.299	1.388	5.21×10^{-5}	-
PED non-renewable (MJ/ kWh)	O&M	7	17.4	3.43×10^{-4}	4.78×10^{-4}	0.002	0.522	0.23	8.83×10^{-5}
	T&D	0.566	1.407	2.77×10^{-5}	3.86×10^{-5}	1.715×10^{-4}	0.042	0.018	
PED total (MJ/kWh)	O&M	7.01	17.5	3.71×10^{-4}	3.63	3.71	17.7	0.23	3.85
	T&D	0.566	1.414	3.0×10^{-5}	0.293	0.299	1.43	0.019	-

Appendix I: Numerical Infrastructure Impact Results per MW of New Capacity by Generation Technology

	Gas	Geothermal	Hydropower	Wind	Utility Solar	Distributed Solar	Distributed Solar with Battery
GWP_{100} (kg CO_{2eq}/MW)	6.71×10^4	7.76×10^5	4.71×10^5	9.07×10^5	2.87×10^6	2.31×10^6	2.32×10^6
GWP_{100} excl biogenic (kg CO_{2eq}/MW)	6.70×10^4	7.78×10^5	4.72×10^5	9.11×10^5	2.89×10^6	2.31×10^6	2.32×10^6
GTP_{100} (kg CO_{2eq}/MW)	6.48×10^4	7.33×10^5	4.64×10^5	8.54×10^5	2.66×10^6	2.17×10^6	2.18×10^6
ADP elements (kg Sb_{eq}/MW)	1.46	4.41	1.86	46.5	32.8	86.7	87.4
ADP Fossil (MJ/MW)	8.54×10^5	9.84×10^6	3.25×10^6	1.19×10^7	3.35×10^7	3.15×10^7	3.16×10^7
EP (kg $Phosphate_{eq}$/MW)	2.78×10^4	1,377	761	6,580	1.13×10^4	9,260	9,335
AP (kg SO_{2eq}/MW)	762	4,403	1,810	9,330	2.90×10^4	1.52×10^4	1.53×10^4
ODP (kg CFC_{eq}/MW)	0.003	0.069	0.015	0.064	0.179	0.222	0.223
POCP (kg $Ethene_{eq}$/MW)	44.7	607	143	788	2,360	1,280	1,286
PED renewable (MJ/MW)	4.26×10^4	4.80×10^5	9.72×10^4	7.74×10^5	2.32×10^6	4.92×10^6	4.93×10^6
PED non-renewable (MJ/MW)	8.77×10^5	1.01×10^7	3.35×10^6	1.28×10^7	3.53×10^7	3.50×10^7	3.51×10^7
PED total (MJ/MW)	9.19×10^5	1.06×10^7	3.44×10^6	1.36×10^7	3.76×10^7	4.00×10^7	4.01×10^7

Appendix J: Total Cumulative Results (2018-2050 & 2019-2035) and Total Annual Results (2019, 2035 & 2050) by Indicator and Scenario

Indicator	Scenario	Total Cumulative Impact 2018-2050	Total Cumulative Impact 2019-2035	Total Annual Impact - 2019	Total Annual Impact - 2035	Total Annual Impact - 2050
GWP_{100}	MBIE Reference	1.85E+11	1.10E+11	7.47E+09	5.54E+09	4.69E+09
	MBIE Growth	1.98E+11	1.13E+11	7.61E+09	5.58E+09	5.26E+09
	MBIE Global	1.70E+11	1.04E+11	7.43E+09	5.02E+09	3.80E+09
	MBIE Environmental	2.01E+11	1.14E+11	7.47E+09	5.66E+09	4.93E+09
	MBIE Disruptive	2.12E+11	1.17E+11	7.52E+09	6.77E+09	5.80E+09
	ICCC BAU	-	7.93E+10	5.96E+09	3.91E+09	-
	ICCC 100% Renewable	-	7.32E+10	6.14E+09	2.17E+09	-
	ICCC Acc Electrification	-	9.39E+10	6.09E+09	4.69E+09	-
GWP_{100} excl biogenic	MBIE Reference	1.81E+11	1.08E+11	7.33E+09	5.41E+09	4.56E+09
	MBIE Growth	1.94E+11	1.11E+11	7.48E+09	5.44E+09	5.12E+09
	MBIE Global	1.66E+11	1.02E+11	7.29E+09	4.88E+09	3.67E+09
	MBIE Environmental	1.97E+11	1.12E+11	7.34E+09	5.53E+09	4.79E+09
	MBIE Disruptive	2.06E+11	1.15E+11	7.39E+09	6.61E+09	5.61E+09
	ICCC BAU	-	7.81E+10	5.90E+09	3.84E+09	-
	ICCC 100% Renewable	-	7.14E+10	6.07E+09	2.03E+09	-
	ICCC Acc Electrification	-	9.27E+10	6.02E+09	4.62E+09	-
GTP_{100} (IPCC)	MBIE Reference	1.69E+11	1.02E+11	7.01E+09	5.02E+09	4.17E+09
	MBIE Growth	1.81E+11	1.04E+11	7.15E+09	5.05E+09	4.66E+09
	MBIE Global	1.56E+11	9.64E+10	6.98E+09	4.55E+09	3.38E+09
	MBIE Environmental	1.84E+11	1.05E+11	7.02E+09	5.14E+09	4.34E+09
	MBIE Disruptive	1.93E+11	1.09E+11	7.07E+09	6.16E+09	5.15E+09
	ICCC BAU	-	7.21E+10	5.54E+09	3.48E+09	-
	ICCC 100% Renewable	-	6.59E+10	5.70E+09	1.76E+09	-
	ICCC Acc Electrification	-	8.60E+10	5.66E+09	4.21E+09	-
ADP Elements	MBIE Reference	1,019,233	466,526	28,326	38,280	35,770
	MBIE Growth	1,134,721	515,851	28,330	42,557	41,269
	MBIE Global	786,934	382,902	27,125	30,225	24,814
	MBIE Environmental	1,320,547	580,020	28,326	44,250	35,587
	MBIE Disruptive	1,334,765	599,442	28,327	56,750	35,639
	ICCC BAU	-	484,925	26,449	484,925	-
	ICCC 100% Renewable	-	556,565	31,850	23,983	-
	ICCC Acc Electrification	-	545,066	31,149	24,023	-
ADP Fossil	MBIE Reference	1.99E+12	1.28E+12	9.65E+10	5.50E+10	4.14E+10
	MBIE Growth	2.10E+12	1.31E+12	9.88E+10	5.58E+10	4.47E+10
	MBIE Global	1.89E+12	1.25E+12	9.60E+10	5.18E+10	3.49E+10
	MBIE Environmental	2.13E+12	1.33E+12	9.66E+10	5.78E+10	4.02E+10
	MBIE Disruptive	2.25E+12	1.38E+12	9.73E+10	6.99E+10	4.81E+10
	ICCC BAU	-	8.34E+11	7.33E+10	3.47E+10	-
	ICCC 100% Renewable	-	7.08E+11	7.55E+10	3.85E+09	-
	ICCC Acc Electrification	-	1.03E+12	7.48E+10	4.36E+10	-
Eutrophication Potential	MBIE Reference	4.39E+08	2.53E+08	1.75E+07	1.25E+07	1.11E+07
	MBIE Growth	4.63E+08	2.61E+08	1.78E+07	1.29E+07	1.19E+07
	MBIE Global	4.07E+08	2.41E+08	1.73E+07	1.12E+07	9.82E+06
	MBIE Environmental	4.83E+08	2.67E+08	1.75E+07	1.28E+07	1.12E+07
	MBIE Disruptive	4.91E+08	2.74E+08	1.74E+07	1.63E+07	1.16E+07
	ICCC BAU	-	1.44E+08	1.15E+07	6.39E+06	-
	ICCC 100% Renewable	-	1.52E+08	1.25E+07	3.83E+06	-
	ICCC Acc Electrification	-	1.73E+08	1.23E+07	6.72E+06	-
Acidification Potential	MBIE Reference	2.65E+09	1.34E+09	6.86E+07	8.70E+07	8.78E+07
	MBIE Growth	2.88E+09	1.39E+09	6.91E+07	8.63E+07	1.02E+08
	MBIE Global	2.27E+09	1.18E+09	6.84E+07	7.32E+07	6.76E+07
	MBIE Environmental	2.93E+09	1.38E+09	6.61E+07	8.32E+07	1.00E+08
	MBIE Disruptive	3.00E+09	1.37E+09	6.86E+07	9.67E+07	1.13E+08
	ICCC BAU	-	1.08E+09	5.85E+07	6.80E+07	-
	ICCC 100% Renewable	-	1.15E+09	6.02E+07	7.24E+07	-
	ICCC Acc Electrification	-	1.17E+09	5.99E+07	7.59E+07	-
Ozone Depletion Potential	MBIE Reference	1629.33	749.90	48.26	55.49	61.62
	MBIE Growth	2017.41	835.23	48.84	58.92	77.65
	MBIE Global	1098.63	584.82	45.32	37.72	32.29
	MBIE Environmental	2480.31	990.71	48.26	76.88	62.91
	MBIE Disruptive	2573.50	1079.31	48.39	125.81	66.28
	ICCC BAU	-	645.65	41.21	27.50	-
	ICCC 100% Renewable	-	820.00	50.31	25.14	-
	ICCC Acc Electrification	-	833.32	48.41	30.41	-

Indicator	Scenario	Total Cumulative Impact 2018-2050	Total Cumulative Impact 2019-2035	Total Annual Impact - 2019	Total Annual Impact - 2035	Total Annual Impact - 2050
POCP	MBIE Reference	5.59E+07	3.20E+07	2.16E+06	1.71E+06	1.45E+06
	MBIE Growth	6.07E+07	3.32E+07	2.20E+06	1.74E+06	1.59E+06
	MBIE Global	5.06E+07	2.99E+07	2.14E+06	1.50E+06	1.21E+06
	MBIE Environmental	6.33E+07	3.40E+07	2.17E+06	1.76E+06	1.48E+06
	MBIE Disruptive	6.67E+07	3.57E+07	2.17E+06	2.49E+06	1.70E+06
	ICCC BAU	-	2.13E+07	1.59E+06	9.95E+05	-
	ICCC 100% Renewable	-	2.27E+07	1.72E+06	7.27E+05	-
	ICCC Acc Electrification	-	2.56E+07	1.70E+06	1.12E+06	-
PED Renewable	MBIE Reference	4.71421E+12	2.11997E+12	1.14342E+11	1.38138E+11	1.7675E+11
	MBIE Growth	5.04811E+12	2.21115E+12	1.14362E+11	1.54293E+11	1.9727E+11
	MBIE Global	4.40037E+12	2.097E+12	1.14276E+11	1.29346E+11	1.50733E+11
	MBIE Environmental	5.25283E+12	2.29753E+12	1.14342E+11	1.6747E+11	2.0504E+11
	MBIE Disruptive	5.39661E+12	2.36089E+12	1.14342E+11	1.681E+11	2.1255E+11
	ICCC BAU	-	2.08772E+12	1.10053E+11	1.36589E+11	-
	ICCC 100% Renewable	-	2.19416E+12	1.10169E+11	1.48181E+11	-
	ICCC Acc Electrification	-	2.25373E+12	1.10146E+11	1.54891E+11	-
PED Non-renewable	MBIE Reference	2.01E+12	1.29E+12	9.70E+10	5.57E+10	4.23E+10
	MBIE Growth	2.12E+12	1.32E+12	9.92E+10	5.66E+10	4.57E+10
	MBIE Global	1.90E+12	1.25E+12	9.64E+10	5.22E+10	3.53E+10
	MBIE Environmental	2.16E+12	1.34E+12	9.71E+10	5.88E+10	4.10E+10
	MBIE Disruptive	2.28E+12	1.39E+12	9.77E+10	7.13E+10	4.89E+10
	ICCC BAU	-	8.41E+11	7.37E+10	3.50E+10	-
	ICCC 100% Renewable	-	7.17E+11	7.59E+10	4.17E+09	-
	ICCC Acc Electrification	-	1.04E+12	7.54E+10	4.39E+10	-
PED Total	MBIE Reference	6.72413E+12	3.41046E+12	2.1144E+11	1.945E+11	2.1937E+11
	MBIE Growth	7.16898E+12	3.52633E+12	2.1355E+11	2.1125E+11	2.433E+11
	MBIE Global	6.30009E+12	3.35069E+12	2.1091E+11	1.8147E+11	1.8674E+11
	MBIE Environmental	7.41284E+12	3.63312E+12	2.1144E+11	2.268E+11	2.4666E+11
	MBIE Disruptive	7.68148E+12	3.75308E+12	2.1244E+11	2.39E+11	2.6184E+11
	ICCC BAU	-	2.92787E+12	1.834E+11	1.7129E+11	-
	ICCC 100% Renewable	-	2.90944E+12	1.8646E+11	1.5178E+11	-
	ICCC Acc Electrification	-	3.29885E+12	1.8508E+11	1.9924E+11	-

Appendix K: Life Cycle Stages Contributing to Impacts

Figure K1 to Figure K11 provide the annual break-down for each of the eight scenarios of the life-cycle stages and fuel type contributing to each environmental indicator except GWP_{100} which can be found in Figure 6.7. The following sections provide an overview of the main life-cycle stages contributing to each indicator and key differences between scenarios. The equivalent discussion for the climate change indicators (GWP_{100}, GWP_{100} excl biogenic, GTP_{100}) is contained in Section 6.3.3. The percentage ranges noted in the discussion below represent the percentage contribution to total impacts based on cumulative impacts over the study period (i.e. 2018-2050 for MBIE scenarios; 2019-2035 for ICCC scenarios).

Abiotic Depletion Potential

Abiotic depletion potential is considered in terms of depletion of elements (ADP elements) and fossil-based resources (ADP fossil).

The main contributors to the ADP elements indicator (Figure K3) are embodied impacts of infrastructure particularly distribution infrastructure (47-80%), distributed solar infrastructure (9-31%) and wind infrastructure (8-23%). Utility solar infrastructure is also an important contributor during some years for the MBIE Growth, Environmental and Disruptive scenarios but accounts for less than 3% over the full modelling period for all scenarios. Impacts vary from year to year for most scenarios depending on the amount and type of new generation infrastructure but increase significantly during the 2030s and 2040s for the Growth, Environmental and Disruptive scenarios due to significant increases in solar and wind generation construction. In contrast to distribution infrastructure, transmission infrastructure only accounts for 1-2% of total impacts. The combined impacts from O&M, T&D, and other infrastructure only account for 1% of total impacts.

The primary contributors to ADP fossil (Figure K4) are O&M impacts of coal and gas . Coal O&M comprises 36-44% of total impacts for the MBIE scenarios and 22-25% of total impacts for the ICCC scenarios. Gas O&M comprises 40-44% of total impacts for the MBIE scenarios and 53-62% of total impacts for the ICCC scenarios. T&D contribute 6-7% of total impacts.

Distributed solar infrastructure becomes more significant from the mid-2030s onwards for those MBIE scenarios that assume a significant increase in this generation technology and contributes 7% of total cumulative impacts over the modelling period for the Environmental and Disruptive scenarios. Other infrastructure categories contribute less than 5% of impacts per category.

There is a general decrease in impacts during the 2020s and 2030s as the proportion of fossil fuels in the generation mix decreases. The level of impacts during the 2040s remains relatively steady as generation demand continues to increase and the impact of increasing levels of distributed solar infrastructure become more significant in some scenarios.

Eutrophication Potential

The most important contributor to the EP indicator (Figure K5) is coal O&M which accounts for 52-59% of total impacts for MBIE scenarios and 34-39% of total impacts for ICCC scenarios. Impacts due to distribution infrastructure were the next largest contributor accounting for 16-20% of total impacts for MBIE scenarios and 24-29% of total impacts for ICCC scenarios. Gas O&M (5-10%), T&D (3-5%), distributed solar infrastructure (2-9%), and wind infrastructure (2-12%) are smaller but significant contributors to this indicator.

The total level of EP impacts is closely related to the level of coal generation. The MBIE scenarios all show a decrease in EP around 2030 which aligns with the assumed decommissioning of coal fired generation at Huntly. In the Growth, Environmental and Disruptive scenarios this decrease is partially offset by increases in infrastructure impacts during later years. The ICCC scenarios all show a decrease in EP impacts between 2019 and 2035 due to decreasing levels of generation from coal.

Acidification Potential

The biggest contributor to the AP indicator (Figure K6) is geothermal O&M which account for 66-73% of total impacts across all scenarios. The next most significant contributor is coal which accounts for 7-16% % of total impacts. Other important contributors are distribution infrastructure (4-5%) and T&D (6-7%). The total impacts for this indicator are relatively steady or increase during the study period as impacts due to geothermal O&M increase as impacts due to coal O&M decrease.

Ozone Depletion Potential

The most important contributor to the ODP indicator (Figure K7) for all scenarios except the MBIE Global scenario is infrastructure associated with new distributed solar generation (23-43%). Coal O&M is the most important contributor for the MBIE Global scenario (17%) and is also an important contributor for other scenarios (6-14%).

A number of other activities contribute to ODP including gas O&M (6-14%) and biomass O&M (3-9%), utility solar infrastructure (0-10%), wind infrastructure (8-22%), distribution infrastructure (6-14%), and geothermal infrastructure from geothermal plant and make-up wells (8-11%). The relative importance of these different activities varies depending on the scenario.

The overall change in impact over time for this indicator is strongly related to the construction of new solar and wind generation capacity for each of the scenarios. The total impacts in the MBIE Reference and Global and the three ICCC scenarios are relatively consistent throughout the time periods considered. In contrast, in the MBIE Growth, Environmental and Disruptive scenarios, the total impacts for this indicator increases significantly during the 2030s and 2040s but are quite variable depending on when new generation capacity is constructed.

Photochemical Ozone Creation Potential

The largest contributor to POCP (Figure K8) for the MBIE scenarios is coal O&M (26-34%) and gas O&M provides the next largest contribution (15-19%). The largest contributor for the ICCC scenarios is gas O&M (19-28%) followed by coal O&M (16-19%) representing the next largest contribution. This reflects the lower proportion of coal generation under the ICCC scenarios compared to the MBIE scenarios.

A number of other categories also contribute significantly to this indicator including geothermal O&M (8-10%), biomass O&M (7-13%), T&D (4-5%), as well as infrastructure associated with wind (2-10%), distributed solar (2-10%), utility solar (0-5%) and distribution (9-14%). The combination of both O&M and infrastructure impacts results in a general decrease in impacts over time for most scenarios but with peaks during years with large amounts of infrastructure construction particularly for the MBIE scenarios with larger amounts of new solar and wind generation (i.e. Growth, Environmental and Disruptive scenarios).

Primary Energy Demand

The biggest contributor to PED renewable (Figure K9) is hydropower O&M (61-75%) reflecting the predominance of hydropower in the New Zealand generation mix. The next greatest contributor is wind O&M (10-21%) which increases over time for all scenarios as the proportion of wind in the generation mix increases. T&D (6-7%), biomass O&M (3-7%) and distributed solar (1-4%) are smaller contributors to this indicator. Overall, the level of PED renewable increases over time for all scenarios as the proportion of renewable generation increases.

The biggest contributors to PED non-renewable (Figure K10) are gas O&M (40-61%) and coal O&M (22-43%). T&D (6-7%), distributed solar infrastructure (2-8%) and wind infrastructure (1-5%) contribute smaller amounts. Overall, the level of PED non-renewable decreases over time for all scenarios as the proportion of fossil fuel generation decreases.

The PED total indicator (Figure K11) is a combination of the above two indicators and the resulting change over time reflects the relative increase in total generation for the different scenarios. There are small increases in PED total for the scenarios with greater generation growth such as the MBIE Growth, Environmental and Disruptive and ICCC Accelerated Electrification scenarios and relatively stable or small decreases in PED total for the remaining scenarios. Overall, hydro O&M contributes the greatest amount (43-53%) followed by either gas O&M (12-19%) or wind O&M (7-15%) depending on the scenario. The next most significant contributors are coal O&M (6-13%), T&D (6-7%) and biomass O&M (2-5%).

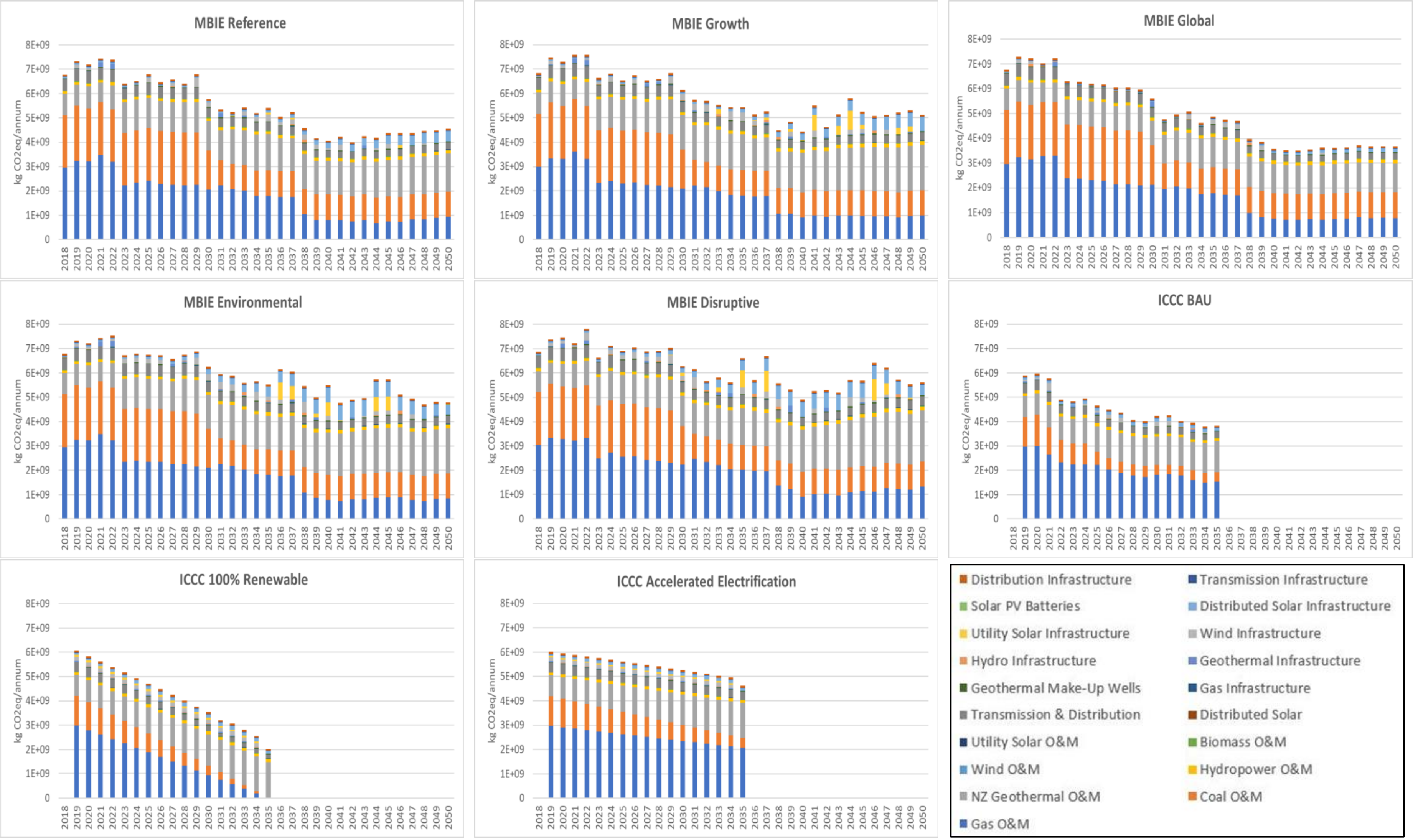


Figure K1: Annual Global Warming Potential excluding biogenic carbon 100 years (GWP$_{100}$ excl biogenic) by Scenario and Life Cycle Stage

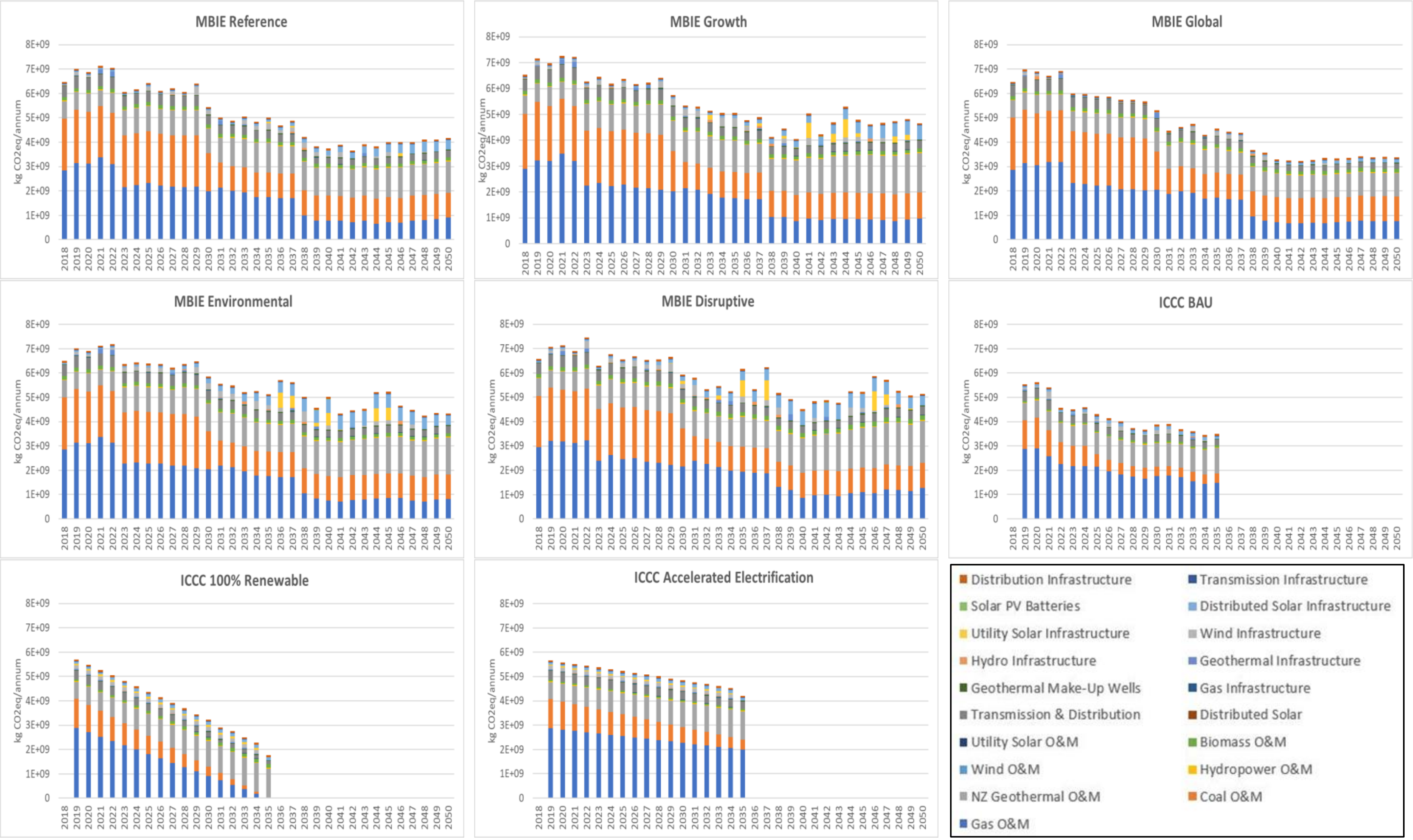
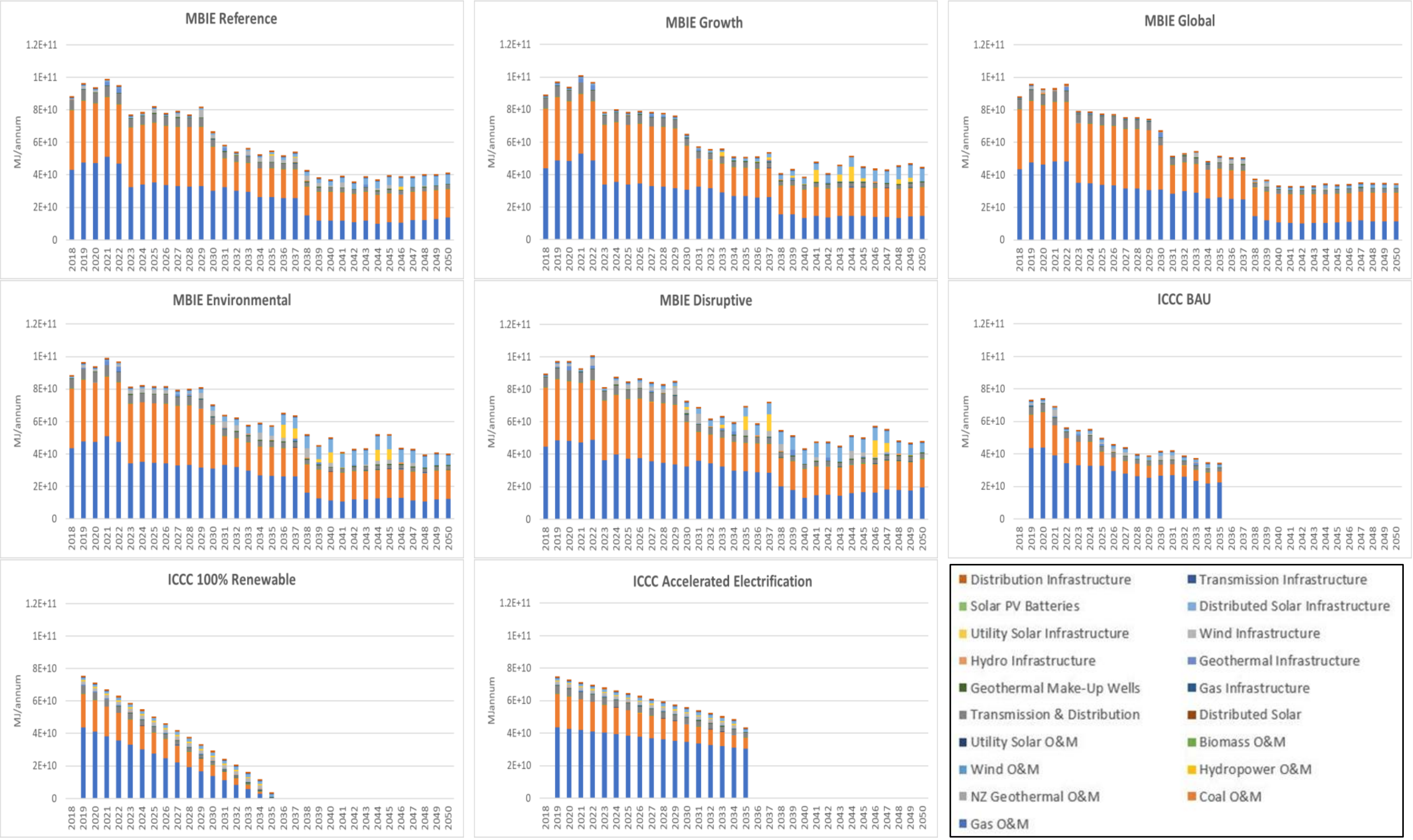


Figure K2: Annual Global Temperature Change Potential 100 years (GTP$_{100}$) by Scenario and Life Cycle Stage

Figure K3: Annual Abiotic Depletion Potential Elements (ADP elements) by Scenario and Life Cycle Stage


MBIE Reference

MBIE Growth

MBIE Global

MBIE Environmental

MBIE Disruptive

ICCC BAU

ICCC 100% Renewable

ICCC Accelerated Electrification

Figure K4: Annual Abiotic Depletion Potential Fossil (ADP fossil) by Scenario and Life Cycle Stage

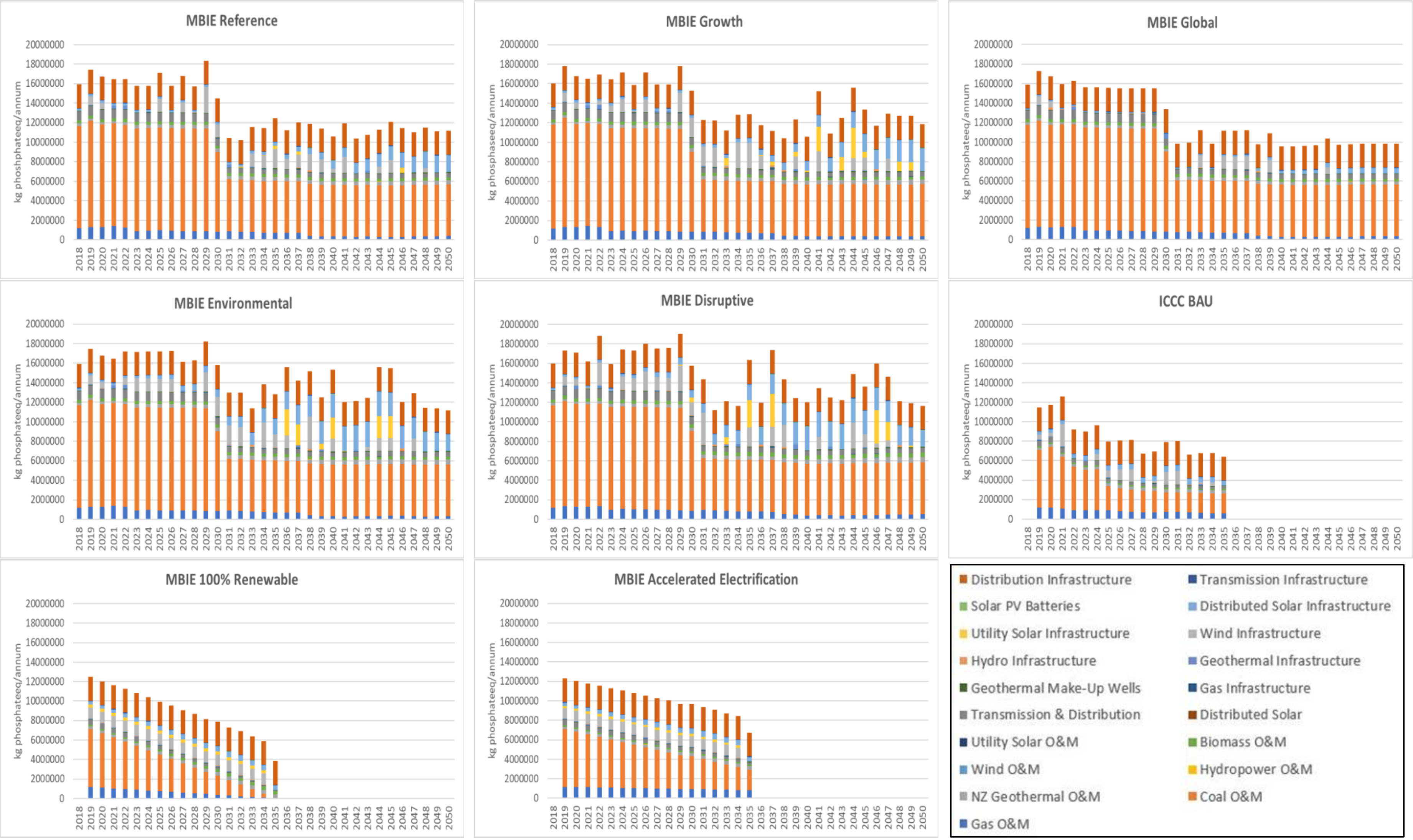


Figure K5: Annual Eutrophication Potential (EP) by Scenario and Life Cycle Stage

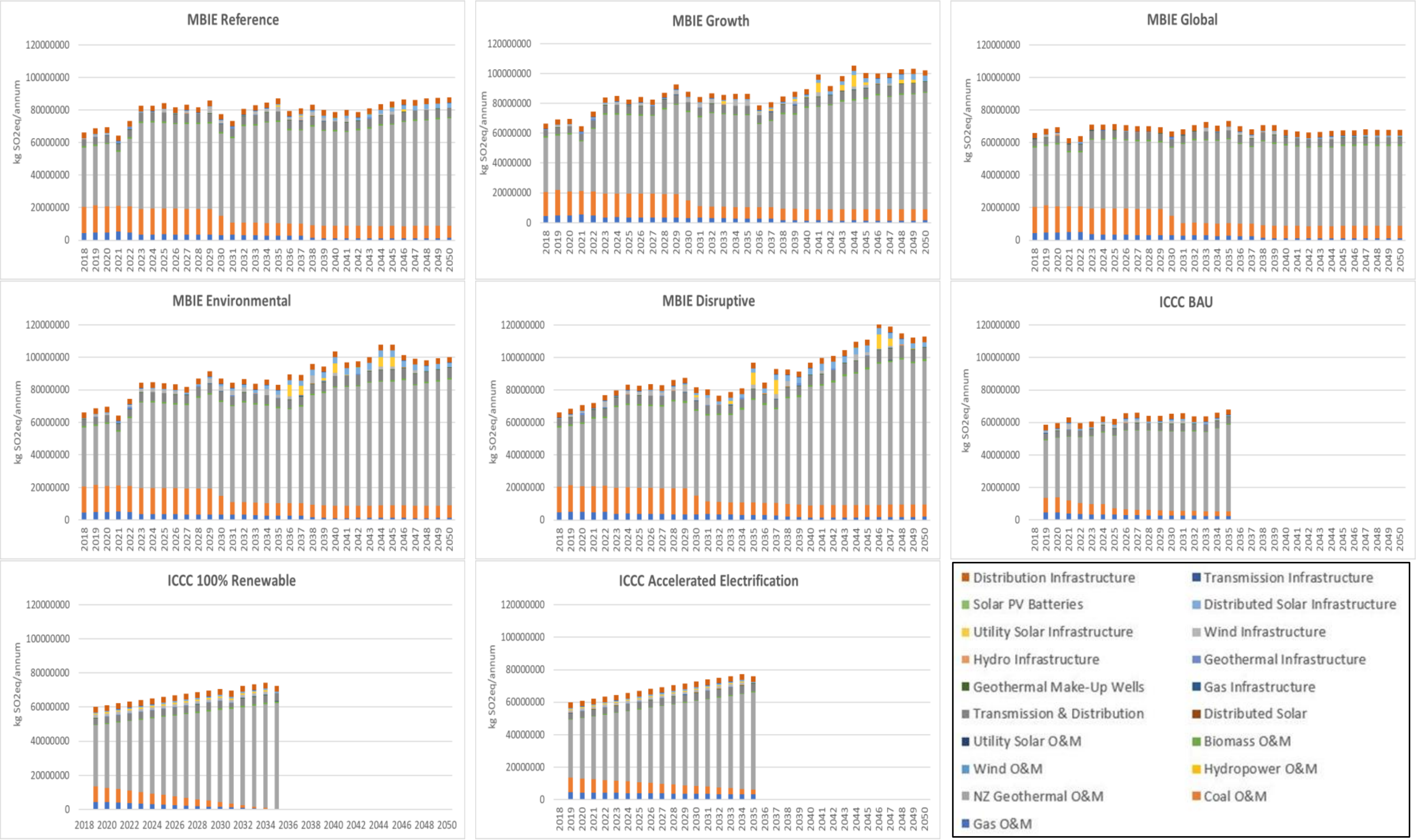


Figure K6: Annual Acidification Potential (AP) by Scenario and Life Cycle Stage

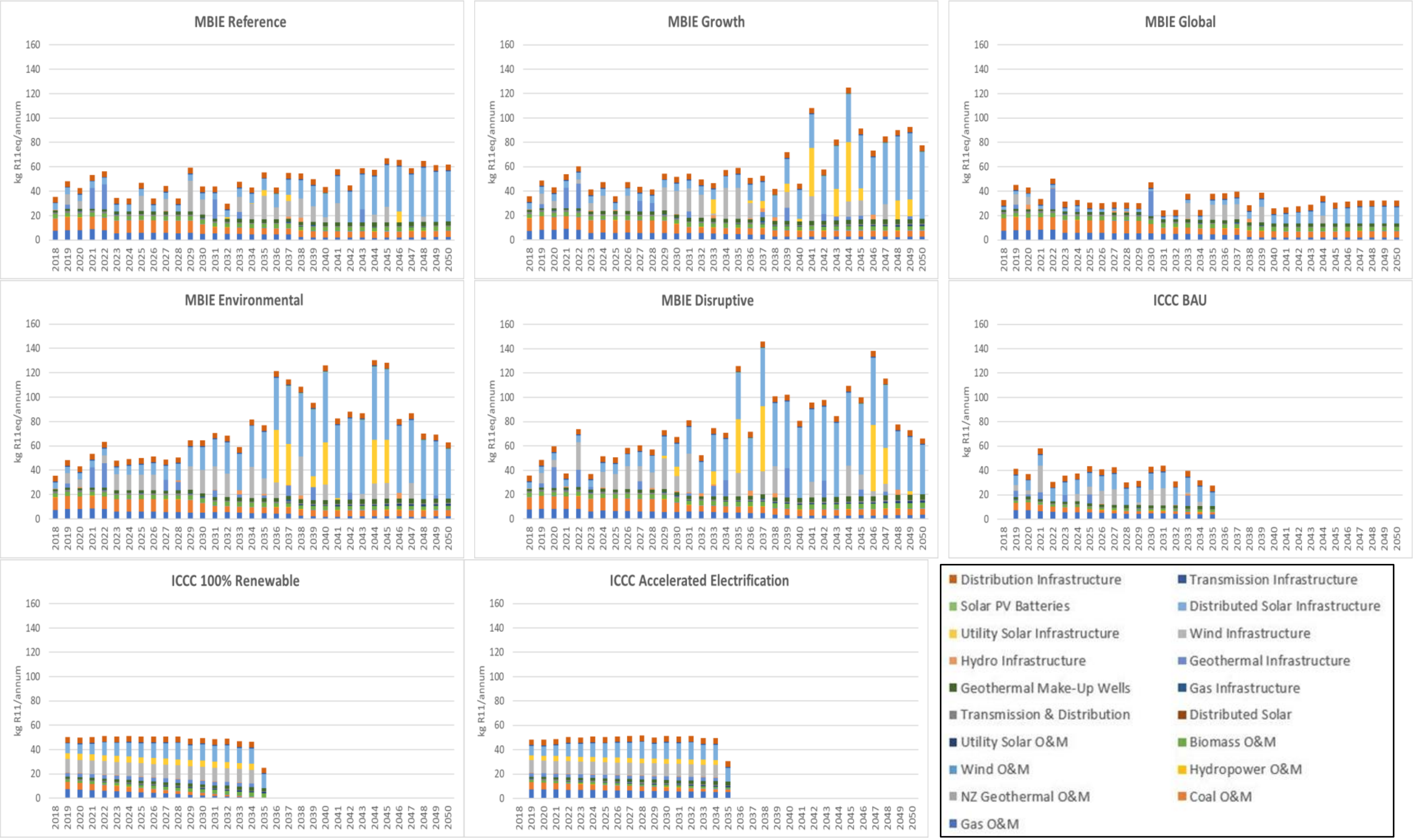


Figure K7: Annual Ozone Depletion Potential (ODP) by Scenario and Life Cycle Stage

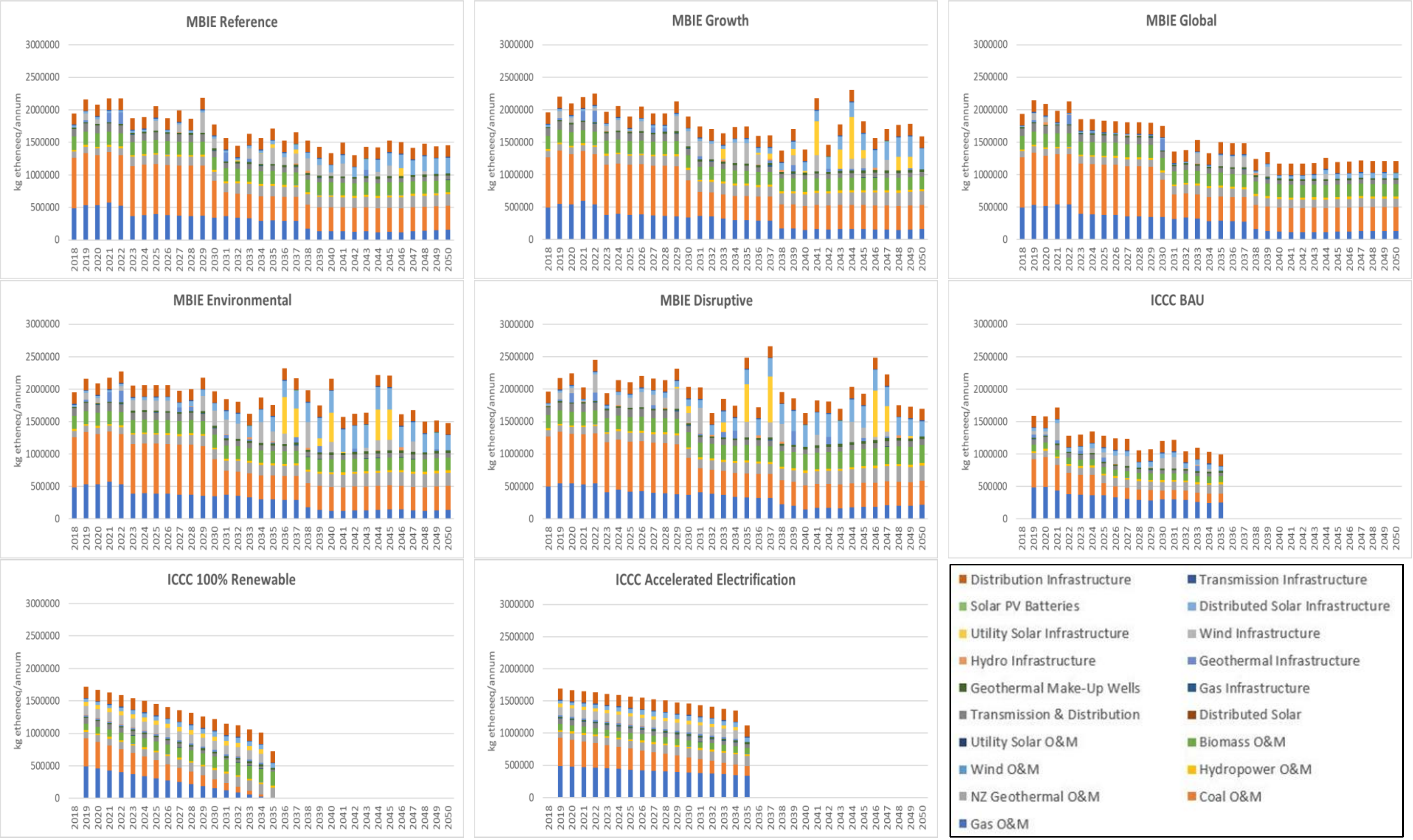


Figure K8: Annual Photochemical Ozone Creation Potential (POCP) by Scenario and Life Cycle Stage

Figure K9: Annual Primary Energy Demand from Renewable Resources (PED renewable) by Scenario and Life Cycle Stage

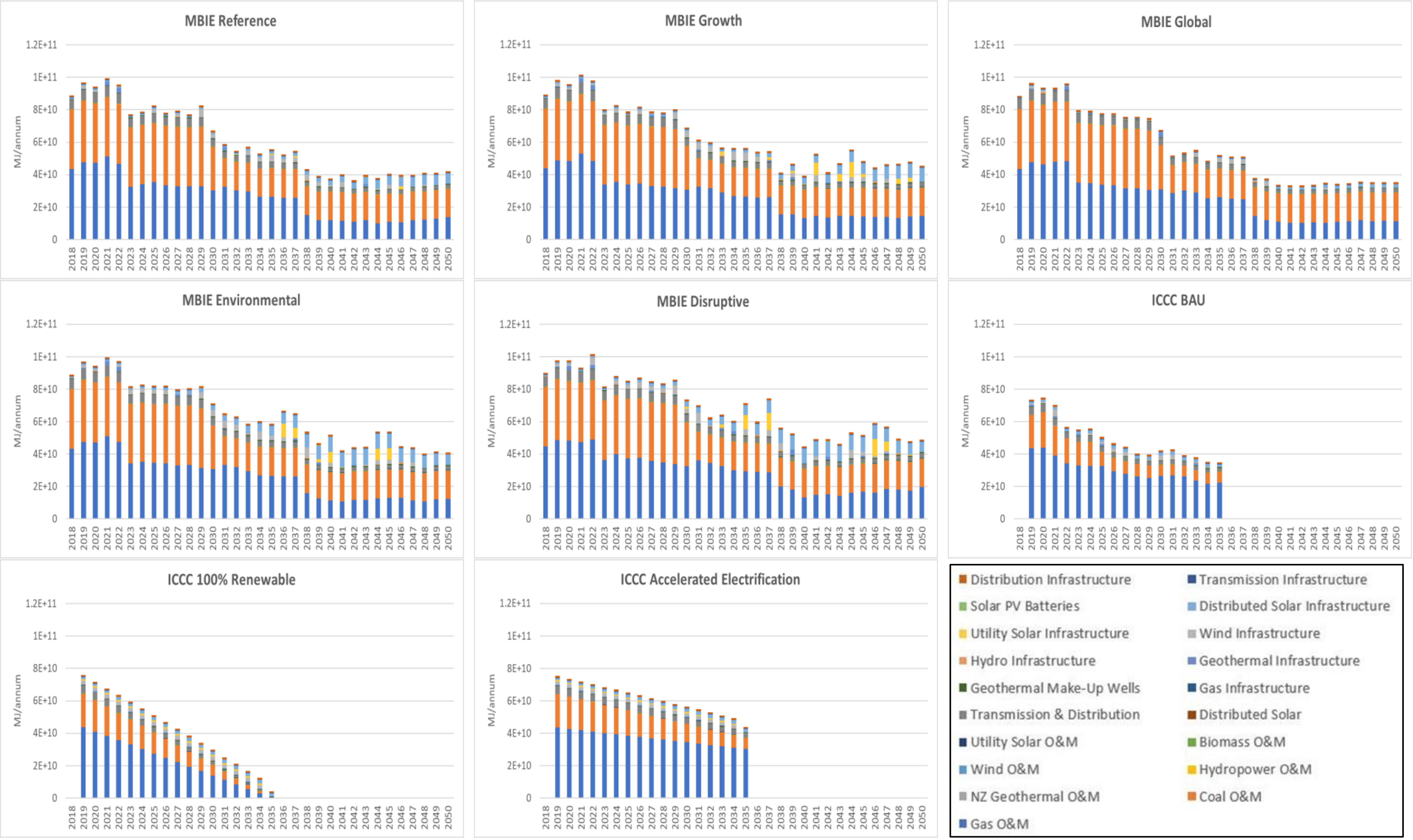


Figure K10: Annual Primary Energy Demand from Non-renewable Resources (PED non-renewable) by Scenario and Life Cycle Stage

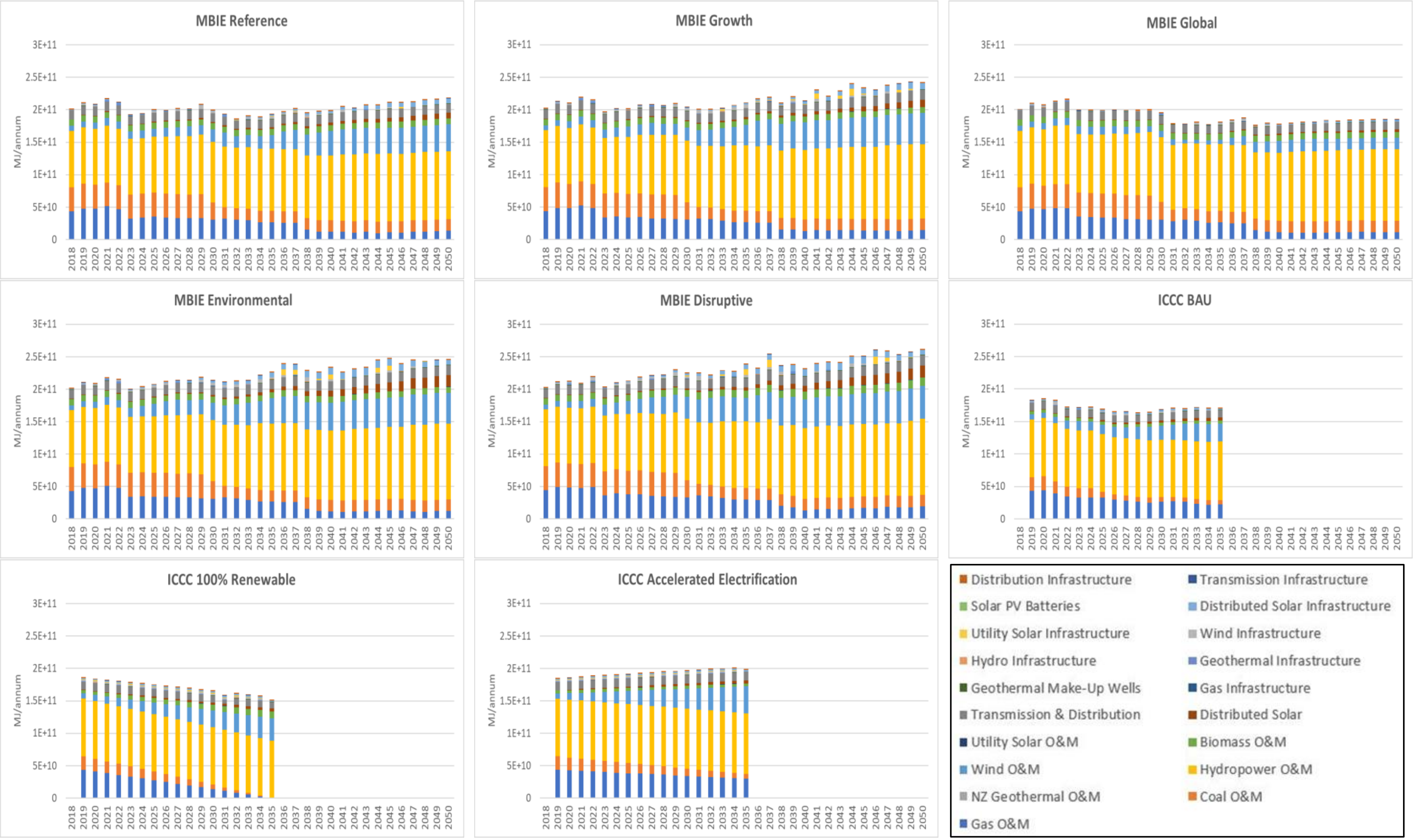


Figure K11: Annual Primary Energy Demand from Renewable and Non-renewable Resources (PED total) by Scenario and Life Cycle Stage