

Transitions in electricity systems towards 2030

An ICChemE Energy Centre Green Paper

Effective policy to combat climate change needs to be shaped by three guiding observations: firstly water, energy, food, and other natural resource systems are all inter-connected and must be considered together; secondly global poverty and inequity must be addressed to ensure communities are less vulnerable to the impacts of climate change; and thirdly understanding that these issues of scale, dynamics and uncertainty across the broad socio-economic-environmental-technical sphere requires comprehensive system-analytic tools to demystify their complexity and support decision-making.

The power sector will be pivotal to transitioning to a low-carbon economy. This transition demands significant changes to current electricity systems. It requires a reduction in carbon intensity through a shift to low-carbon generation, improving energy efficiency in the sector, and a decline in electricity demand. IPCC modelling of mitigation approaches, that result in stabilising emission levels between 430 and 540 ppm CO₂, envisage that approximately 80% of generation in 2050 is supplied by low-carbon sources such as renewable energy, nuclear power, and fossil fuel plants with carbon capture and storage (CCS) technology. By 2100, fossil fuel generation without CCS should become obsolete. The question remains of whether the power sectors in individual countries are seeing the changes necessary to transition to a low-carbon energy system. As fossil fuel generation capacity can operate for decades, capacity that is currently being constructed has an impact on future emission levels. Policies and market incentives can both enable and inhibit change.

Current trends and installation rates in Australia, China, India, Malaysia, Singapore, South Africa and the UK were examined in order to determine what the electricity system in these countries is likely to look like towards 2030. Any real effort to mitigate climate change must be a combined and coherent international effort, thus cross-comparison of policy frameworks between countries must be carried out. In order to facilitate the cross-comparison of each of these countries, their electricity systems, policies and contribution towards mitigating climate change, were analysed using our *condensed principles of rational energy policy*.

		Australia	China	India	Malaysia	Singapore	South Africa	UK
Condensed principles of rational energy policy:								
E	Evidence-based – Policies must be evidence-based and communicated in a transparent manner							
N	Negative emissions – Policies should unambiguously aim at an absolute reduction in anthropogenic CO ₂ emissions							
E	Energy efficient – Energy efficiency should be pursued wherever possible							
R	Renewable energy – Policies should lead to the deployment and grid-connection of renewable energy							
G	Governance – Governments must avoid policy reversal or change, and honour standing policy commitments							
Y	Years ahead – Long-term policies are essential to provide long-term investor confidence							
Overall								

Conclusions

1. Emphasis on stimulating economic growth is evident in all countries



Climate change mitigation efforts are almost exclusively implemented if they are in-line with economic objectives. In Australia, environmental measures such as the carbon tax were repealed in part because they were believed to hamper international competitiveness. Chinese economic growth was hindered by a dependence on foreign energy imports, leading the nation to promote low-carbon energy sources to diversify its electricity mix. Malaysia's fuel-switching is driven by the desire to increase export earning as a large LNG exporter.

2. Energy security concerns promote the diversification of the electricity mix



China and Singapore are net importers of energy, and are investing in LNG terminals in order to diversify their supply of natural gas. China is also investing in infrastructure to overcome domestic transportation bottlenecks, and is promoting renewable energy generation. The Malaysian government is diversifying its generation mix to coal and hydropower to continue exporting its natural gas resources. India has long term ambitions to increase the proportion of both nuclear and renewable energy in its electricity system as a way to exploit domestic resources and limit the dependence on energy imports.

3. A key driver of capacity expansion and improvement is shortages in electricity supply



China and India expect electricity demand to continue increasing as access to electricity increases and demand from industry grows to fuel growth. Both are investing in new generation capacity, as well as in the transmission grid in order to reduce transmission losses and improve security of supply. This is also critical in India, where transmission losses are in the range of 20-30% of electricity generated. South Africa's economic growth is hindered by widespread blackouts. It is thus imperative that new capacity is constructed quickly. As South Africa has large coal reserves, coal-fired generation is likely to increase.

4. Private sector investment is key to expanding electricity generation and fuel infrastructure growth



State-owned companies control the majority of electricity generation in China, India and South Africa. As national capacity targets in India are missed, the private sector is seen as necessary to increase investment in transmission infrastructure and generation capacity. South African Eskom is also facing financial difficulties and thus private sector procurement programmes have been launched to increase investment in renewable, coal-fired and gas-fired energy sources. The central government in China is promoting greater private sector investment to move away from its traditional government-led model.

5. There is a lack of long-term planning beyond 2030 in the electricity sector



Except for the UK, few countries have energy policies beyond 2030. Australia's Renewable Energy Target for 2020 does not specify which renewable energy sources should be installed. A lack of coordination in both India and Malaysia has created uncertainty for investors. Singapore has an overcapacity in the system and thus limited targets for generation. The South African approval process for capacity targets has faced delays, thus investments are still based on old plans. China has detailed 2020 renewable energy targets, but has not outlined its installed capacity for thermal generation.

At the 21st Conference of the Parties (COP21), the Paris Agreement was adopted. This will come into effect in 2020, empowering all countries to act to prevent average global temperatures rising above 2°C. Solving the climate challenge is a whole world problem, and a problem that can't be solved by working in alone. The IChemE Energy Centre calls on all countries of the world to work together to ensure we apply rational energy policies.

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A study on

Transitions in Electricity Systems Towards 2030

Examining:
Australia, China, India, Malaysia, Singapore, South Africa
and the United Kingdom

For
The Energy Centre of the Institution of Chemical Engineers
(IChemE)



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1 Executive Summary

This study was commissioned by the Institution of Chemical Engineers (IChemE) as a review of the installed electricity generation capacity in Australia, China, India, Malaysia, Singapore, South Africa and the UK. These countries were chosen owing to international significance and large IChemE membership.

The Intergovernmental Panel on Climate Change (IPCC) concludes that anthropogenic greenhouse gas emissions are the chief cause of global warming. The consumption and production of energy accounts for approximately two-thirds of global anthropogenic greenhouse gas emissions. Further, one-third of total emissions arise from the power sector. The decarbonisation of this sector is therefore key to achieving global reductions in greenhouse gas emissions, particularly given the widespread availability of technologies available and the possibilities for electrifying other sectors of the economy (namely the heating and transport sectors).

Each chapter in this study follows a common structure. The first section examines the nation's CO₂ emission levels and climate change targets. The second section then outlines how the electricity sector is managed, fossil fuel reserves and resource potential, as well as patterns in energy trade. This is followed by an examination of current energy policies and drivers, in order to establish how these have influenced the current generation mix. Finally, the potential impact of these policies is examined wherein we assess likely transition pathways and whether they are consistent with a reduction in power sector CO₂ emissions.

Country-Specific Findings

Australia

Energy-intense heavy industries are integral to the Australian economy. The main policy driver shaping Australian energy policy is the need to maintain Australia's competitiveness on international energy markets, as well as ensuring affordable energy domestically. The Federal Government repealed key parts of its Clean Energy Act in 2014, including a carbon tax and plans to implement a nation-wide emission trading scheme in order to reduce costs to households and industry. It is important to note that whilst the carbon tax etc. was presented as being chiefly responsible for cost increases, the reality was that the majority of the costs were associated with spending on upgrading the electricity transmission infrastructure. This policy reversal has significantly impacted government projections regarding the future state of the electricity sector. While business-as-usual projections published in 2012 indicated that coal-fired generation would decline to 13% of power generation by 2050, updated projections predict this share will increase to 65%. Gas-fired generation and renewable energy generation, while previously estimated to increase to 36% and 51% respectively, are estimated to fall to 15% and 20% respectively. CCS is not likely to be deployed by 2050 under the current policy climate, as it is not yet cost-competitive. The government has indicated that it will not

implement policies to force inefficient generation capacity out of the market. Thus, Australia's power sector emissions are likely to continue rising in the foreseeable future.

China

China is restructuring its economy, shifting away from a government-led investment model towards greater domestic consumption, the growth of the service sector, and a larger emphasis on environmental protection. The central government pledged to peak emissions by 2030, although various studies indicate that it is possible a peak will be achieved closer to 2025. The government envisages that the majority of China's emission reductions will be achieved through energy efficiency measures. This is supported by fuel-switching from thermal energy to low-carbon sources. As a result, the share of coal-fired generation has been declining since 2007 and inefficient thermal capacity is increasingly being shut down and being replaced by supercritical power plants. Government targets promote gas-fired generation, nuclear energy and a larger share of renewable energy in the generation mix. Renewable energy generation, however, is facing constraint, as approximately 16% of installed wind capacity was not connected to the grid in 2013. In order to address this, the government is investing in renewable energy and plans to release the Renewable Energy Portfolio Standard in 2015 in order to ensure that renewable energy is granted priority access to the grid. China's carbon intensity of generation has been decreasing since 2003. It is likely that this trend will continue as China invests in low-carbon sources of energy. The government is keen to stress that these measures are being implemented due to domestic considerations. This includes concerns regarding the effect of air pollution on public health, China's dependence on imports to satisfy its energy demand, and the intention to reduce government-led spending in favour of greater domestic consumption to foster growth.

India

Energy policy in India is focused around increasing energy provision to the 25% of the population that lack access to electricity and enhancing energy security through decreasing import dependence. The carbon intensity of electricity generation in India is the highest in the world at 964gCO₂/kWh due to the dominance of fossil fuel capacity and inefficiencies in electricity infrastructure. The power sector continues to have a significant shortfall between supply and demand, especially during peak demand hours. Part of the reason for this is due to the inability of domestic coal production to keep up with the increasing demand for power. Generation companies also consistently fail to meet capacity targets outlined by the government, leading to low investor confidence. The segregated nature of government departments related to energy policy in India results in multiple, conflicting targets for capacity. Renewable capacity in India has grown significantly from 1.2GW in 2000 to 31.7GW in 2014, mainly driven by state level policies. However, the new targets outlined for renewable energy towards 2020 seem to be very ambitious and will require very significant acceleration in deployment. The transmission losses in the electricity networks are very high, with estimates between 23-30%, and have been stated as a key barrier to increasing renewable energy

deployment. As the most cost effective option for rapidly addressing power shortages and increasing demand, coal fired generation will continue to play an important part of the electricity system. A challenge around private sector investment in the power sector in India arises from the tradition of providing free and unmetered power to local industries. There are significant opportunities to improve the average efficiency of India's coal fleet as well as increase the proportion of renewable energy, natural gas and nuclear in the electricity mix. In this context, it is important to note that India has a fast growing LNG import demand, with four LNG import terminals build in recent years with one more planned.

Malaysia

Under the New Economic Model initiated in 2010, Malaysia has the objective to reach high-income status (as classified by the World Bank) by 2020. This has been a major driver in shaping Malaysia's energy policies. Malaysia's considerable fossil fuel reserves have led to the generation capacity being dominated by natural gas and established Malaysia as a major global exporter of LNG. However, declining production rates have been a driver for the diversification of the energy mix. The country has therefore been importing coal to power its expanding capacity base and to allow the continuation of long-term LNG contracts within the Asian market. Although Malaysia has significant potential for exploiting biomass and solar resources, renewable energy (excluding hydropower) only accounted for 0.8% of electricity generation in 2014. The Malaysian government is compromising energy security by increasing their dependence on imported coal and the decarbonisation of the energy sector is not seen to be a main concern. With the electricity system shifting towards being more heavily focused on coal-based capacity, Malaysia is committing to fossil fuel generation for the foreseeable future and emissions from the power sector will continue to increase. This trend toward a more carbon intensive electricity system indicates to the international community that Malaysia do not have a long-term vision for a low carbon electricity sector.

Singapore

Energy policy in Singapore has been focused on securing a reliable and affordable supply of energy for their country as well as diversifying their energy sources. Singapore has no domestic fossil fuel resources and has limited potential for renewable technologies other than solar energy. The country therefore imports the majority of its energy needs via natural gas pipelines from Indonesia and Malaysia. Singapore currently has overcapacity in its electricity system as a number of new combined cycle gas turbine (CCGT) plants have come online in recent years. 97% of installed capacity consists of natural gas fired generation with the remaining share made up of waste-to-energy plants and a small amount of solar capacity. There is much R&D effort underway in areas of clean energy but large-scale deployment has yet to materialise. Solar PV installations reached 33MW in 2015, which is less than 10% of the 2020 government target of 350MW. Having shifted electricity generation away from carbon intensive oil capacity to high efficiency CCGT plants, the carbon intensity of electricity production has decreased significantly over the past three decades. Singapore have pledged

to reduce their emission intensity of GDP by 36% from 2005 levels by 2030 with an aim to peak emissions by that year. Despite having strong policies in place to tackle other environmental issues such as air pollution, climate change targets are not deemed ambitious enough based on Singapore's economic and technical capabilities. The emissions intensity target can be met through current energy efficiency policy measures, with minimal additional effort.

South Africa

South Africa has been facing an electricity shortage since 2008 due to unplanned maintenance outages and years of underinvestment in generation capacity by the state-owned generation company Eskom. Addressing these shortages is the main driver behind South Africa's energy policies. Approximately 91% of South Africa's generation in 2014 was supplied by coal-fired power plants. Eskom operates four open-cycle gas turbines, which run on kerosene and diesel oil in order to limit power outages and meet demand during disruptions. South Africa's Integrated Resource Plan sets installation targets towards 2030, and outlines the need for an additional 55GW of generation capacity. Private sector investment is seen as a way to diversify supply and ensure targets are met, and the government has mandated that Independent Power Producers should construct 30% of all new generation capacity. Power outages are expected to continue until 2017 due to maintenance issues at South Africa's nuclear power plant, and construction delays at the supercritical coal-fired power plants Medupi and Kusile. Government projections predict that emissions from the power sector will continue to rise towards 2030, as the country continues to rely on coal-fired generation capacity for the majority of its electricity supply.

United Kingdom

The United Kingdom (UK) has a fossil fuel dominated energy system since the beginnings of industrialisation. Today the electricity mix includes a share of 61 % from fossil fuels, 19 % from nuclear, 11 % from wind, 2 % from hydro, and 8 % from other sources. The carbon emissions in 2013 related to the energy sector reached 189.7 Mt_{CO2-eq}, accounting for over 30 % of the total 568.3 Mt_{CO2-eq}. The legally binding 2008 Climate Change Act mandates a reduction in total greenhouse gas emissions by 34 % by 2020 and 80 % by 2050. Four consecutive carbon budgets, each for a five year time period, state the average annual emissions and an absolute maximum emission level are guiding the way to reach the 2030 target. The first carbon budget ended 2012 and has been met. The National Renewable Action Plan was announced in 2010 as fulfilment of the EU directive and guidepost for UK's strategy to meet the EU climate targets. It summarises existing and planned policies and pledges to aim at overachieving the EU wide goals. Current policies, such as the Renewable Obligation and Electricity Market Reform are directing at incentivising low-carbon power generation as well as investment in new low-carbon capacity. Further, in a market-driven approach, the establishment of a Green Investment Bank is providing financial support to commercial projects as well as relevant research. However, there is a change of direction from the current government as it is cutting

subsidies for certain renewable power generators such as small-scale PV and onshore-wind. Additional uncertainties and inconsistencies in existing regulations have rather delayed instead of accelerating new investment in the energy sector. The UK is aware of the energy trilemma characterised by balancing carbon avoidance, cost, and the security of electricity supply. However, a greater level of cross-parliamentary consistency in long-term energy system planning will be necessary to successfully meet the 2050 target.

Conclusions

1. Emphasis on stimulating economic growth is evident in all countries.

All countries examined in this study are concerned with promoting economic growth. Climate change mitigation efforts are almost exclusively implemented if they are in line with economic objectives. In Australia, for example, environmental measures such as the carbon tax were repealed in part because they were believed to hamper the nation's international competitiveness. By contrast, Chinese economic growth was hindered by a dependence on foreign energy imports and environmental degradation, leading the nation to promote low-carbon energy sources in order to diversify its electricity mix. South Africa and India are both concerned with increasing electricity supply in order to address shortages, as these hinder economic growth. Malaysia's fuel-switching from gas-fired generation to coal-fired generation is driven by the desire to increase export earning by remaining a large LNG exporter. Similarly, Singapore is a major hub for oil and petroleum trade, and the nation wishes to expand its petrochemical industry in order to increase GDP.

2. Energy security concerns promote the diversification of the electricity mix.

China and Singapore are net importers of energy, and are both investing in LNG terminals in order to diversify their supply of natural gas. China is also investing in infrastructure in order to overcome domestic transportation bottlenecks, and is promoting renewable energy generation as a viable domestic source of electricity generation. The Malaysian government, by contrast, is diversifying its generation mix to coal and hydropower in order to continue exporting its natural gas resources. India has long term ambitions to increase the proportion of both nuclear and renewable energy in its electricity system as a way to exploit domestic resources and limit the dependence on energy imports.

3. A key driver of capacity expansion and improvement is the need to address shortages in electricity supply.

This is mainly evident in China, India and South Africa. China and India both expect electricity demand to continue increasing as access to electricity increases, and demand from industry grows to fuel economic growth. Both nations are investing in new generation capacity, as well as investing in the transmission grid in order to reduce transmission losses and improve security of supply. This is particularly critical in India, where transmission losses are in the

range of 20-30% of electricity generated. South Africa's economic growth is hindered by widespread blackouts. It is thus imperative that new capacity is constructed quickly. As South Africa has large coal reserves, coal-fired generation is likely to increase.

4. In countries with large state-owned electricity actors, private sector investment is seen as key to diversifying the electricity mix and stimulating infrastructure enhancements.

The state-owned generating companies own the majority of electricity generation in China, India and South Africa. As these companies continue to miss national capacity targets in India, the private sector is seen as necessary in order to increase investment in transmission infrastructure and generation capacity. Similarly, South African Eskom is facing financial difficulties and thus several private sector procurement programmes have been launched in order to increase investment in renewable energy sources, coal-fired generation, and gas-fired capacity. The central government in China is promoting greater private sector investment in order to move away from its traditional government-led investment model.

5. There is a lack of long-term planning beyond 2030 in the electricity sector in the countries examined.

With the notable exception of the UK, none of the countries examined have energy policies or targets in place towards 2050. Australia's Renewable Energy Target for 2020 does not specify which renewable energy sources should be installed. Furthermore, the target was reviewed and lowered in 2015, creating further uncertainty regarding the future of Australia's environmental policies. A lack of coordination between ministries in both India and Malaysia has created an uncertain environment for investors, as well as concerns regarding the achievability of their targets towards 2022 and 2025, respectively. As Singapore currently has an overcapacity in the system, the nation has limited targets for generation. While South Africa has capacity targets to be achieved by 2030, these are supposed to be updated every two years. As the approval process of the latest update has faced delays, investment decisions are still based on the original plan. Finally, while China has detailed renewable energy targets towards 2020, it has not yet outlined its intended installed capacity for thermal generation sources.

International cross comparison

We have noticed that there is a relative lack in cross- comparison of policy frameworks in the context of combatting climate change. Given that any real effort to mitigate climate change must, of necessity be a combined and coherent international effort, is it our considered view that this is a gap which should be addressed.

In order to facilitate the cross country comparison of each of these countries, their energy systems, policies and likely contribution towards combatting climate change, the following six criteria are proposed:

1. Policies concerning energy and climate change must be evidence-based and communicated in a transparent manner both nationally and internationally – this includes the magnitude and basis for emission targets, rationales for spending.
2. Energy efficiency should be pursued wherever possible as this is ultimately a route to both cost and emission reduction.
3. Policies should unambiguously aim at an absolute reduction in anthropogenic CO₂ emissions – the aim should be to transition to a system with near-zero CO₂ emissions from the energy sector by 2050.
4. Policies should lead to the rational deployment and grid-connection of renewable energy where this deployment serves to reduce CO₂ emissions and enhance energy security – this is not the same as ideologically driven technology deployment; ends must not be confused with means.
5. Governments should avoid policy reversal or change wherever possible – if one parliament makes a policy commitment pertaining to the energy system, ensuing parliaments should honour this commitment, to do otherwise undermines investor confidence and can have supra-national unintended consequences.
6. Long term policies are essential to provide long term investor confidence – more and more, energy systems rely upon international private capital. As investments in the electricity system are multi-decadal in nature and carry relatively low rates of return, investor appetite for risk is typically very limited – legally binding long term goal contribute to reducing investment risk in the low carbon energy sector. This is key to enabling the required research, development and deployment of key technologies such as CCS. Ideally, this should come in the form of a 2050 target.

After some consideration, we have devised the acronym “ENERGY” in which we have tried to capture the spirit of the aforementioned six principles in a few words:

Condensed Principles of Rational Energy Policy

E – Evidence based

N – eNergy efficient

E – Emission reduction

R – Renewable energy

G – Governance

Y – Years ahead – a coherent long term policy

It is evident that this is a significant simplification of the original six principles, but it is our hope that this mnemonic will help facilitate the utilisation of these principles.

On this basis, we then apply this cross-comparison to our seven countries considering our six principles. For each criteria, we apply a score of -1, 0 or 1, where -1 implies a negative action, 0 implies little or neutral action and 1 implies a concrete and well defined positive action.

Table 1: ENERGY score card for the seven countries assessed in this study.

	Australia	China	India	Malaysia	Singapore	South Africa	UK
Evidence based	-1	1	0	0	1	0	1
Energy efficient	-1	0	-1	1	1	1	0
Emission reduction	-1	-1	-1	-1	-1	-1	1
Renewable energy	0	1	0	0	1	-1	1
Governance	-1	0	-1	0	0	-1	-1
Years ahead	-1	0	-1	-1	-1	-1	0
Overall Assessment	-5	1	-4	-1	1	-3	2

As can be observed from Table 1, we consider the UK to be internationally leading in terms of energy policies that will contribute to the mitigation of climate change. The UK's 2008 Climate Change Act is a key asset here. To our knowledge, the UK is the only country amongst those studied with a) a legally binding 2050 target and b) an absolute, as opposed to relative target. However, specific measures to incentivise energy efficiency appear to be absent, and recent policy changes, however justified, were profoundly unhelpful. Similarly to the UK, Singapore appears to be taking some steps in the right direction, however, their relatively small size and limited natural resources acts to limit what steps they can take. However, given their income level, it is evident that they could have more stretching emission mitigation targets.

Tying with Singapore is China who is now the world's largest emitter of CO₂ – which, given their size and population, is not entirely surprising. Whilst their energy system is primarily dependant on fossil fuels, they are simultaneously the world's largest investor in renewable energy, and have recently pledged substantial greenhouse gas reduction targets in advance of COP21. In contrast to their neighbour, Singapore, Malaysia is relatively rich in a range of fossil and renewable energy resources, but owing to their focus on economic performance, they are actively moving away from gas-fired power plants and towards coal-fired power plants – which can only result in a marked increase in CO₂ emissions.

South Africa is also relatively rich in both space and resources but faces very different challenges. Their energy system is overwhelmingly dominated by fossil fuels and owing to their severe capacity constraints, they often employ carbon intense, inefficient peaking plant to provide near-baseload capacity. India is another example of a resource rich, emerging economy – however, here their existing energy system suffers from poor efficiency as well as, in general, poor access to energy, and increasing access to affordable energy is the Indian

government's primary concern. Similarly, the disconnect between Federal and State government policies results in confusing statements and goals. On the other extreme lies Australia whose current trajectory would appear to be actively detrimental to the effort to combat climate change. It is, in general disappointing to note that, from the perspective of climate change mitigation, the direction of travel is not positive.

It is evident that existing policies are, by and large, not sufficient to deliver a low carbon energy system by 2050, and substantially more effort and clarity on actions and targets are required from all countries in order to achieve this goal.

2 Introduction

Global mean surface temperature has risen since the 1950s, causing changes to the Earth's climate system that threaten the ecosystem services upon which humans depend for survival (IPCC, 2014a). Temperature extremes such as heat waves affect the ability to grow crops for food, rising sea-levels threaten to flood low-lying countries and urban megacities alike, and desertification caused by droughts is making land uninhabitable (IDDRI & SDSN, 2014). The International Panel on Climate Change (IPCC) concludes that anthropogenic greenhouse gas emissions (GHG) are extremely likely to be the chief cause of observed global warming (IPCC, 2014a). The same report asserts that without additional measures to reduce GHG emissions, global mean surface warming is likely to rise towards 2100 and lead to 'substantial species extinction, global and regional food insecurity, consequential constraints on common human activities and limited potential for adaptation' (IPCC, 2014a).

Recognising the need to reduce the impact of human activities on the climate system, the United Nations Framework Convention on Climate Change (UNFCCC) was established in 1992 (UNFCCC, 2015a). The ultimate goal of the UNFCCC is to 'stabilise greenhouse gas concentrations in the atmosphere at a level that will prevent dangerous human interference with the climate system' (UNFCCC, 2015a). In 2010, the Cancun Agreement was reached, which set a long-term target of limiting the global average temperature rise to below 2°C relative to pre-industrial levels (IEA, 2015). In order to reach this target, GHG emissions must be below 450 ppm carbon dioxide equivalent (CO₂e) by 2100 (van Vuuren, 2014). This translates into a reduction in anthropogenic GHG emissions of 40% to 70% by 2050. By 2100, GHG emissions need to approach zero (IPCC, 2014a).

The Kyoto Protocol of 1992 set internationally binding GHG emission reduction targets for Annex-I Parties to the Convention, which includes members of the Organisation for Economic Co-operation and Development (OECD) and other industrialising countries (UNFCCC, 2015b). The Kyoto Protocol's latest commitment period extends towards 2020. Negotiations for a post-2020 agreement have been underway since the Conference of the Parties (COP) in Copenhagen in 2009. It is hoped that negotiations at COP-21 in Paris in December 2015 will conclude negotiations and successfully lead to a binding agreement to reduce emissions beyond 2020 (IEA, 2015). Countries are expected to submit Intended Nationally Determined Contributions (INDC) before the summit. They serve as a basis for negotiations, as the INDCs outline the actions each country intends to take to mitigate or adapt to climate change, taking into account domestic considerations such as national priorities and capabilities (WRI, 2015).

COP-21 is seen as a critical juncture in the effort to mitigate climate change. The IPCC states that current mitigation efforts are insufficient to reduce the anthropogenic impact on the climate, and that ‘without additional mitigation efforts beyond those in place today, and even with adaptation, warming by the end of the 21st century will lead to high to very high risk of severe, wide-spread and irreversible impacts globally’ (IPCC, 2014a). In 2014, atmospheric GHG emissions were already 435 ppm CO₂e (IEA, 2015). Delaying action to mitigate emissions will make it increasingly difficult to transition to a pathway consistent with limiting global warming to 2°C (van Vuuren, 2014). Staying within the target will require significant action from governments and other actors to change the current energy system.

The consumption and production of energy accounts for approximately two-thirds of total anthropogenic GHG emissions (IEA, 2015). Energy-related CO₂ emissions have been increasing for the past four decades, rising by more than 50% between 1990 and 2015 (IEA, 2015). Electricity generation is one of the key drivers of this growth. The power sector accounted for approximately one-third of global energy-related CO₂ emissions in 2014, as shown in Figure 1 (IEA, 2015). This is due to a rising demand for electricity as emerging and developing economies continue to grow, as well as the reliance on fossil fuels for generation. In 2012, fossil fuel generation accounted for 68% of total electricity generation (IEA, 2014).

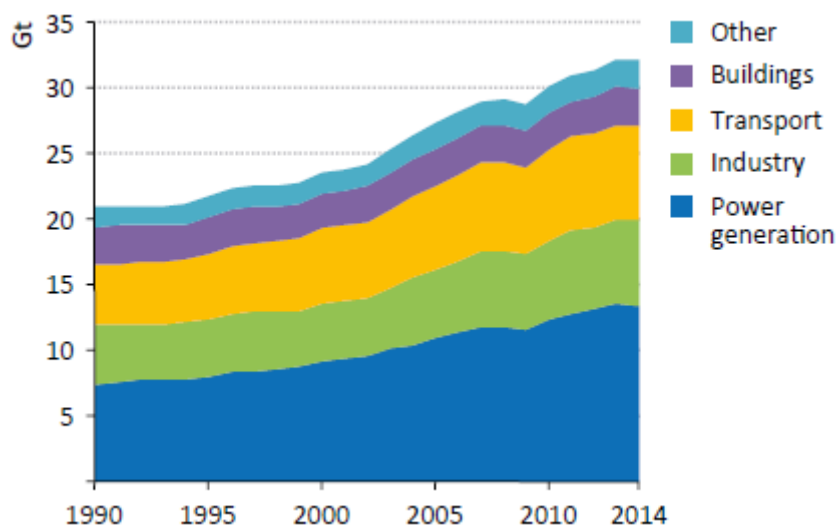


Figure 1: Global energy related CO₂ emissions by sector, 1990-2014 (IEA, 2015).

Decarbonising the electricity sector is seen as a key element to efficiently reducing a nation’s economy-wide emissions. This is due to the size and growth of sectorial emissions, as well as the availability of technology that enable emission reductions in the sector (IEA, 2014). Low-carbon technologies are increasingly becoming more efficient and cost-competitive. Furthermore, other energy- and emission-intensive sectors, in particular the transport and

heating sector, can be electrified (CCC, 2008). Thus, decarbonising the electricity sector can result in emission reduction across the economy. This has been recognised by countries worldwide. For example, the United Kingdom (UK) Committee on Climate Change asserts that an almost complete decarbonisation of electricity generation is necessary in order for the UK to meet its legislated target of reducing the nation's greenhouse gas (GHG) emissions 80% below 1990 levels by 2050 (CCC, 2008). Similarly, the European Union (EU) concludes that carbon dioxide (CO₂) emissions from electricity generation can approach zero by 2050 (EC, 2011). The power sector thus is envisaged to be pivotal to transitioning to a low-carbon economy (EC, 2011).

This transition requires significant changes to current electricity systems. It requires a reduction in carbon intensity through a shift to low-carbon generation, improving energy efficiency in the sector, and a decline in electricity demand (IDDRI & SDSN, 2014). IPCC modelling of mitigation approaches that result in stabilising emission levels between 430 and 540 ppm CO₂ envisage that approximately 80% of generation in 2050 is supplied by low-carbon sources such as renewable energy, nuclear power, and fossil fuel plants with Carbon Capture and Storage (CCS) technology (IPCC, 2014b). By 2100, fossil fuel generation without CCS should become obsolete (IPCC, 2014b). A question remains of whether the power sectors in individual countries are seeing the changes necessary to transition to a low-carbon energy system. As fossil fuel generation capacity can operate for decades, capacity that is currently being constructed has an impact on future emission levels. Policies and market incentives can both enable and inhibit change (IEA, 2015).

This report examines current trends and installation rates in Australia, China, India, Malaysia, Singapore, South Africa and the UK in order to determine what the electricity system in these countries is likely to look like towards 2030. This report aims to determine whether it is likely that there will be a reduction in emissions from power generation in these nations.

3 A Global Perspective

Figure 2 displays the total cumulative greenhouse gas emissions from 1850 to 2010 of selected countries and regions. The data includes emissions from land-use change and forestry (LULUCF), peat fires and decay, as well as non-CO₂ emissions such as CH₄. As shown, the United States and the 27 European Union Member States emitted the majority of GHG emissions from 1850 to 2010, accounting for 18.6% and 17.1% of total GHG emissions, respectively (den Elzen et al., 2013).

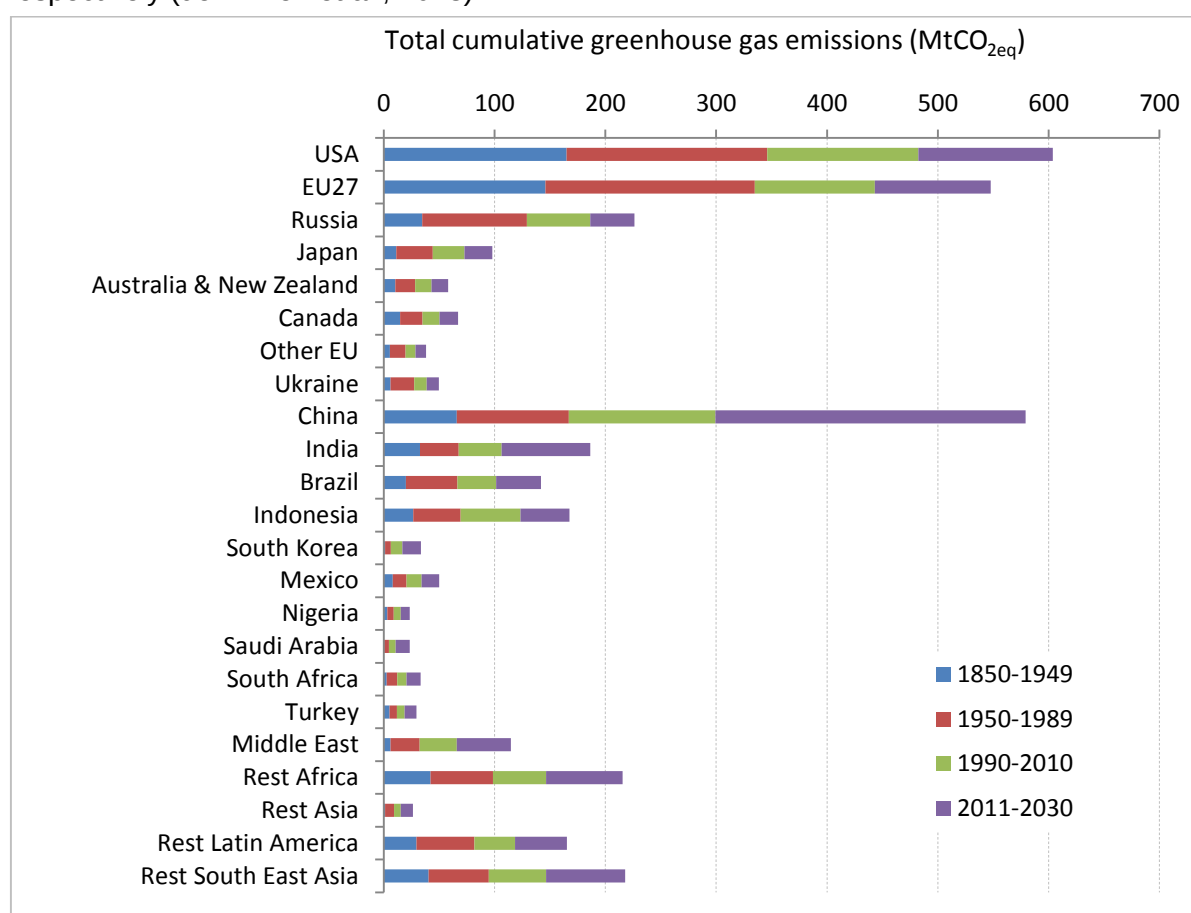


Figure 2: Total cumulative greenhouse gas emissions (den Elzen et al., 2013).

In climate change negotiations, China, India and other developing countries frequently argue that industrialised countries are the main cause of global warming due to their historic contribution to cumulative GHG emissions (den Elzen et al., 2013a). However, as Figure 2 shows, China's contribution to cumulative GHG emissions has rapidly risen since the 1950s. China's contribution to total GHG emissions from 1850 to 2010 is 11.6% and this places China third only behind the US and EU 27. While GHG emissions from the EU 27 and other developed countries have remained fairly stable since the 1990s, China's emissions continue to rise. China surpassed the US as the world's largest emitter of GHG emissions in 2004, and the world's largest CO₂ emitter in 2006 (den Elzen et al., 2013a). It accounted for 27% of global CO₂ emissions in 2014 (Newson, Cairns & Davis, 2010). India's CO₂ emissions have also risen steeply over the past 20 years and India's contribution to total GHG emissions from 1850 to 2010 is 4.1% (den Elzen et al., 2013b). This contribution ranks India fifth highest in the world

behind USA, EU27, China, Russia and Indonesia. India contributed 5.9% of global emissions in 2014 which is an indication of its rapidly increasing emissions.

Australia and New Zealand's cumulative GHG emission contribution is relatively small, accounting for 1.7% of the global total (den Elzen et al., 2013b). It is likely that Australia is responsible for the majority of this contribution, as it has historically accounted for a larger share of the combined emissions from Australia and New Zealand. From 1970 to 2014, for example, Australia was responsible for more than 90% of their combined emissions (Enerdata, 2014a). As Australia accounts for a relatively small percentage of cumulative historic emissions, the Australian parliament emphasises the need to examine the actions of larger emitters such as the US, EU and China when considering climate change mitigation actions (Talberg, 2015). In 2013, however, Australia was the 15th largest global emitter of energy-related CO₂ emissions, emitting 379 MtCO₂ (Enerdata, 2014a).

According to Den Elzen et al. (2013b), South Africa's relative contribution to cumulative global greenhouse gas emissions from 1850-2010 is 0.8%. This relative contribution rises to 1.2% of the global total when excluding non-CO₂ emissions and land-use change emissions. According to the EDGAR database for 2014, Malaysia accounted for 0.52% of global greenhouse gas emissions and Singapore accounted for 0.1% (EDGAR, 2014).

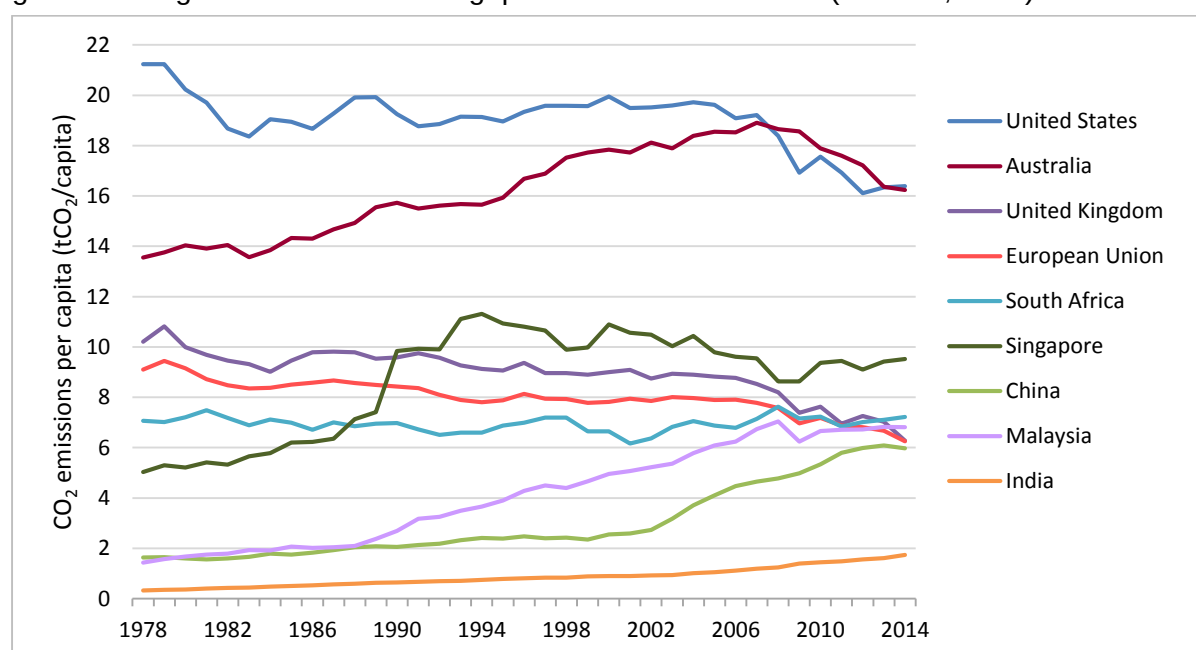


Figure 3: The change in CO₂ emissions per capita for selected countries from 1978-2014 (Enerdata, 2014a).

Where a certain country ranks globally in terms of contribution to GHG emissions can depend greatly on the perspective taken. A good example of this is the difference between comparing per capita CO₂ emissions and total absolute emissions. Countries such as the USA and Australia rank highly for both cumulative emissions and per capita CO₂ emissions. Figure 3 outlines the change in per capita emissions for various countries between 1978 and 2014. Emitting 16.2 tCO₂/capita in 2014, Australia has the highest per capita emissions in the OECD,

and the 12th highest worldwide (Enerdata, 2014a). Although China is ranked 46th globally on a CO₂ per capita basis, its per capita emissions have been increasing rapidly since 2002. China's per capita emissions rose to 5.98 tCO₂/capita in 2014, which is close to the UK average of 6.28 tCO₂/cap and the EU average of 6.26 tCO₂/cap (Enerdata, 2014a).

It can be observed in Figure 3 that whilst Singapore contributes a small percentage to overall emissions, its per capita CO₂ emissions are particularly high and increased rapidly between 1970 and 1995. This is the opposite case for India, where the cumulative emissions have a larger contribution to global emissions but the per capita emissions are one of the lowest in the world at 1.7tCO₂/capita. Malaysia's per capita emissions have also increased steeply over the past 25 years and have now risen above the average for the EU in 2014. South Africa's per capita emissions have remained fairly stable over the past 40 years. Emitting 7.2 tCO₂/capita in 2014, South Africa's per capita emissions are above the world average of 4.26 tCO₂/capita and the EU average of 6.26 tCO₂/capita (Enerdata, 2014a). It is interesting to note that per capita emissions in the UK and the EU have been steadily declining over the past 25 years, mainly as a result of increasing energy efficiency and shifts towards low carbon energy (IEA, 2014b).

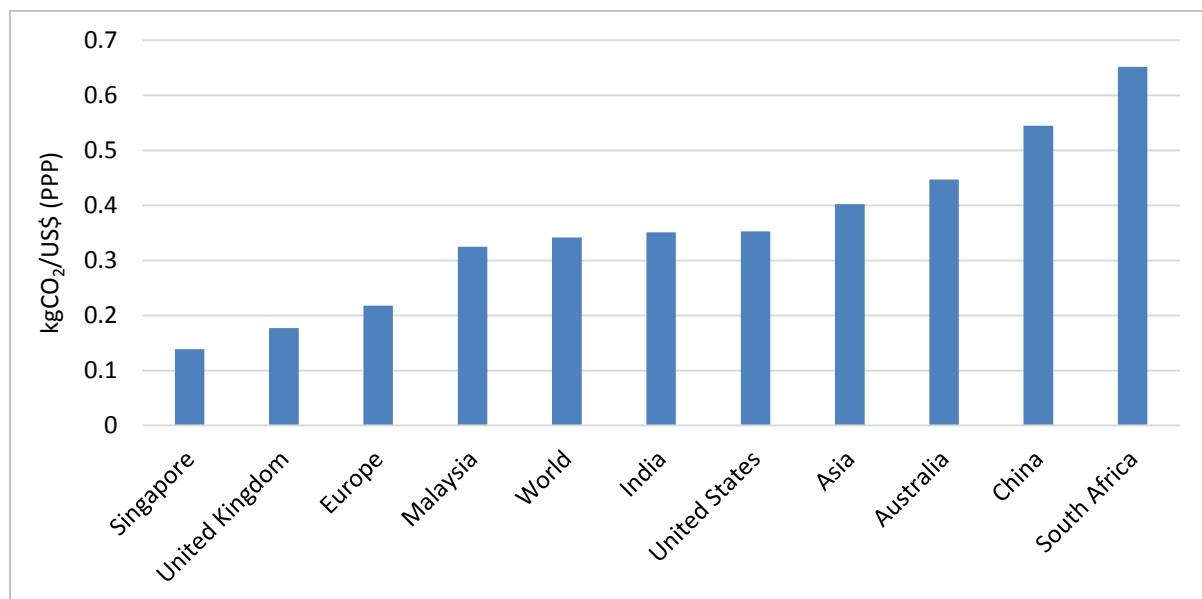


Figure 4: The CO₂ intensity of GDP for selected countries in 2014 (Enerdata, 2014a).

China, India, Malaysia and Singapore have stated climate change targets based on reductions in the emissions intensity of GDP (energy used per unit of gross domestic product (GDP) at purchasing power parity (PPP)) emission intensity which makes it an important parameter to quantify. Singapore has one of the lowest values of CO₂ per unit of GDP in the world due to its high GDP and small relative emissions. Malaysia's emission intensity is similar to the world average as seen in Figure 4. It can be observed that South Africa, China and Australia's energy intensity of GDP are well above the world average of 0.34kgCO₂/US\$ (Enerdata, 2014a).

The CO₂ intensity of electricity production is an indicator that is particularly relevant to this report and is shown in Figure 5. India has the highest CO₂ intensity of electricity production in the world at 964gCO₂/kWh (Enerdata, 2014a). South Africa, Australia and China also have very high values of CO₂ intensity of electricity production that are above the world average of 513gCO₂/kWh. This is predominantly due to the large dependence on carbon intensive coal fired power stations in these countries. Malaysia's CO₂ intensity of electricity production of 651gCO₂/kWh is above the world average due to an increasing percentage of coal fired generation and inefficiencies in the electricity infrastructure (Enerdata, 2014a). Singapore's CO₂ intensity of electricity production is fairly low as its generation is predominantly natural gas based and there are strong energy efficiency measures in place within the electricity system.

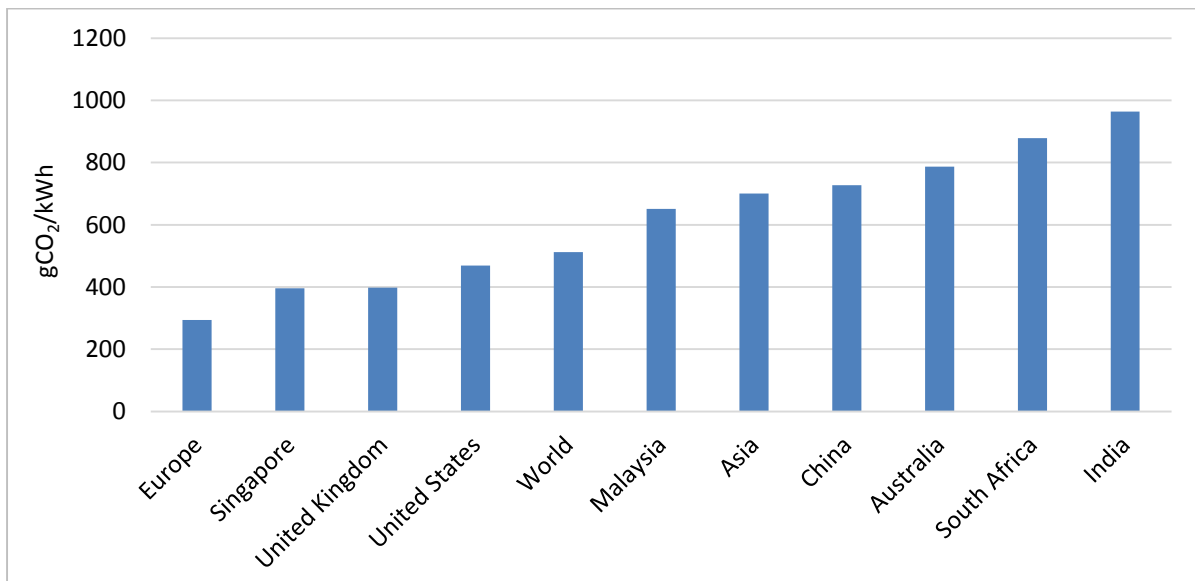


Figure 5: The CO₂ intensity of electricity production in selected countries in 2014 (Enerdata, 2014a).

4 AUSTRALIA

Highlights

- Australia is the fourth-largest coal reserve holder globally. It is set to become the world's largest exporter of LNG in 2020. Its crude oil reserves are limited, and net oil imports are expected to increase 129% by 2050. Australia has large renewable energy resources, with theoretical renewable energy generation capacity is 500 times larger than electricity demand.
- Australia exports approximately 80% of its total primary energy resources. Ensuring its energy industry remains internationally competitive and attractive for investment is one of the key drivers shaping Australia's energy domestic energy policy.
- In an effort to reduce the cost of energy to households and industry, Australia repealed key parts of its Clean Energy Act in 2014, including its carbon tax and plans to establish a nation-wide emission trading scheme.
- Australia pledged to reduce GHG emissions 5% by 2020 below 2000 levels. The government estimates this translates into a total emission level of 530 MtCO_{2e} by 2020. The power sector accounts for 34% of GHG emissions, and is the main driver for emissions growth.
- The removal of the carbon tax has made coal-fired generation cheaper compared to gas-fired generation and renewable energy sources. Coal-fired generation is now expected to supply 65% of generation by 2050. CCS is not expected to be deployed before 2050 due to high costs.

4.1 Background

Australia is a federal parliamentary democracy composed of six states and two territories. The Federal Australian Government is located in the nation's capital Canberra, which lies in the Australian Capital Territory (CIA, 2015a). In 2014, Australia's population was 23.49 million, with a high urbanisation level of 89% (WB, 2015a). The majority of Australia's population lives along the eastern and south-eastern coast, in the states Victoria, New South Wales, and Queensland (APERC, 2013a).

The World Bank classifies Australia as a high-income country, with a GDP per capita of US\$ 67,463 in 2013 (WB, 2015a; IMF, 2015). Australia's service sector accounts for approximately 70% of GDP (CIA, 2015a). Due to vast energy reserves and resources, Australia is a large exporter of coal, gas, and uranium (IDDRI & SDSN, 2014). It exports approximately 80% of its total primary energy resources (Carson, 2014). Australia expects its energy exports to increase as Asian markets continue to expand (Carson, 2014). The government is encouraging investment in the energy sector to satisfy this growing demand and increase export earnings (EIA, 2014a).

Since 2000, Australia's primary energy demand has increased at an average annual rate of 1.4% (Enerdata, 2015a). The transport sector is the largest consumer of energy, accounting for 38% of final consumption in 2014 (Enerdata, 2015a). Due to its size and relatively low population density, road transport is a key enabler to economic growth (APERC, 2013a).

Industry is the second largest energy consumer, accounting for 31% of consumption, followed by the service and residential sector with 25% (Enerdata, 2015a).

4.1.1 Emissions

According to the National Greenhouse Gas Inventory, Australia's total GHG emissions (excluding LULUCF) was 533.9 MtCO₂e in the year leading up to March 2015 (Department of the Environment, 2015a). This is an increase of 24.7% above 1990 levels. Figure 6 depicts Australia's GHG emissions by sector. From 1990 to 2015, emissions from the electricity sector, transport sector, and industrial sector grew by 39.6%, 50.7% and 18.1% respectively (Department of the Environment, 2015a). Process and fugitive emissions from Australia's mining and manufacturing sector rose by 13.2%. This has been offset slightly by a decrease in emissions from the waste and agricultural sectors, with emissions decreasing by 35.7% and 5.0% respectively (Department of the Environment, 2015a).

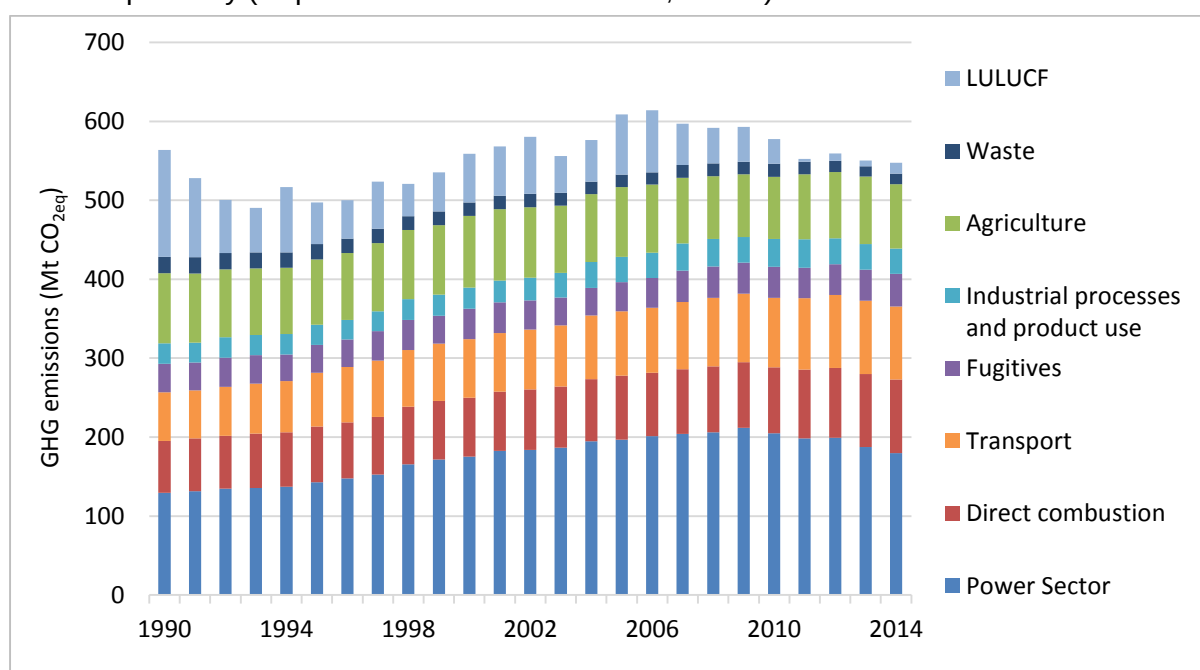


Figure 6: Australia's GHG emissions by sector, 2005-2015 (Department of the Environment, 2015a).

In 2014, energy-related CO₂ emissions accounted for 67% of Australia's total GHG emissions, while emissions from agriculture, and processes and fugitive emissions accounted for 15% and 13% respectively (IDDRI & SDSN, 2014). As outlined in Chapter 2, Australia has a relatively high per capita emissions rate. This reflects the importance of energy-related industries in the economy, the dominance of coal in the power sector, as well as the dependence on long-distance road transport (IDDRI & SDSN, 2014).

As shown in Figure 6 the power sector was the largest contributor of emissions in 2014, accounting for 33% of total GHG emissions and more than 50% of total energy-related CO₂ emissions (Enerdata, 2014a; Department of the Environment, 2015b). The manufacturing

industry and construction sector is the largest consumer of electricity (Department of the Environment, 2015a).

4.1.2 Climate Change Targets

At the 2009 climate change negotiations in Copenhagen, Australia pledged to reduce GHG emissions 5% below 2000 levels by 2020. This corresponds to a 13% reduction below 2005 levels (DFAT, 2015). This translates into an emissions target of 533 MtCO₂e in 2020 (DPMC, 2015). Australia stated that it will increase its pledge to 15% or 25% below 2000 levels by 2020, depending on global action on climate change mitigation (Cantzler et al., 2015).

In August 2015, Australia released its INDC in preparation for COP-21 in Paris. The country pledged to reduce greenhouse gas emissions by 26 to 28 per cent by 2030 compared to 2005 levels (UNFCCC, 2015c). This pledge is approximately equivalent to a 19% reduction below 2000 levels (The Climate Institute, 2015). This translates into an emissions level of 441-453 MtCO₂e by 2030 (DPMC, 2015). The government expects emissions per unit of GDP to decrease by 64%, and per capita emissions to fall by 50% to 52% from 2005 to 2030 (DPMC, 2015). The INDC outlines that Australia may adjust the target in response to an agreement reached at COP-21 (UNFCCC, 2015c). There is thus uncertainty regarding what Australia will actually do to contribute to global emission level reductions (Cantzler et al., 2015). An overview of Australia's climate change targets is provided in Table 2.

Table 2: Australia's Climate Change Targets

	2020	2030
Greenhouse gas emissions	Reduce by 5% below 2000 levels (equivalent to 13% below 2005 levels) Target: 533 MtCO ₂ e	Reduce by 26-28% below 2005 levels Target: 441-453 MtCO ₂ e
GHG emissions per unit of GDP	-	64-65% reduction below 2005 levels
GHG emissions per capita	-	50-52% reduction below 2005 levels

4.2 Australia's Electricity System

4.2.1 Electricity Market

There are five main electricity networks in Australia, and several smaller systems in remote locations across the country (Carson, 2014). This is displayed in Figure 7. The National Energy Market (NEM) is the largest and connects five states along the eastern and south-eastern coast (New South Wales, Victoria, South Australia, Tasmania, and Queensland) and the Australian Capital Territory (EIA, 2014a). The NEM accounted for 85% of Australia's total electricity consumption in 2013 (BREE, 2014). There are two distinct systems in Western Australia: the South West Interconnected System (SWIS) and the North West Interconnected System (NWIS). The Darwin-Katherine and Alice Springs systems operate in the Northern

Territory (Carson, 2014). In 2013, Western Australia and the Northern Territory accounted for 12% and 0.01% of electricity consumption respectively (BREE, 2014).

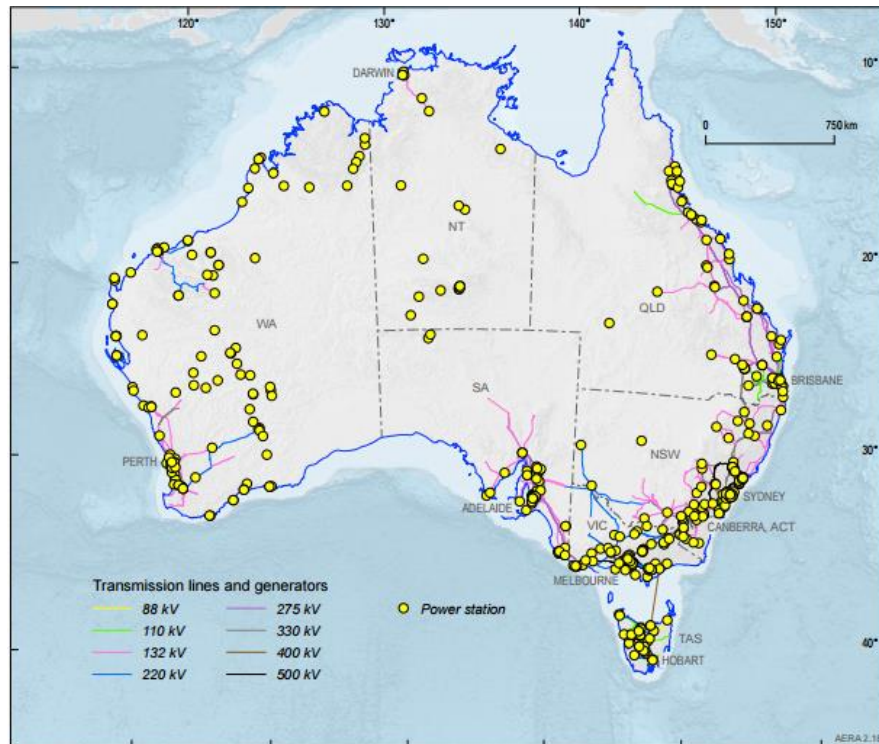


Figure 7: Australia's electricity systems (Carson, 2014).

The NEM and SWIS both have wholesale markets to manage the trade of electricity. They function as a 'pool', or spot market, in which generators submit bids to supply electricity, and the market operator determines the optimal operational schedule. A market price cap and price floor are outlined in the National Electricity Rules (AEMO, 2015). The NEM is managed by the Australian Energy Market Operator (AEMO). Approximately 50 production companies bid to sell their generation into the market (Enerdata, 2015a). The SWIS market, called the Wholesale Electricity Market (WEM) is operated by the Independent Market Operator (IMO) (Carson, 2014). Each state has its own electricity regulator, and wholesale electricity prices and residential electricity prices vary by state to reflect different environmental policy costs and market costs (Enerdata, 2015a). Interstate connection is managed by a national regulator called the Australian Energy Regulator (AER) (Enerdata, 2015a).

Electricity consumption in Australia grew 2.4% on average annually from 2000-2007, due to growth in the mining sector and other energy-related industries (Enerdata, 2015a; EIA, 2014a). Since 2010, however, electricity consumption has declined. This is due to rising electricity prices, policy measures promoting energy efficiency, and milder meteorological conditions (BREE, 2014). The manufacturing industry has seen the largest decrease in electricity demand, which saw an average annual decline of 3% from 2010 to 2013 (BREE, 2014). In 2014, Australia's electricity per capita was 9,395 kWh/capita, which is higher than the OECD average of 7,480 kWh/capita (Enerdata, 2014a).

4.2.2 Energy Resources and Trade

Fossil Fuels

In 2013, coal accounted for 35% of primary energy consumption. The electricity sector is the largest consumer of coal, accounting for 93% of domestic coal consumption (Enerdata, 2015a). Australia's coal consumption has been declining since 2009 due to inter-fuel substitution between coal and gas in the power sector (EIA, 2014a).

Australia is the fourth largest coal reserve holder in the world, accounting for approximately 8.6% of the global total (BP, 2015). The Australian Bureau of Resources and Energy Economics (BREE) estimates that 105,246 Mt of its coal reserve are economically exploitable (Carson, 2014). As Table 3 shows, Australia's theoretical potential is larger, due to large sub-economic resources and inferred potential. Changes in global coal demand, prices, and increased resource development could increase the commercial viability of these reserves. These large reserves have allowed Australia to become the fifth largest coal producer globally. It exports approximately 73% of coal production (Enerdata, 2015a). On a weight-basis, Australia was the world's largest exporter of coal until 2011, when Indonesia surpassed it. In terms of revenue, black coal exports were Australia's second largest export commodity in 2012 (EIA, 2014a). With a black coal reserves-to-production ratio (R/P) of 110 years, and a brown coal R/P of 510 years, Australia is unlikely to stop exploiting its coal reserves unless incentivised to do so (Carson, 2014).

Table 3: Australia's Fossil Fuel Resources, 2012 (Adapted from Carson, 2014; BP, 2015).

Resource	Unit	Economic Demonstrated Resources	Sub-Economic Resources	Inferred Potential	Total	Share world total (%)	R/P
Coal	Mt	105246	53705	166686	325637	8.6	
Black coal	Mt	61082	5118	64184	130384		110
Brown coal	Mt	44164	48587	102502	195253		510
Gas	tcf	132	117		249	2.0	
Conventional	tcf	99	57		156		51
Coal seam	tcf	33	60		93		150
Oil	mmbbl	3779	1537		19704	0.2	
Condensate	mmbbl	1917	799		2716		26
Crude oil	mmbbl	930	325		1255		9
LPG	mmbbl	932	413		1345		16
Shale oil	mmbbl				14388		

Natural gas accounted for 24% of primary energy consumption in 2013 (Enerdata, 2014a). Approximately 38% of natural gas consumption is for electricity generation. The second largest consumer is industry (26%) followed by the energy sector (22%) (Enerdata, 2015a). From 2007 to 2014, natural gas consumption in Australia saw an average annual rise of 6.1%, in part due to an increase in natural gas-fired generation (Enerdata, 2015a).

Australia's proven gas reserves are the largest in the Asia-Pacific region (Enerdata, 2015a). Approximately 90% of the country's proven reserves are located off the western shore (Enerdata, 2015a). This is displayed in Figure 8. The majority of Australia's gas reserves is conventional gas (99 tcf of economic demonstrated resources), but proved coal-bed methane resources have doubled in the past three years due to increased exploration and investment in gas reserves (EIA, 2014a). Technically recoverable shale gas reserves were approximately 437 Tcf in 2012 (EIA, 2014a).

Australia's natural gas production has increased by more than 50% since 2005, with large investments in liquid natural gas (LNG) projects (Enerdata, 2015a). Three LNG export facilities are in operation in Australia, and it is the third-largest LNG exporter in the world (EIA, 2014a). As of August 2015, seven LNG export facilities are under construction, and Australia is likely to become the world's largest LNG exporter in 2020 (EIA, 2014a).

The country's crude oil reserves are limited, with an R/P ratio of 9 years (Carson, 2014). The nation is dependent on imports to satiate oil demand (EIA, 2014a). Due to the nation's limited oil reserves, domestic oil production is expected to decline by up to 80% by 2050. Demand for oil, however, is expected to increase towards 2050 as the transport sector continues to grow. As a result, net imports are expected to increase by 129% by 2050 (Enerdata, 2015a).

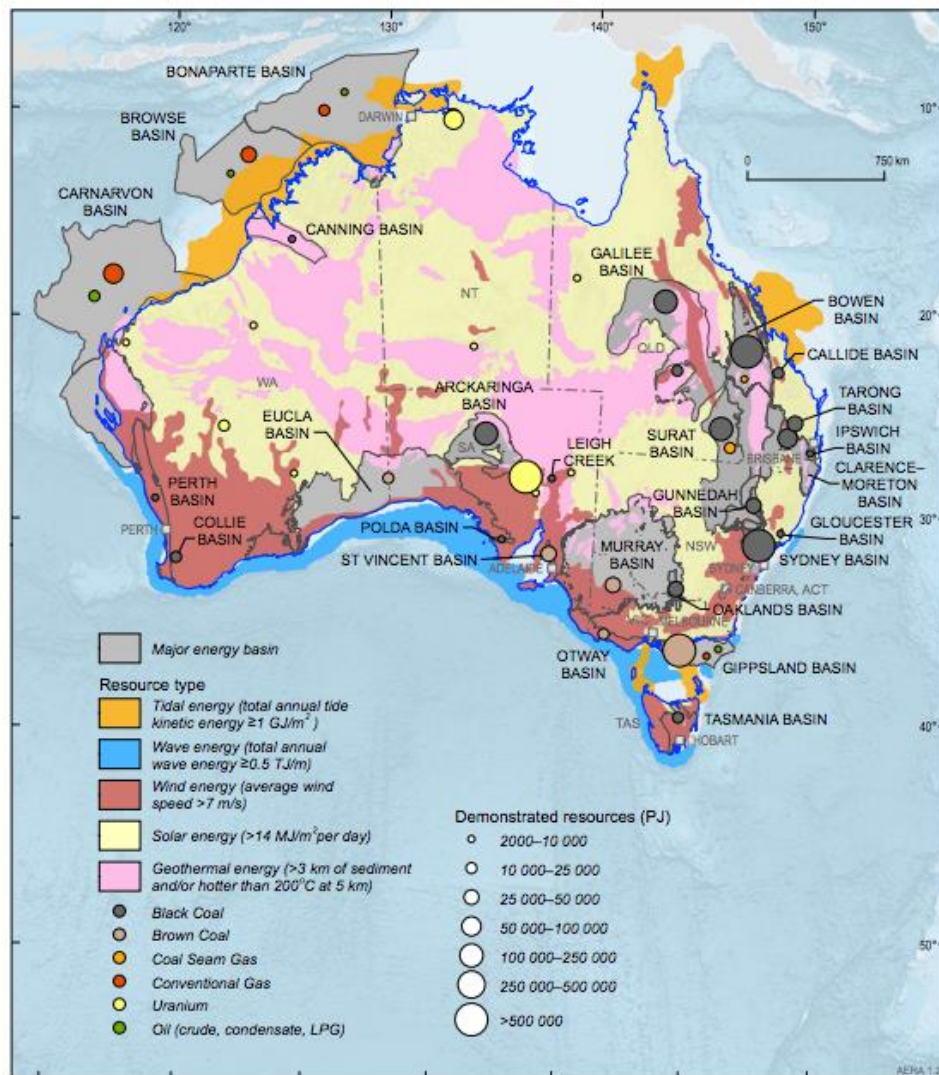


Figure 8: Australia's major energy resources, excluding hydropower and bioenergy (Carson, 2014).

Renewable Energy Sources and Hydropower

As Australia has large renewable energy potential, as shown in Table 4. As depicted in Figure 8, the southern coast has good wave energy potential, while the northern coastline is suitable for tidal energy (Carson, 2014). The BREE estimates that wave energy generation along the southern shore has the potential to satisfy up to 10 percent of national electricity demand by 2050 (Carson, 2014). A key constraint is that areas of high wave energy potential are removed from population and energy demand centres, which are located along the eastern coast.

Table 4: Australia's Renewable Energy Resource Potential (including hydropower) (AEMO, 2013)

Resource	Maximum installable generation capacity (GW)	Maximum recoverable electricity (TWh/yr)
Hydropower	8	12
Biomass	16	108
Solar	18500 – 24100	41600 – 71700
Wind	1540	6200
On-shore	880	3100
Off-shore	660	3100
Wave	133	275
Geothermal	5500	38570
Enhanced Geothermal Systems	5140	36040
Hot Sedimentary Aquifers	360	2530
Total Potential	25,700 – 31,300	86,800 – 116,900

Large-scale solar power faces the same constraint, as the northwest and centre of the continent have the highest levels of solar radiation. The Australian continent as a whole has the highest solar radiation per square metre globally, exceeding domestic energy consumption by a factor of 10,000 (Carson, 2014). Although the lack of grid infrastructure inhibits the full exploitation of Australia's solar potential, the BREE estimates that the solar energy resources available within 25km of existing transmission infrastructure is 2.7 million PJ, which exceeds national annual energy consumption by a factor of 500 (Carson, 2014). Australia also has good wind resources, located inland, and in the south-western, southern and south-eastern parts of the continent (Carson, 2014).

Australia has a low annual average rainfall, with half of the continent receiving less than 300 mm per year. This limits Australia's hydroelectric potential (Carson, 2014). The country's geothermal resource is not adequately quantified, but there is interest in hot rock geothermal resources and lower temperature geothermal resources to provide baseload capacity in the future (Carson, 2014). Three geothermal demonstration projects are currently under development to explore the commercial viability of the resource and to test different technologies.

4.3 Energy Policy and Drivers

Energy-related industries are integral to the Australian economy. These industries create employment and support other industries, directly contributing 5% of industry gross value added in the year from 2011 to 2012 (Carson, 2014). The energy-industry also raises considerable export revenues, accounting for 24% of total export value in 2011-12 (Carson,

2014). By 2020, Australia expects annual energy-related export earnings to reach AUD 114 billion as the demand for its energy resources grows (DIS, 2015).

Australia's international competitiveness in the energy market is due to a stable policy environment, relatively low energy prices, and large fossil fuel reserves (EIA, 2014a). Australia's energy prices have been rising, however, with electricity prices for industry and the residential sector increasing more than 100% from 2007 to 2014 (Enerdata, 2015a). Rising prices, as well as labour shortages, stricter environmental regulation, and the rising cost of energy-related projects in general have placed constraints on the Australian energy industry in recent years (EIA, 2014a).

The 2015 Energy White Paper provides the framework for the Australian Federal Government's energy policy. It stresses the need to reduce prices in the electricity sector and the energy-industry in order to remain competitive on international markets (DIS, 2015). This is seen as an essential component of enabling economic growth. The Energy White Paper identifies three main pillars to support this objective:

1. Increase competition in the market in order to reduce prices to households and business;
2. Use energy more productively to decrease costs, increase the efficient use of energy, and promote economic growth;
3. Encourage investment to increase employment and exports through innovation and the development of energy resource exploitation (DIS, 2015).

Table 5 provides a brief overview of Australia's key energy policies. The following sections outline how these policy objectives have affected the electricity sector.

Table 5: Australia's Key Energy Policies

Date	Policy	Details
2011 Update in 2015	Renewable Energy Target	Generate 33,000 GWh of electricity from renewable energy sources by 2020 Increase renewable energy share in electricity generation mix to 20%
2014	Emission Reduction Fund	Auction through which emitters are paid to implement abatement measures
2015	Energy White Paper (2015)	Outlines national energy policy Aims to: 1. Increase competition by decreasing prices 2. Promote growth by increasing energy productivity 3. Stimulate investment
Proposed	National Energy Productivity Plan	Improve national energy productivity by 40% by 2030

Increase Competition

The 2015 Energy White Paper states that competition is the most effective way to reduce costs (DIS, 2015). To this end, the Paper outlines the need to reduce government intervention

and privatise state-owned generation capacity (DIS, 2015). Government intervention is viewed as harmful as it prevents the market from operating freely. Policies such as feed-in-tariffs that make renewable energy technologies more competitive, for example, ‘can distort market signals and cause unintended disruptions to competitive energy markets’ (DIS, 2015). Although the Department of Industry (DIS) states that the largest factor causing the rise in electricity prices in recent years were to recover transmission investment costs, these are seen as necessary to improve electricity supply to consumers (DIS, 2015). By contrast, environmental policies were stated to have imposed an extra cost on consumers (DIS, 2015).

In 2014, the Australian government repealed key parts of its Clean Energy Act. The carbon tax was abolished to reduce costs to households and businesses, and plans to establish a national carbon emission trading scheme (ETS) were abandoned (Department of the Environment, 2015e). The Department of the Environment estimates that repealing the tax will lower the average cost of living of households in 2014 to 2015 by AUD 550 (approximately US\$ 384) (Department of the Environment, 2015e). While feed-in-tariffs are set by state-level governments, the Federal Government outlines the need to reduce feed-in-tariffs (FiT) as the cost of photovoltaic (PV) has dropped in recent years. FiTs to households with PV installations are seen as high and subsidised by consumers without solar (DIS, 2015). All states except Queensland and Western Australia have a FiT, although they vary in the rate set (Climate Council, 2014).

Increase Energy Productivity

Several energy efficiency programs were ended between 2013 and 2014 in line with the policy of reducing government intervention and reducing costs for industry and households (Enerdata, 2015a). The government has stated that it is going to focus on improving national energy productivity in order to reduce costs. The government defines national energy productivity as the ratio of real GDP to primary energy consumption. The Federal Government is developing a National Energy Productivity Plan, with a possible target of improving national energy productivity up to 40 percent between 2015 and 2030 (UNFCCC, 2015c). In the electricity sector, the government is promoting measures to incentivise consumers to reduce demand during peak hours. This includes providing different tariffs during different times of the day, and promoting the use of smart metres (DIS, 2015).

Encourage Investment

The Australian government is investing in Carbon Capture and Storage (CCS) technologies as it expects coal-fired power plants to continue supplying a large share of electricity supply in the future (DIS, 2015). CCS is also expected to reduce emissions in other energy-related fields, such as Australia’s LNG sector and coal mining. For example, Chevron is installing CCS equipment at its Gorgon LNG project, which will be the largest storage project worldwide once it becomes operational in 2016 (DIS, 2015/Enerdata, 2015a). The Australian Coal Association formed the COAL21 Partnership in order to reduce emissions from the coal sector (DIS, 2015).

The Partnership established the COAL21 Fund, which is investing AUD 300 million (approximately US\$ 310 million) in CCS demonstration projects (DIS, 2015).

In 2000, the Federal government launched the Renewable Energy Target (RET) scheme to encourage investment in renewable energy. The RET aims to increase the share of renewable energy sources to 20% in 2020 (Department of the Environment, 2015d). It is divided into two streams: the Large-Scale Renewable Energy Target (LRET) and the Small-Scale Renewable Energy Target (SRES). The LRET issues Large-Scale Generation Certificates (LGCs), which represent one megawatt hour (MWh) of renewable energy generation. Power stations then sell these LGCs to electricity retailers to earn revenue (Department of the Environment, 2015d). The SRES works in a similar manner, issuing Small-scale Technology Certificates (STCs) for expected future generation from small-scale renewable energy systems (Department of the Environment, 2015d). The government reviewed the RET in 2015 and reduced the target of power generation from renewable energy sources from 41,000 GWh to 33,000 GWh in 2020 in order to reduce costs. While the LRET was previously expected to be extended past the original scheme length, the changing policy climate makes it likely that it will be terminated in 2030 (AEMO, 2014).

Reduce Emissions

Reducing emissions in order to mitigate climate change is not one of the key objectives outlined in the 2015 Energy White Paper. However, at COP-15 in Copenhagen, Australia committed to reducing greenhouse gas emissions 5% below 2000 levels by 2020. Thus, when the Federal Government repealed the Clean Energy Act, it proposed to reach the target through measures outlined in its Direct Action Plan (Cantzler et al., 2015).

The Emissions Reduction Fund (ERF) lies at the heart of the Direct Action Plan. Through the ERF, businesses bid to receive funding to implement emission abatement measures. Thus emitters with the least-cost abatement opportunities are paid to reduce emissions (Enerdata, 2015a). The first auction was in April 2015, through which 47 Mt of emissions abatement was bought by the ERF (UNFCCC, 2015c). The government intends to introduce safeguard mechanisms in 2016 to ensure that reductions through the ERF are not offset by increases in emissions in other sectors of the economy (UNFCCC, 2015c). This will be done by ensuring Australia's largest emitters remain within quantified baseline emission levels. The safeguard mechanism will include electricity generators with emissions above 100,000 tCO₂-e, and will be set according to the highest point of emissions in the sector between 2009 and 2014 (Department of the Environment, 2015c). According to the government, the Emission Reduction Fund is expected to result in a 360 MtCO₂e reduction in emissions by 2030 (Cantzler et al., 2015). It is unclear how much of this reduction will come from abatement measures in the electricity sector.

Federal Government policy changes influence state-level legislation. Victoria, Queensland, Western Australia, New South Wales and the Northern Territory abandoned their state-level

greenhouse gas reduction targets with the introduction of the nation-wide RET scheme and emission reduction targets (Climate Council, 2014). Tasmania removed its interim 2020 target, but has maintained its 2050 target to reduce GHG emissions by 60% below 1990 levels, as this has been codified into law.

South Australia and the Australian Capital Territory still have separate targets from the Federal Government. South Australia has a 60% reduction target by 2050, and aims to generate 33% of its electricity from renewable energy sources by 2020, rising to 50% by 2025 (Climate Council, 2014). Climate Council (2014) estimates that South Australia will exceed this goal based on its current rate of renewable energy capacity instalments. The Australian Capital Territory has a target to reduce emissions 80% below 1990 levels by 2050. This includes a target to generate 90% of its electricity from renewable energy sources by 2020 (Climate Council, 2014). To encourage renewable energy projects at a regional level, electricity generated through national RET scheme does not count towards the ACT target.

4.4 Current Generation Capacity

In 2014, Australia's total installed capacity was 67.5 GW (Enerdata, 2014a). There is currently an overcapacity in the NEM, and AEMO does not expect new generation capacity to be necessary until 2024 (AEMO, 2014). As Figure 9 shows, coal has historically been the dominant fuel source in the electricity sector. This is because Australia's coal reserves are mostly located near the largest electricity demand centres on the continent's eastern coast, and so coal has provided an easily accessible and relatively cheap source of fuel (Carson, 2014). In 2014, 23 coal-fired power plants were in operation with a combined installed generation capacity of 29.4 GW, corresponding to 43.6% of total installed capacity (Enerdata, 2014a). Of these, four are supercritical power stations with a combined capacity of 2.9 GW. The remaining power plants use subcritical technology.

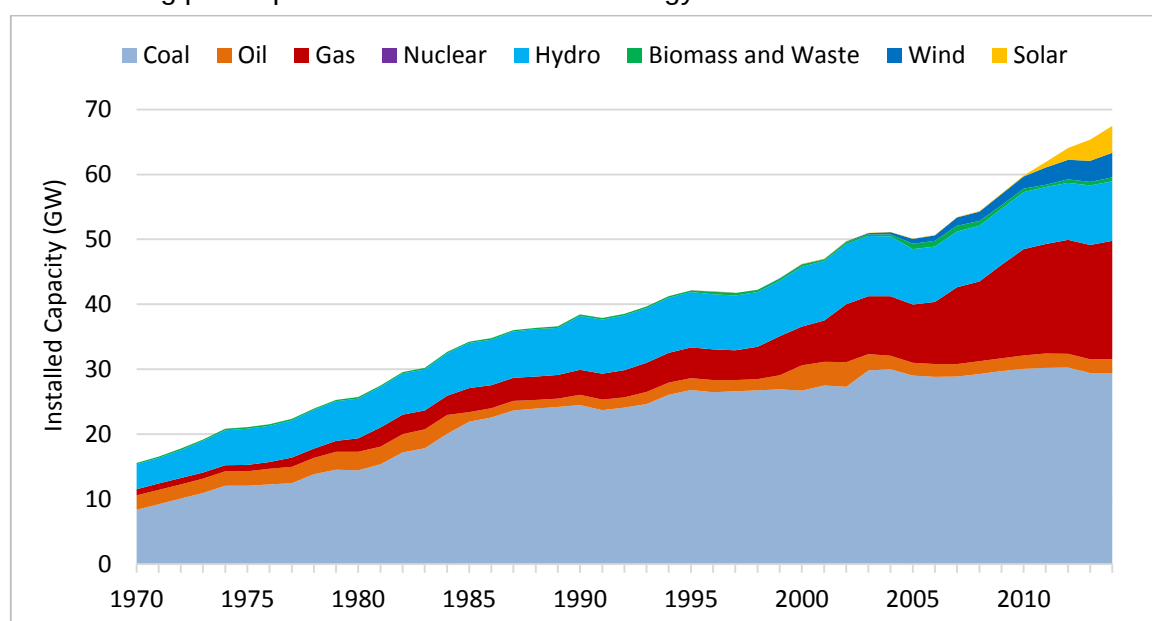


Figure 9: Australia electricity capacity by fuel, 1971-2014 (Enerdata, 2015b).

Figure 9 shows the growth of gas-fired installed capacity since 2000. Gas-fired generation capacity expanded with an average increase of 15%/year from 2000-2013 (Enerdata, 2015a). A key factor influencing the growth in installed capacity since 2012 was the introduction of the carbon tax, which made gas-fired generation more commercially competitive to coal-fired generation. In 2014, gas-fired power stations represented 27% of total installed capacity, with 18 GW of capacity (Enerdata, 2014a). As the tax was repealed in 2014, it is possible that the share of gas-fired generation will decline.

As shown in Figure 10, the share of fossil fuels in electricity generation is larger than the share of installed capacity. This is due to the role of coal-fired capacity as a baseload provider. In 2014, coal-fired generation accounted for 63.6% of electricity generation. Natural gas-fired generation is primarily used to address peak power, and accounted for 22.4% of the total 252.6 TWh produced (Enerdata, 2014a).

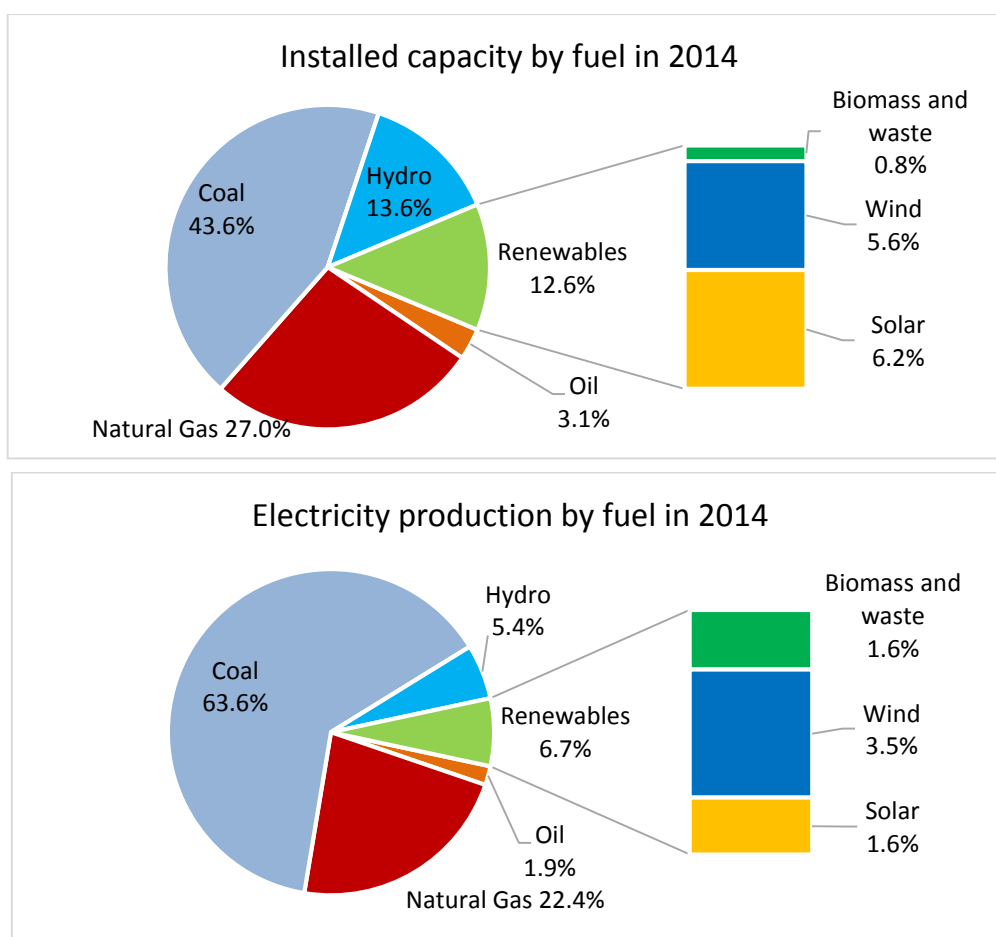


Figure 10: Comparison of installed capacity and electricity production in Australia for 2014 (Enerdata, 2014b).

In 2014, 108 hydroelectric power stations with a total installed capacity of 7.8 GW were in operation in Australia (BREE, 2014). The majority of Australia's hydroelectricity is located in two states, with 60.5% of installed capacity located in Tasmania, and 26.9% in New South

Wales (BREE, 2014). Generation from hydropower has remained relatively stable since the 1980s, and is unlikely to grow further due to water constraints.

The share of renewable energy sources in total generation capacity has increased from 4.3% in 2010 to 12.6% in 2014. Wind energy is Australia's fastest growing power generation source, with 3.8 GW of onshore wind capacity installed in 2014 (Carson, 2014). Solar PV represents the largest share of renewable energy generation, with 4.2 GW of installed capacity and accounting for 6.2% of total generation (Enerdata, 2014a). Less than 1% of installed capacity is from biomass sources, mostly from by-products of sugar production and waste streams such as landfill and sewage sites (Carson, 2014). The share of renewable energy sources in electricity generation rose from 3.5% in 2010 to 6.6% in 2014 (Enerdata, 2015a). This rise is in part due to policy measures such as the carbon tax and stricter environmental regulation that incentivised investment in renewable energy sources.

Although Australia has significant uranium resources, no nuclear power stations were in operation in 2015. The Environment Protection and Biodiversity Conservation Act 1999 and the Australian Radiation Protection and Nuclear Safety Act 1998 inhibit the construction and operation of nuclear power plants (DIS, 2015).

Emission Intensity of Electricity

Due to the reliance on coal in power generation, emission intensity of Australia's electricity generation is relatively high. In 2014, Australia emitted 787.3 gCO₂/kWh which is almost double the OECD average of 398.98 gCO₂/kWh. It is also above that of China (727 gCO₂/kWh) and the global average (512.6 gCO₂/kWh) (Enerdata, 2014a). The emission intensity of the electricity sector fell from 2009 to 2013 (Enerdata, 2014a). This is in part due to the increase of gas-fired generation and generation from renewable energy sources. The reduction in emission intensity combined with a decline in electricity consumption caused total sectorial emissions to fall in 2013 and 2014, as depicted in Figure 11.

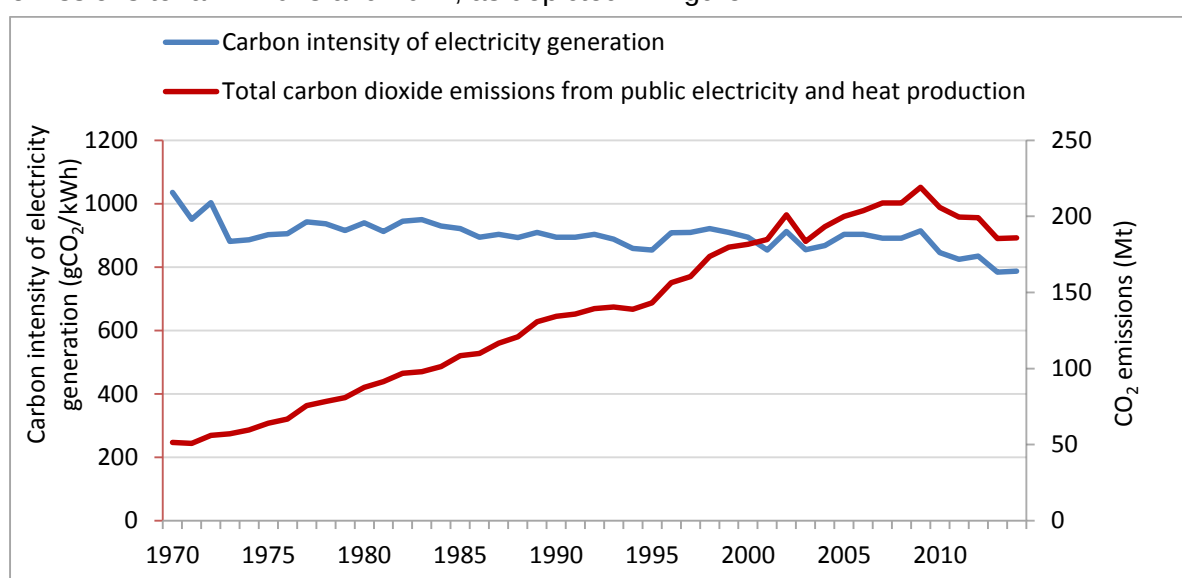


Figure 11: Australia's total CO₂ emissions and carbon intensity of electricity generation, 1975-2014 (Enerdata, 2015f).

This reduction seems to be reversing, however, as the emission intensity of electricity generation increased over the year to March 2015. This is in part due to an increase in generation from fossil fuel resources, and an overall decrease in generation from low-carbon sources from 2014 to 2015. Generation from intermittent renewable energy sources increased by 12.1%, but generation from hydropower decreased by 26.9% over the same time period due to low levels of rainfall. Consequently, electricity sector emissions increased by 0.7%. Over the year to June 2015, the NEM's annual emissions are expected to increase 4% (Department of the Environment, 2015a). It is likely that Australia's electricity generation emission intensity will continue to increase as the share of coal-fired generation rises towards 2035. This will be discussed in the following section.

4.5 Discussion and Analysis

In 2014, the power sector accounted for 34% of GHG emissions and more than half of energy-related CO₂ emissions (DIS, 2015; Enerdata, 2015a). The government indicates that electricity generation is the main driver for emissions growth. Developments in the electricity sector significantly influence Australia's ability to reach its climate change targets. The following section examines what the government expects electricity demand and generation to be towards 2050, and subsequent emission levels in the power sector. Scenarios developed by the Asia-Pacific Economic Cooperation will then be analysed to determine whether there are any discrepancies between projections.

4.5.1 Government Projections

The demand for electricity is expected to grow towards 2050. This is mainly due to the expansion of Australia's LNG exports. New coal seam gas projects as well as upstream processing for LNG projects are expected to become operational towards 2018, requiring electricity to fuel the industry. Electricity demand growth from these industries is then expected to plateau, but not necessarily decline (Department of the Environment, 2015a). After 2018, however, economic activity is expected to rise, as well as the demand for electricity from general businesses (Department of the Environment, 2015a). Additionally, household income is expected to increase faster than electricity prices, and so the household demand for electricity is also expected to rise until 2035 (Department of the Environment, 2015a).

Electricity generation in Australia is expected to increase from 255 TWh in 2014 to 315 TWh by 2035, and 332 TWh by 2050 under BaU (Syed, 2014). Apart from the target outlined in RET to increase the share of renewable energy (including hydro) in electricity generation to 20% by 2020, Australia does not have generation or installed capacity targets. This differs from electricity policy in China, as will be outlined in Chapter 5. As the NEM and WEM operate as markets, investment and participation decisions are based on incentives and not on regulations regarding the amount of capacity that should be installed from each source. This supports the government's commitment to taking a technology-neutral approach to ensure markets operate freely (DIS, 2015). As shown in Figure 12, the share of renewable energy

generation (including hydropower) is expected to increase from 12% in 2014 to 20% in 2050. The share of fossil fuel generation is expected to decrease slightly from 85% to 80% (Syed, 2014). This will now be examined in detail.

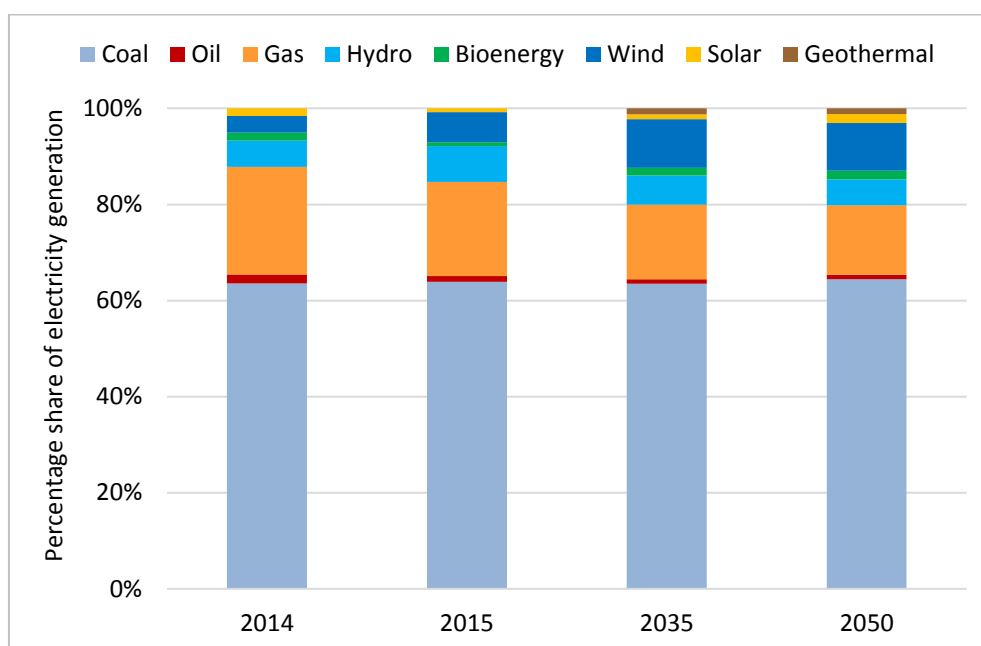


Figure 12: Australia's electricity generation under BaU Scenarios, 2014-2050 (Syed, 2014).

Coal-Fired Generation Capacity

Approximately three-quarters of coal-fired power plants are operating beyond their design life and are less efficient than current best-available technologies (DIS, 2015). The government has indicated that it will not implement policies to encourage inefficient generation capacity out of the market, as this distorts market incentives and increases costs to households and industry (DIS, 2015). This increases the carbon intensity of generation.

Australia's changing policy climate, particularly the decision to repeal the Clean Energy Act, has influenced the generation mix by increasing the projected share of coal-fired generation (Syed, 2014). In 2012, the BREE projected that the carbon tax would incentivise investment in low-carbon generation (Syed, 2012). Coal-fired generation was expected to decrease 2.2% annually, declining from 60% in 2012 to 13% in 2050 (Syed, 2012). Furthermore, CCS was expected to be used by the mid-2030s, reaching 23% by 2050, as the carbon tax increased its commercial viability (Syed, 2012). The government's updated projections consider the removal of the carbon tax and other environmental policies. The share of coal-fired generation is expected to increase to 65% in 2050 (Syed, 2014). This is because the removal of the carbon tax makes coal-fired generation cheaper compared to gas-fired generation and renewable energy sources (EIA, 2014a). The BREE also does not expect CCS to be deployed towards 2050 due to the technology's high costs (Syed, 2014). Thus, as coal-fired generation without CCS is expected to provide the majority of electricity supply, emission levels from the power sector are likely to increase.

According to approved generation projects in 2015, approximately 2.6 GW of black coal-fired capacity is expected to come online between 2014 and 2020. In 2014, two black coal-fired capacity were under construction and expected to add 416 MW of capacity to the grid between 2022 and 2024 (BREE, 2014). Three projects using integrated gasification combined cycle (IGCC) technology were under development (Enerdata, 2015a). Between 2017 and 2039, approximately 0.8 GW of brown-coal fired capacity is expected to retire (BREE, 2014). Thus, coal-fired capacity additions are expected to outweigh capacity retired by 2039. This seems to support government projections of an increase in coal-fired generation capacity.

Gas-Fired Generation Capacity

In 2012, BREE forecasted that the share gas-fired generation was going increase to 36% in 2050 (Syed, 2012). This was because gas-fired technologies were mature, and increasingly cost competitive due to the carbon tax (Syed, 2012). The repeal of the tax, however, has made coal-fired generation relatively cheaper (EIA, 2014a). Furthermore, domestic gas prices have risen since 2012, affecting the cost-competitiveness of gas-fired generation. Thus, inter-fuel substitution between gas and coal is likely. The BREE's latest forecasts, published in 2014, reflect these considerations. The share of gas-fired generation is now expected to decline from 19% in 2015 to 15% in 2050 (Syed, 2014).

In 2014, three gas-fired projects were under development. These are expected to come online between 2015 and 2018, increasing gas-fired capacity by 410-510 MW (BREE, 2014). Twenty other projects were at earlier stages of development, although they had not started construction. Between 2017 and 2039, 3.4 GW of natural gas generation capacity is expected to come offline in the NEM (AEMO, 2014). This translates into a 32% decrease in gas-fired capacity in the NEM by 2039, supporting BREE projections of a decline in gas-fired generation (AEMO, 2014).

Oil-Fired Generation Capacity

Government projections expect oil-fired generation to account for 1% in the electricity mix in 2050 (Syed, 2014). One oil project was at an early stage of development in 2014, with an estimated capacity of 150 MW to provide peak generation power. An estimated start-up date is not yet available (BREE, 2014). Given Australia's limited oil reserves, it is unlikely that oil-fired generation will play a large role in the power sector.

Nuclear Power Generation Capacity

Australia did not have any nuclear power projects under consideration in 2015. As noted above, the Environment Protection and Biodiversity Act 1999 and the Australian Radiation Protection and Nuclear Safety Act 1998 would have to be amended to allow for the construction and operation of nuclear energy. In the Energy White Paper 2015, the Australian government expressed interest in considering the opportunities and risk of nuclear energy in the future (DIS, 2015). As there is currently a surplus of capacity, and new generation is not

expected to be necessary until 2024, it is unlikely that nuclear energy will be developed in the near future as it is a baseload provider of electricity (Enerdata, 2015a).

Hydropower

Government projections expect hydropower generation to remain stable at 19 TWh from 2015 to 2035, decreasing to 18 TWh in 2050 (a 6% share of total generation) (Syed, 2014). One 40 MW hydropower plant is expected to come online in 2015 to address peak demand (BREE, 2014). As there is a lack of economically exploitable hydro capacity due to the scarcity of water in Australia, and approximately 56% of economically feasible hydropower is already being used (Carson, 2014). Although there are several large rivers in northern Australia that could be suitable for hydroelectric power generation, these are removed from infrastructure and demand centres. Thus, future growth in hydroelectric power is likely to come from energy efficiency improvements in current capacity, and the construction of small-scale plants (Carson, 2014). This is consistent with government projections of the limited role of hydropower in the future generation mix of Australia.

Renewable Energy Sources

The repeal of environmental legislation influenced projections regarding the share of renewable energy sources in the generation mix (Syed, 2014). The BREE forecasts in 2012 predicted a higher share of renewable energy generation towards 2050. Technology improvements, as well as policy measures such as the RET and carbon pricing mechanism were expected to cause reductions in the cost of renewable energy sources of electricity (Syed, 2012). By 2050, the share of renewables (including hydro) was expected to rise to 51% of generation, compared to 34% in 2012 (Syed, 2012). In large part due to the removal of the carbon pricing mechanism, the updated forecasts predict that the share of renewable generation rises to 20% in 2050 (Syed, 2014).

Investment in renewable energy declined by 70% from 2013 to 2014 due to uncertainty regarding the Federal Government's reform of its renewable energy policies (Flannery, Hueston & Stock, 2014). Furthermore, AEMO (2014) expects that no new renewable energy capacity will be added to the NEM after 2020 under current policy incentives. Thus, while renewable generation (including hydroelectricity) is expected to be 22% of the generation mix in 2020, the share of renewable generation declines towards 2050 (Syed, 2014). While this means the RET target (20% of renewable generation by 2020) is achieved, it is unlikely that it will be surpassed under current policy incentives.

The majority of Australia's future installed renewable energy capacity is expected to come from wind capacity. Australia has good wind potential, and wind energy is considered relatively cost competitive (Syed, 2014; BREE, 2014). In 2014, 77 wind power projects were at various stages of development, representing 47% of new capacity (AEMO, 2014; BREE, 2014). By 2020, 3.9 MW of wind capacity is expected to be completed (AEMO, 2014). Wind generation remains relatively stable after this as no new capacity is added.

Three solar projects were committed to be built in 2014 (BREE, 2014). One project, proposed by Silex Systems, suspended plans to construct 100 MW of solar power due to uncertainty regarding the changing RET scheme and low wholesale electricity prices (Enerdata, 2015d). By 2050, solar energy is expected to account for 2% of electricity generation (Syed, 2014). This is relatively small considering Australia's large solar power potential. This could be because the current policy climate provides incentives for technology that is more commercially competitive, such as wind power.

In 2014, two bioenergy projects were being developed, and expected to add between 120 and 125 MW of generation capacity to the grid by 2017 (BREE, 2014). Approximately 40 MW of this new capacity will be used to generate base-load power, while the remaining 80-85 MW will be built to address peak power needs (BREE, 2014). Although Australia's maximum recoverable electricity from biomass is large at 108 TWh/year, the growth of bioenergy is likely to be restrained by production factors such as water constraints (Syed, 2014; Carson, 2014). Thus, the share of bioenergy in electricity generation is expected to be 2% in 2050 (Syed, 2014).

Three geothermal demonstration generation projects were under development in 2014, expecting to add an estimated 662 MW of generation capacity between 2016 and 2018. It is expected that one of the projects will ultimately increase capacity by an additional 128 MW by 2020 (BREE, 2014). The purpose of the demonstration projects is to test geothermal electricity technology and explore potential reservoirs. Positive results from these projects could increase investor confidence and resource exploration. The government expects geothermal electricity generation to remain limited to 1% of electricity generation in 2050 as geothermal technology is not yet commercially viable in Australia (Syed, 2014). Similarly, two demonstration tidal energy projects totalling 484 MW are expected to become operational in 2016 (BREE, 2014). It is unlikely that tidal energy generation will increase in Australia unless it becomes commercially competitive.

Implications for Emission Levels

The Department of the Environment developed a business-as-usual scenario which forecasts Australia's emissions towards 2035. As Figure 13 shows, Australia's total GHG emissions (including LULUCF) are projected to reach 656 MtCO₂e in 2020, and 731 MtCO₂e in 2035 without the ERF or other policy measures to reduce emissions (Department of the Environment, 2015b). The electricity sector is projected to contribute the largest amount of GHG emissions, accounting for 31.8% in 2035. This is followed by emissions through direct combustion (17.5%) and transport (16%) (Department of the Environment, 2015b).

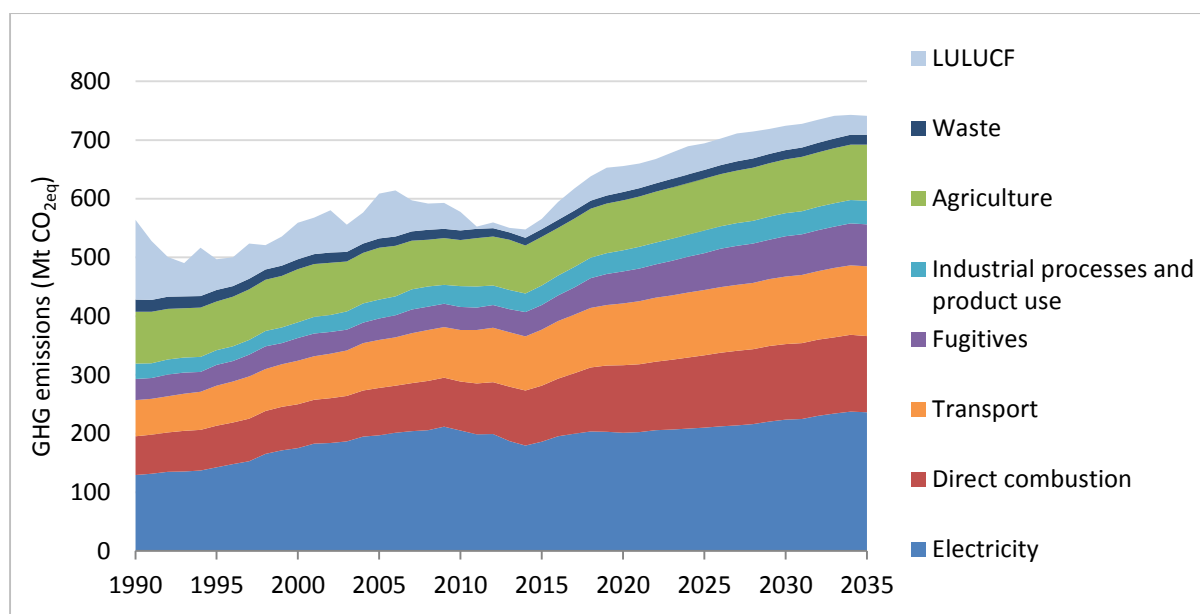


Figure 13: Australian Government projections of total greenhouse gas emissions, 1990-2035 (Department of the Environment, 2015b).

Figure 13 shows the drop in power sector emissions in 2013 and 2014 described in the previous section. This trend is likely to be reversed as the share of coal-fired generation without CCS increases towards 2050. Sectorial emissions are thus expected to increase. By 2020, GHG emission levels from the power sector are projected to rise 12% above 2014 levels and reach 201 MtCO_{2e}. They are expected to rise to 236 MtCO_{2e} by 2035, representing a 24% increase (Department of the Environment, 2015b). As the share of coal-fired generation in the electricity mix is expected to continue increasing beyond 2035, it is likely that power sector emissions from the power sector will continue rising towards 2050.

4.5.2 Asia Pacific Economic Cooperation Projections

The Asia Pacific Energy Research Centre (APERC) located in Tokyo, Japan, undertakes energy studies for the Asia Pacific Economic Cooperation (APEC) region. As members of APEC since 1989, Singapore and Malaysia are featured in the APEC Energy Demand and Supply Outlook (5th Edition) which forecasts future energy balances within each member country and the region as a whole. The APERC modelling provides detailed excel spreadsheets for each country containing projection data and was therefore chosen for inclusion in this report.

APERC has developed two main scenarios for the electricity generation mix of Australia towards 2035: a Business as Usual (BaU) scenario and a High Gas (HG) scenario. The BaU scenario is based on Federal Government policies. APERC's scenarios were developed before the Federal Government repealed the Clean Energy Package. Thus, its BaU scenario is based on estimations regarding the impact of a carbon tax, energy efficiency measures, and a future national carbon trading scheme (APERC, 2013a).

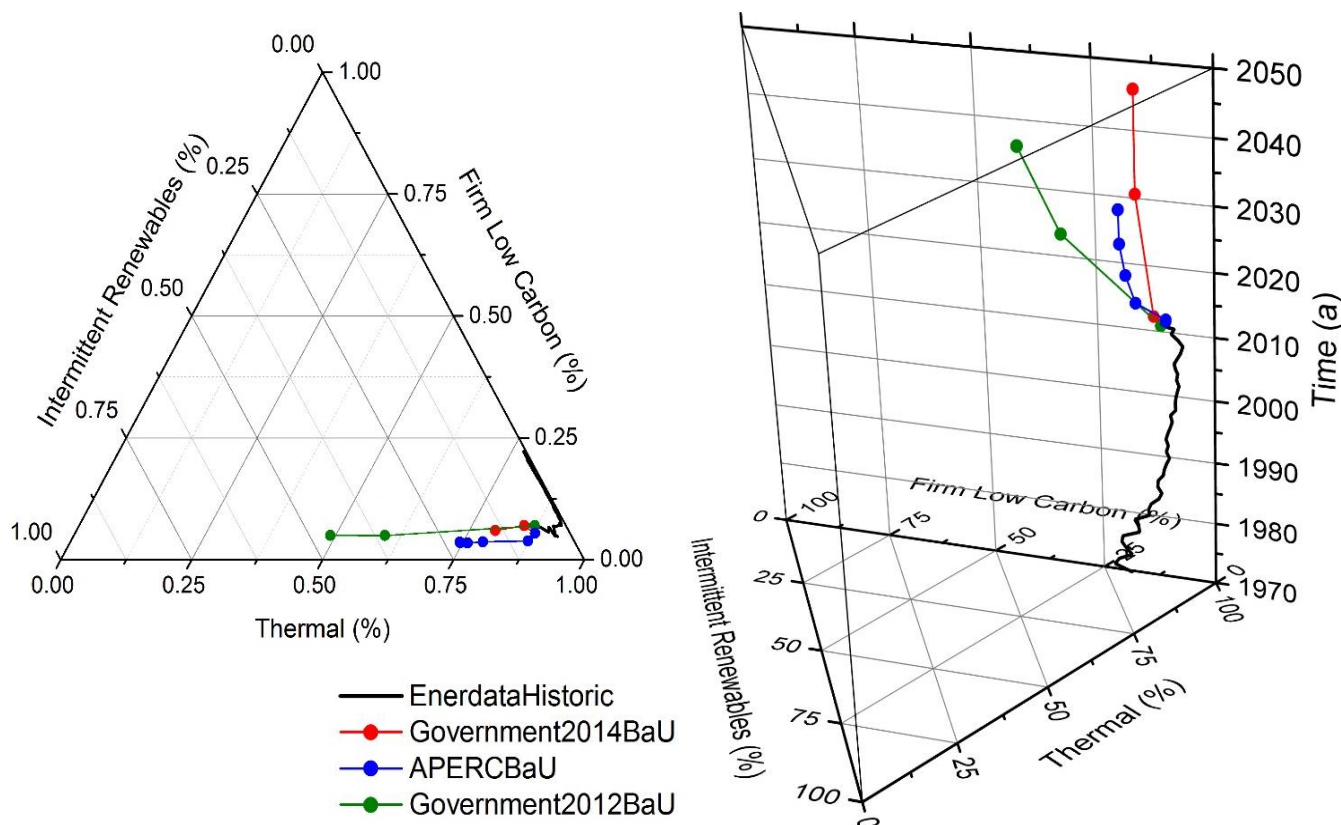


Figure 14: Australia's electricity generation according to scenarios, 1970-2050 (Syed, 2012; APERC, 2013b; Syed, 2014)

Figure 14 displays Australia's electricity generation according to the APERC scenarios and government projections. Thermal generation includes coal-, gas- and oil-fired generation and firm low carbon refers to nuclear and hydropower. Intermittent renewables include wind, solar, biomass, geothermal, wave and other renewable energy sources. As shown, the government's business as usual scenario from 2012 projected the largest decline in thermal energy sources, and increase in intermittent renewables. The government's updated 2014 BaU scenario which takes into account the removal of the carbon tax predicts a higher share of thermal generation. APERC scenarios project out towards 2035. Their BaU scenario is more optimistic regarding the share of intermittent renewables due to the assumption that the Federal Government's Clean Energy Package is still in place.

As shown in Figure 15, APERC predicts that coal-fired generation will decline from 199 TWh in 2015 to 132.7 TWh in 2035, as the installed capacity decreases from 37.8 GW to 30.8 GW (APERC, 2013b). Under both scenarios, gas-fired generation and renewable energy generation increases as the Australian government incentivises investment in low carbon generation through policy measures such as the RET and a carbon price mechanism (APERC, 2013a). Due to the repeal of the carbon tax, and Australia's domestic gas prices, it is unlikely that this high degree of substitution between coal- and gas-fired generation will occur. This scenario is more in line with the government projections from 2012.

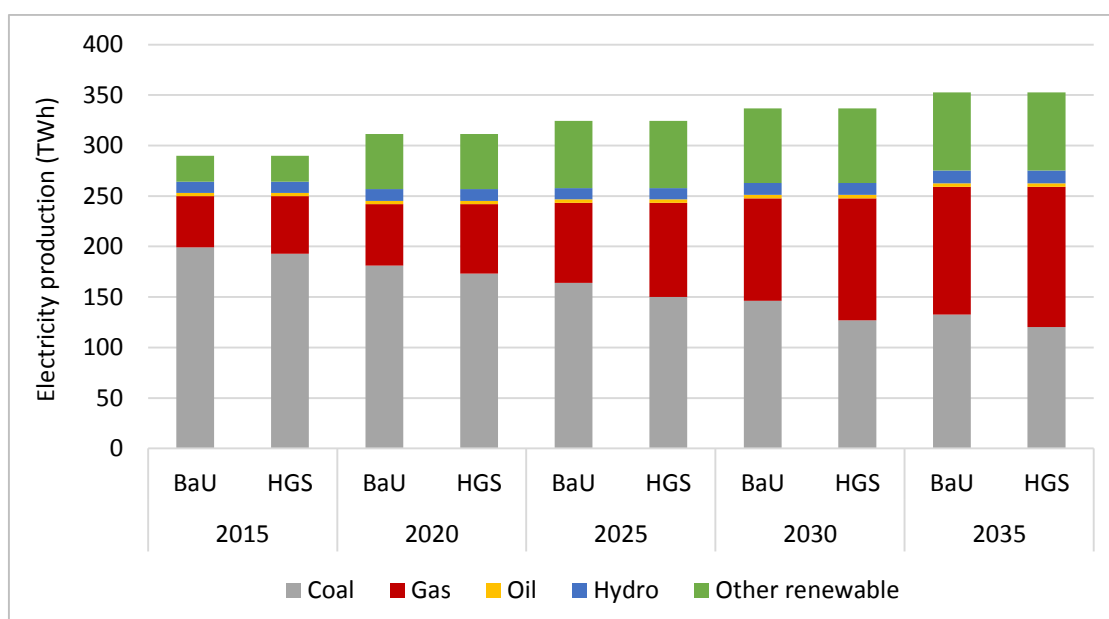


Figure 15: APERC Scenario comparison of electricity generation, 2010-2035 (APERC, 2013b).

The HG scenario considers the impact of increasing gas production and trade at prices similar to BaU or lower (APERC, 2015a). It forecasts that Australia's domestic production increases 3% by 2035, due to development of its conventional and unconventional gas reserves (APERC, 2015a). As the majority of this gas is expected to be exported, this increased production is only expected to increase the share of gas-fired generation by 3%, causing a 4% decline in coal-fired generation compared by 2035 compared to the BaU Scenario (APERC, 2013b).

Both scenarios predict that hydropower generation remains stable. Similarly, both scenarios expect oil-fired generation to remain limited. These conclusions are consistent with government projections. The HG scenario does not predict a higher share of renewable energy sources in the electricity mix than the BaU scenario. As both scenarios assume a carbon tax is in place, they predict renewable energy sources to account for 22% of the generation mix in 2035. Government projections before the repeal of the carbon tax predicted a larger share of 35% (Syed, 2012). APERC expects gas-fired capacity to play a larger role than renewable energy sources. It is possible that this difference is due to different assumptions regarding the future cost of gas and the learning curves of renewable energy technology. Figure 16 depicts Australia's CO₂ emissions by sector towards 2035 in APERC's BaU and HG scenarios. As the share of gas-fired generation is slightly higher in the HG scenario than in the BaU scenario, emission reductions are higher in the HG scenario. The HG scenario foresees a reduction of 5% in power sector emissions by 2035 (APERC, 2013a). These reductions in emissions from the power sector are driven by the expectation that the share of coal-fired generation decreases towards 2035. As outlined, this is unlikely to happen. Under current policy

scenarios, it is more likely that emissions in the power sector continue increasing, as projected in recent government scenarios.

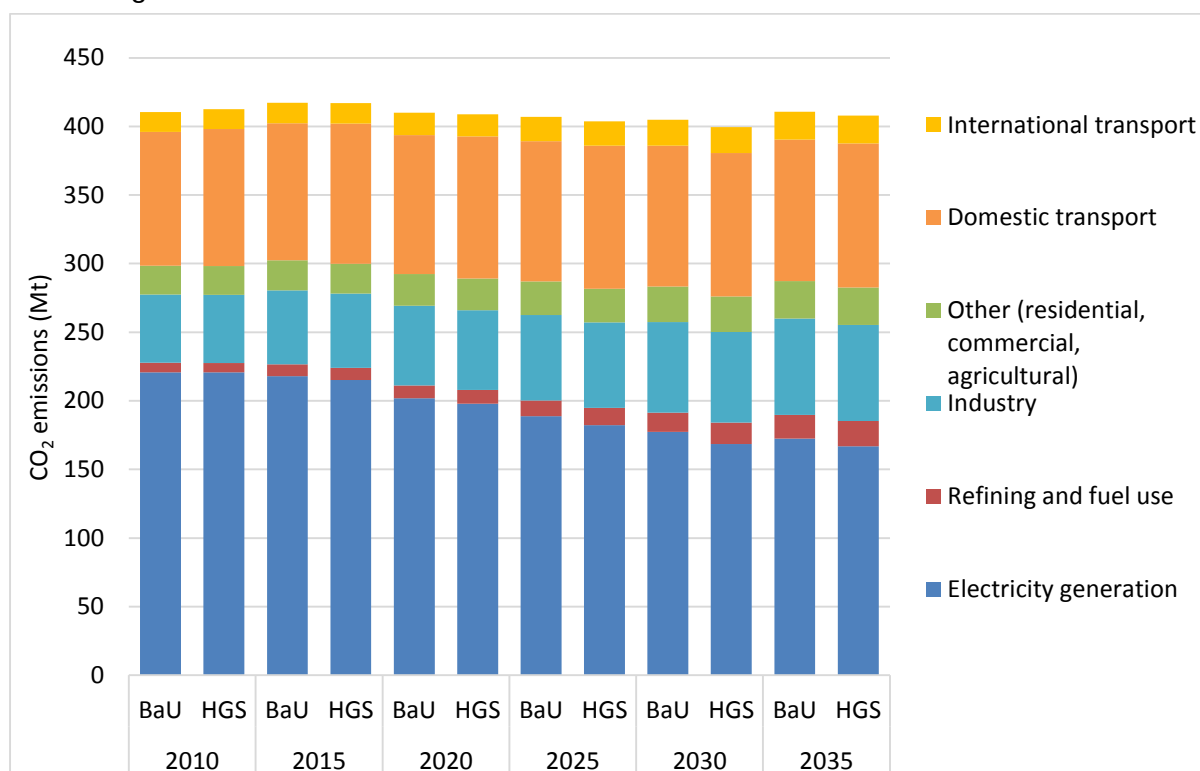


Figure 16: APERC Scenario comparison of sectorial emissions, 2010-2035 (APERC, 2013a).

APERC's BaU scenario predicts that the carbon intensity of GDP will decrease by 0.5% between 2010 and 2035, in part due to fuel switching in the electricity sector (APERC, 2013a). The energy intensity of GDP is also expected to decline by 2.2% over this time period. Although it is possible that the Australian carbon intensity of GDP and energy intensity of GDP decline towards 2035, this is unlikely to be caused by a reduction in the carbon intensity of the power sector. Intensity reductions would have to be driven by other sectors of the economy for APERC's projections to remain valid.

4.6 Summary

Ensuring Australia's competitiveness on the international energy market and reducing domestic energy costs to businesses and households are the key drivers shaping Australia's energy policy. These objectives have led the government to repeal its Clean Energy Package. Although the Direct Action Plan is intended to cause emission reductions, it is unclear what the effects of the plan on the power sector will be. While a safeguard mechanism is intended to ensure that Australia's largest emitters remain within quantified baseline emission levels, these baseline levels are determined according to the highest point of emissions in the sector over the past five years. This makes it likely that the baseline will be relatively high and not result in any additional emissions abatement.

The removal of the carbon tax seems to have had large implications for the power sector. While government projections and APERC scenarios previously predicted that gas would displace coal as the main source of fuel for generation towards 2035, this is unlikely to occur under the current policy climate. The increase in gas prices seems to exacerbate the trend away from the installation of gas-fired generation. Although Australia's natural gas production is set to increase, a significant portion of production is expected to be exported through its LNG export facilities. This is reflected in APERC's HG scenario, which forecasts that increased domestic natural gas production would only lead to a 3% increase in gas-fired generation relative to the BaU scenario. It is likely that the share of gas-fired generation will remain stable and decrease slightly towards 2035 and 2050 as it is less cost-competitive than coal-fired generation.

Furthermore, energy policy reform has created uncertainty in the renewable energy market and caused a marked decrease in investment in the sector. While the Renewable Energy Target is likely to be achieved by 2020, it is unlikely to be extended. Although wind projects represented 47% of new capacity in 2014, it is likely that the trend towards renewable energy generation reverses once construction of this capacity has been completed. Despite Australia's large renewable energy potential, AEMO expects that no new renewable energy capacity will be constructed after 2020 due to lack of incentives. Thus, it is likely that the share of renewable energy generation will decline towards 2050.

Due to the country's large and easily accessible coal reserves, coal-fired generation is relatively cheap. The share of coal-fired generation is expected to increase towards 2050. Although the carbon intensity of generation has declined since 2009, it is likely to increase as the share of lower carbon sources declines and coal-fired generation increases. Furthermore, unless the cost of CCS reduces, it is unlikely that it will be installed.

These factors make it likely that emissions from the power sector will keep increasing towards 2035 and beyond to 2050. This contrasts to the stabilisation of sectorial emissions envisaged by APERC's scenarios under previous policy conditions. This has wider implications to Australia's emission levels. Due to the large share of electricity generation in the country's GHG emission levels, it is unlikely that Australia's carbon intensity of generation and its energy-related emission levels will decline unless reductions come from other sectors.

5 CHINA

Highlights

- China is the world's largest CO₂ emitter, accounting for 27% of global emissions. According to the PBL Netherlands Environmental Assessment Agency, its relative contribution to global CO₂ emissions from 1850 to 2010 is 11.6%.
- China pledged to peak emissions by 2030, but did not set an emissions level. It aims to lower CO₂ emissions per unit of GDP 40-45% by 2020, and 60-65% by 2030 below 2005 levels. These targets are primarily expected to be achieved through energy efficiency measures.
- China is restructuring its economy to achieve growth that is more environmentally, social and economically sustainable. This new development model is characterised by a shift away from government-led investment towards greater domestic consumption, the growth of the service sector, environmental protection and reductions in environmental damage, and greater efficiency.
- China is the world's largest investor in renewable energy. It has the world's highest installation rates for wind power. Generation from renewable energy sources is constrained by transmission bottlenecks. In 2013, 16% of installed wind capacity was not connected to the grid.

5.1 Background

China is the most populous country in the world. With a population of 1.36 billion people in 2013 it accounts for 19% of global population (IMF, 2015; WB, 2015a). It had an annual average GDP growth rate of 10% between 2000 and 2012, and grew to represent 15% of the global economy in 2014, accounting for the third largest share behind the European Union (17%) and the United States (16%) (Janssens-Maenhout et al., 2014). The Chinese growth rate is a significant driver for global economic growth, accounting for 31% of global economic growth since 2002 (Janssens-Maenhout et al., 2014). Although still classified as a developing country by the World Bank, China's income level is considered 'upper middle income', with a GDP per capita of US\$ 6,807 in 2013 (IMF, 2015; WB, 2015a).

Historically, China's economic growth has relied on the manufacturing and industry sector of the economy. In 2012, however, the service sector of the economy contributed 44.6% of GDP, overtaking the industry and construction sector for the first time. In 2013, it was the fastest growing sector of the economy. While the agriculture, mining, and fishery industries were considered a cornerstone to Chinese development in the 1970s, this sector of the economy decreased to contribute 10% to GDP in 2013 (NBS, 2014). This reflects a restructuring of the Chinese economy away from heavy-industry growth towards higher value-added growth (APEREC, 2013a).

Rising urbanisation levels have accompanied this economic growth, increasing from 26.4% in 1990 to 53% in 2013 (IDDRI & SDSN, 2014). The Chinese government is actively promoting urbanisation, with plans to reach an urbanisation level of 70% by 2025 (Johnson, 2013). The government has begun restructuring the economy towards a more consumer-led growth model, and so creating a larger base of urban consumers has become a key pillar for

development (Johnson, 2013). Between 200 and 250 million people are estimated to move to cities in the next decade (Johnson, 2013; Li & Wang, 2012). This is expected to lead to a rise in the demand for energy, water, and other resources (Barr & Zhang, 2013).

China's primary energy consumption increased by 8.1% annually on average between 2000 and 2011 (Enerdata, 2015b). The energy demand growth rate has slowed since 2011, growing 4.7% in 2013 (Enerdata, 2015b). Industry is the largest consumer of energy (52%), followed by the residential and service sector (28%) and the transport sector (13%). The share of the service sector in energy consumption is expected to increase as China shifts away from heavy-industry growth (APEREC, 2013a). Energy consumption in the transport sector is also expected to increase as the road transport system develops (Enerdata, 2015b).

5.1.1 Emissions

Whereas Australia publishes a quarterly update of its National Greenhouse Gas Inventory, China's latest Inventory was published in 2005 for the Second National Communication on Climate Change of China (UNFCCC, 2012). In 2005, China's GHG emissions (excluding LULUCF) were 7.05 GtCO₂e. Energy-related industries accounted for approximately 77% of total Chinese GHG emissions in 2005 (IDDRI & SDSN, 2014). Emissions from the agricultural sector accounted for 11%, while industrial processes and fugitive emissions accounted for 10.26% (UNFCCC, 2012).

China's high emission levels are a result of its economic growth model. China's economic development since the 1980s has been characterised by double-digit growth rates, driven by high levels of government-led investment, infrastructure development of energy-intensive industrial sectors (such as steel, iron and cement) (Green & Stern, 2015). Until 2010, emissions grew faster than GDP, as depicted in Figure 17 (IDDRI & SDSN, 2014). China's government has targets to reduce the energy-intensity and emissions-intensity of the economy, as outlined in the following section.

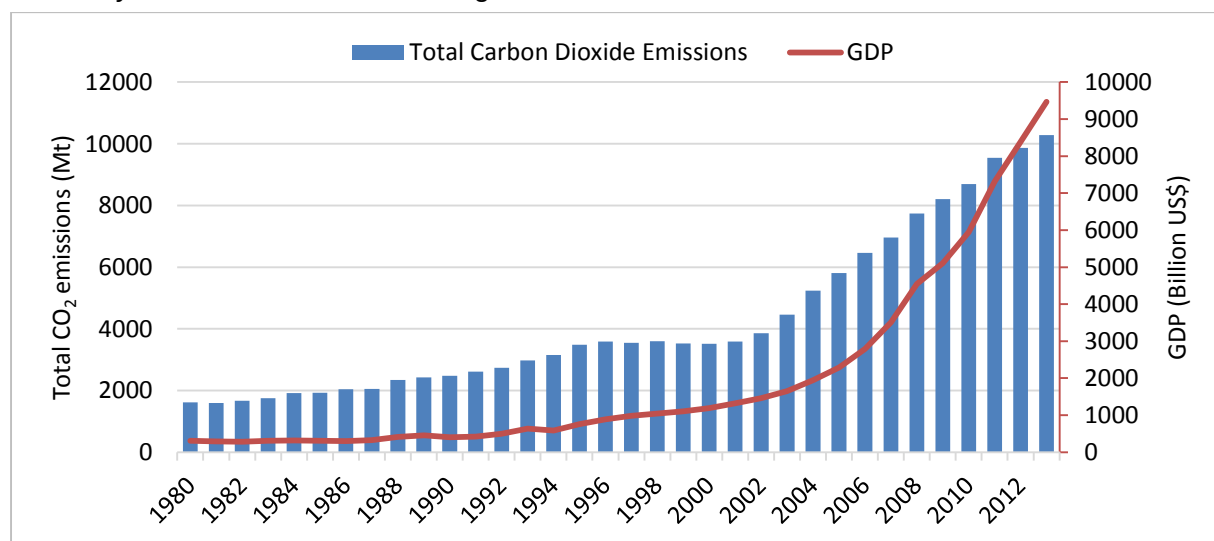


Figure 17: China's GDP (World Bank, 2015) and CO₂ emissions (EDGAR, 2015), 1980-2013.

As Figure 18 depicts, manufacturing and construction accounted for the largest share of CO₂ emissions until 2010, when the power sector became the largest emitter. This is due to the power sector's reliance on fossil fuel. China's energy-related CO₂ emissions from the electricity sector has risen from 1,234 MtCO₂ in 2000 to 4,004 MtCO₂ in 2014 (Enerdata, 2014a). In 2014, the power sector accounted for 46% of CO₂ emissions from China's energy-related activities (Enerdata, 2014a). Industry is the largest consumer of electricity, consuming 64% of electricity generation in 2013 (Enerdata, 2014a).

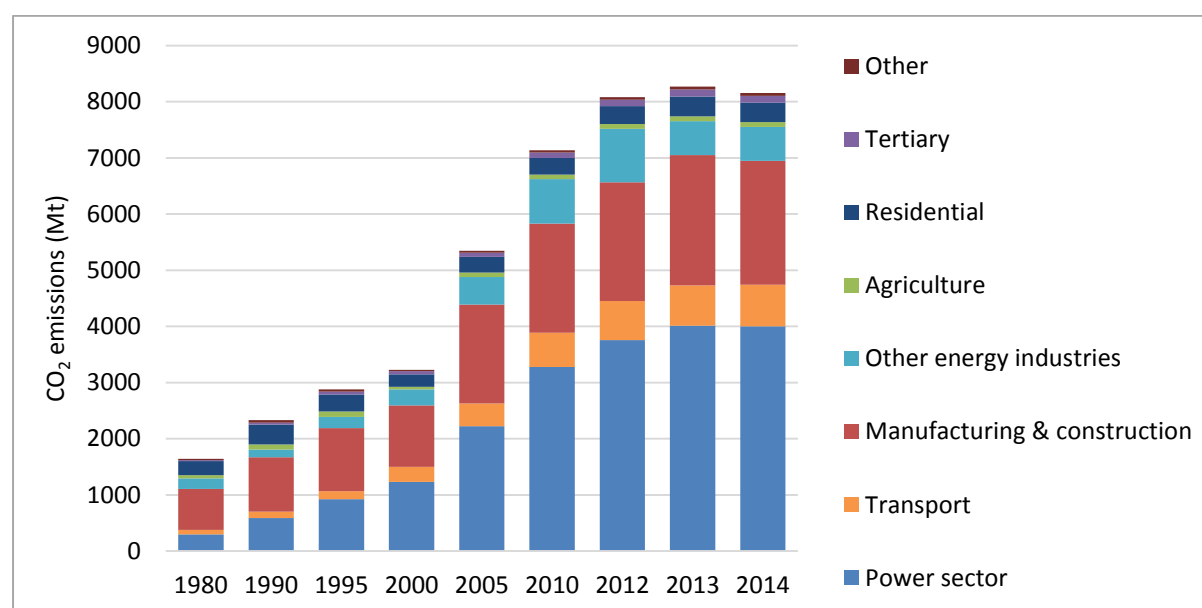


Figure 18: China's energy-related CO₂ emissions by sector, 1980-2014 (Enerdata, 2015e).

5.1.2 Climate Change Targets

Classified as a non-Annex 1 party to the Convention on Climate Change, China is not legally bound to meet quantified targets regarding the reduction of greenhouse gas emissions under the Kyoto Protocol. China's commitments are therefore voluntary and non-binding. China's Copenhagen Accord pledge is to reduce CO₂ emissions per unit of GDP 40-45% by 2020 relative to 2005 (Climate Action Tracker, 2015a). China submitted its INDC to the UNFCCC in June 2015, outlining the aim to lower carbon intensity of GDP by 60 to 65% by 2030 below 2005 levels (Climate Action Tracker, 2015a). As the targets are intensity targets, emission levels will vary relative to the level of GDP.

In November 2014, the US and China released a bilateral announcement on climate change. According to the agreement, China aims to increase the share of non-fossil fuels in the primary energy mix to 20% by 2030. Furthermore, China intends to peak its CO₂ emissions around 2030, with the aim of peaking earlier (The White House, 2014). China has not stated an absolute emission value at which emissions will peak. Table 6 provides an overview of China's climate change targets.

Table 6: China's Key Energy Policy Targets

	2015	2020	2030
Total CO₂ Emissions			Peak emissions (earlier if possible)
Non-fossil share in primary energy consumption	11.4%	15%	20%
Carbon intensity (CO₂ emissions per unit of GDP)	Reduce 17% below 2010	Reduce by 40-45% below 2005	Reduce by 60-65% below 2005
Energy intensity (energy use per unit of GDP)	16% reduction of energy use per unit of GDP relative to 2010		

5.2 China's Electricity System

5.2.1 Electricity Market

In 2013 the National Energy Administration (NEA) was created to regulate the electricity sector. The NEA is a department of the National Development and Reform Commission (NDRC), which is responsible for formulating and coordinating economic and social development (NDRC, 2015). The NEA is supervised by the National Energy Commission, which was created in 2010 to centrally determine the national energy development strategy (Enerdata, 2015b).

There are five main power generating companies in China: China Huaneng, China Guodian, China Datang, China Huadian, and China Power Investment. Together, these account for more than 45% of national electricity generation (Enerdata, 2015b). These generating companies are all State-Owned Enterprises (SOEs). Local-owned businesses and independent power producers (IPPs) generate the remaining electricity supply, often in partnership with provincial and local governments (EIA, 2015a). In 2010, local governments operated approximately 30% of generation (Bergsager & Korppoo, 2013).

There is no single national electricity grid, and so electricity is currently transmitted through six networks. These six networks are NorthEast China Power Network, North China Power Network, East China Power Network, Central China Power Network, North West China Power Network, and China Southern Power Grid (Enerdata, 2015b). China Southern Power Grid Ltd. owns the China Southern Power Grid, which supplies electricity to the southern provinces of Guangdong, Guangxi, Yunnan, Guizhou and Hainan. The remaining five networks are owned by the State Grid Corporation of China (Enerdata, 2015b).

China became the world's largest electricity generator in 2011. Economic and industrial demand caused electricity consumption to increase 11% per year on average between 2000

and 2013 (Enerdata, 2015b). The industrial sector is the largest consumer, accounting for three-fourths of electricity demand in (EIA, 2015). The NEA expects electricity consumption to be 5700 TWh by the end of 2015 (Enerdata, 2015c).

5.2.2 Energy Resources and Trade

Fossil Fuel Resources

As shown in Table 7, China houses 12.8% of global proved reserves of coal, third globally behind the US and Russia (BP, 2015). Anthracite and bituminous coal take up the largest share of China's total proved reserves, with 62,200 Mt at the end of 2014 (BP, 2015). Bituminous coal remains the most widely produced, accounting for 77% of total coal production (Fridley, 2014). The largest coal producing provinces are the northern provinces of Inner Mongolia, Shanxi and Henan, together accounting for 61% of national coal production (Fridley, 2014). By contrast, the largest coal consuming provinces are located in eastern China (EIA, 2015a).

Table 7: China's Fossil Fuel Resources (BP, 2015)

Fossil fuel	Reserves	2014 share of world total	R/P (years)
Oil			
Total proved reserves	2.5 thousand Mt	1.1%	11.9
Production	211.4	5%	-
Consumption	520.3	12.4%	-
Natural gas			
Total proved reserves	3.5 trillion m ³	1.8%	25.7
Production	134.5 billion m ³	3.9%	-
Consumption	185.5 billion m ³	5.4%	-
Coal			
Total proved reserves	114500 Mt	12.8%	30
Production	1844.6 Mtoe	46.9%	-
Consumption	1962.4 Mtoe	50.6%	-

China is the world's largest coal consumer, accounting for 50.6% of global coal consumption (EIA, 2015a). China became a net importer in 2009, despite the nation's large coal reserves. This is in part due to the geographical mismatch between reserves and demand, and the high cost associated with transporting coal domestically. The government is investing in railway infrastructure to overcome coal transportation bottlenecks and reduce costs (EIA, 2015a). Furthermore, the government is promoting investment in ultra-high voltage transmission lines so that coal-fired power stations can be constructed closer to coal supply centres, and electricity transported over long distances (Yang, 2015). This is also intended to reduce air pollution in cities. Approximately 65% of coal imports are supplied by Indonesia and Australia (EIA, 2015a).

In 2014, growth in Chinese coal consumption slowed due to a decline in Chinese energy demand (Dale, 2015). This is in part due to a shift away from heavy industry as part of a

restructuring of the Chinese economy. This slowdown in Chinese demand affected the global coal trade, as global coal consumption grew by its slowest rate since 1998 (Dale, 2014). This highlights the importance of China in the global energy trade. The power sector consumes approximately half of Chinese coal. The industrial sector is the second largest consumer of coal, accounting for 41% of Chinese coal consumption in 2012 (EIA, 2015a).

China's natural gas reserves are estimated at 3.5 trillion m³, with an R/P ratio of 25.7 years (BP, 2015). Natural gas was China's largest growing fossil fuel source from 2013 to 2014 (BP, 2015). The industrial and residential sectors of the economy have traditionally been the largest consumers of gas. Since 2004, however, gas consumption has been steadily increasing in the power and transportation sectors. (EIA, 2015a).

China became a net importer of gas in 2007, with imports accounting for 32% of natural gas demand in 2013 (EIA, 2015a). The majority of Chinese natural gas is imported from Central Asia via pipelines. China is the third-largest LNG importer globally, with Australia supplying the majority of LNG imports in 2010 (Fridley, 2014). China also has the world's largest potential shale gas resources at 25-32 tcm (Enerdata, 2015b). Chinese shale gas exploration is in the early stages of development. Several SOEs are partnering with international oil companies to secure technological knowledge and investment. In 2012, for example, the China National Petroleum Corporation partnered with Shell to explore the shale gas potential of the Sichuan basin (EIA, 2015a). Chinese SOEs are also investing in shale gas projects overseas to gain technical expertise (EIA, 2015a).

Oil reserves are estimated at 2.5 thousand Mt, with an R/P ratio of 11.9 years (BP, 2015). China is the fourth-largest producer of oil products, producing primarily crude oil (92% of production in 2014) (EIA, 2015b). In 2014, China replaced the United States as the world's largest net oil importer (Dale, 2015). Approximately 43% of global growth in oil consumption in 2014 was due to the growth in Chinese oil consumption, highlighting the significant influence China's energy consumption has on global consumption patterns (EIA, 2015b).

Renewable Energy Sources and Hydropower

As displayed in Table 8, China has large renewable energy potential. According to the NEA, China's solar power capacity is 2200 GW. This calculation assumes 20% of rooftops and 2% of the Gobi Desert and other remote locations in China are covered with solar panels (NEA, 2011). China has already started construction on solar panels in the Gobi Desert, increasing installed capacity threefold from 2012 to 2015 (Koch, 2015). The south-western regions in China receive the highest solar radiation per square metre nationally (Liu et al., 2009). As these are removed from the main electricity demand centres in the east, transmission grid infrastructure is necessary to exploit this potential.

Table 8: China's Renewable Energy Resource Potential (Adapted from NEA, 2011)

Resource	Unit	Economic Exploitable Capacity	Technical Exploitable Capacity	Theoretical Capacity
Hydropower				
Installed capacity	GW	402	542	694
Annual electricity generation	TWh	1753	2474	6083
Biomass	Mtce	280	-	-
Solar Power	GW	-	-	2200
Wind	GW	-	-	2750
On-shore	GW	-	-	2560
Off-shore	GW	-	-	190
Ocean power	GW		-	1495
Tidal	GW	-	-	22
Wave	GW	-	-	13
Current	GW	-	-	14
Salinity	GW	-	-	125
Temperature Difference	GW	-	-	1321

The government estimates that wind power potential totals 2750 GW, with 2560 GW from onshore installations and 190 GW off-shore (NEA, 2011). The country's wind potential is the greatest in the northern regions of Inner Mongolia, Heilongjiang, Jiling and Liaoning, as well as in the western regions of Tibet, Xinjiang, Qinghai and Gansu (McElroy et al., 2009). As with solar power, investment in the transmission grid is key to exploiting this potential.

With 3886 rivers with a hydropower potential of more than 10 MW each, China has a large theoretical hydropower potential (Chen & Wang, 2010). Southwest China has the largest hydropower potential, followed by the southern regions. There are barriers to exploiting this potential, as the ecological system is fragile in these regions (Hu et al., 2014). Furthermore, there is social opposition due to the government's resettlement of populations in surrounding areas (EIA, 2015a).

5.3 Energy Policy and Drivers

China's rapid economic growth has enabled the nation to lift 500 million people out of poverty over the last three decades and established China as the third largest economy in the world (World Bank, 2015). The nation's development model, however, relied on resource- and energy-intensive heavy industry (Stern and Green, 2015). This led to widespread environmental degradation. According to a study published by the Chinese Academy of Environmental Planning, the cost of environmental degradation in China was estimated to be 3.5% of GDP in 2010 (Wong, 2013).

There is a growing concern amongst Chinese citizens regarding the effects of climate change and pollution on public health and standards of living. Social dissatisfaction is increasingly

being expressed in the public sphere. In 2005, there were an estimated 51,000 pollution-related protests across the country (Economy, 2007). There is thus an increasing pressure on the government to implement policies to mitigate and adapt to a changing climate.

Furthermore, the continued growth of China's demand for fossil fuels is making the nation increasingly reliant on foreign imports to sustain industry and encourage economic growth. As outlined, China is already a net importer of coal, natural gas, and oil. China is facing a geographical mismatch of where its unexploited reserves are located, and its major energy demand centres. By 2015, the International Energy Agency (IEA) predicts that foreign energy will supply 60-70% of total Chinese energy consumption (Zhang, 2011). A major challenge facing China is how to ensure energy security whilst facing geopolitical uncertainties and global energy fluctuations (EIA, 2015a).

In 2013, President Xi announced that China's current economic growth strategy is 'unbalanced, uncoordinated, and unsustainable' (quoted in Green & Stern, 2015). Future economic growth is hindered by China's dependence on energy imports, local resource constraints, and the cost of environmental degradation (Green & Stern, 2015). Furthermore, although government-led investment has stimulated economic growth, it has also led to overcapacity in China's energy-intensive industrial sector (Green & Stern, 2015). Due to these considerations, the government is moving away from its traditional growth strategy. It is restructuring its economy to achieve growth that is more environmentally, socially and economically sustainable (Amal-Lee, Holmes, & Ng, 2014). This new development model is characterised by a shift away from government-led investment towards greater domestic consumption, the growth of the service sector, environmental protection and reductions in environmental damage, and greater efficiency (Green & Stern, 2015).

This restructuring has changed the focus of China's energy policy, as outlined in the nation's Five-Year Plans (FYP). FYPs serve as the foundation for China's near-term social economic policies, prescribing targets and guidelines across a range of economic, social and environmental issues for five year periods. While energy has always featured prominently in the FYPs the 11th (2006-2010) and 12th (2010-2015) FYPs embody a shift in the government's stance towards energy. While previous Plans only outlined total energy production and fuel targets to further economic growth, the latest two Plans included measures to further environmental protection and promote efficient resource exploitation (Yuan & Zuo, 2011; Fridley et al., 2013). These Plans were the first to introduce energy efficiency standards and a commitment to reducing specific pollutants (Fridley et al., 2013).

China's 12th FYP has four key energy policy targets that are to be achieved between 2011 and 2015:

1. Reduce energy intensity of GDP 16% relative to 2010 levels;
2. Reduce emissions intensity of GDP 17% relative to 2010 levels;

3. Increase the non-fossil fuel share of total energy use to 11.4% by 2015. This has since been expanded to include a 2020 target (15% non-fossil fuel share) and 2030 target (20% non-fossil fuel share);
4. Promote seven priority industries to increase their contribution to GDP. Three of these are directly correlated to the energy sector. These are the promotion of new energy (such as nuclear, wind and solar power), the environmental protection and energy conservation, and the development of clean energy vehicles (Enerdata, 2015b; LSE, 2015).

An initial draft of the 13th FYP is due to be released in October 2015 and approved by the National People's Congress in March 2016 (Lan, 2015a). The NDRC, in charge of developing the FYPs, has stated that the 13th FYP will continue to promote energy efficiency and increase environmental protection (Lan, 2015a). The 13th FYP will also likely outline efforts to establish a nation-wide emission trading system (Bergsager, Korppoo, 2013).

Table 9 provides an overview of China's key energy policies. The following sections outline how the government aims to achieve these targets through energy efficiency measures, reducing emissions, and promoting low-carbon energy sources.

Table 9: China's Key Energy Policies

Date	Policy	Details
2009	Renewable Energy Law	Outlines purchasing obligations of renewable energy generation for grid companies FiT for renewable energy generation
2011-2015	12 th Five-Year Plan	Target to reduce energy intensity of the economy by 16% compared to 2010 Target to reduce carbon intensity by 17% compare to 2010 Increase non-fossil fuel share to 11.4% of primary energy consumption by 2015
2014-2020	National Plan for Tackling Climate Change	Cut carbon intensity of the economy by 40-45% by 2020 from 2005 levels Increase non-fossil fuel share to 15% of primary energy consumption by 2020
2014-2020	Energy Development Strategy Action Plan	Caps annual coal consumption at 4.2bn tonnes until 2020 Limits share of coal in primary energy consumption to 62% by 2020 Target to reach 85% energy self-sufficiency Increase natural gas share to 10% of primary energy consumption

Promote Energy Efficiency

Energy efficiency and conservation are seen as 'low hanging fruit', and are thus the top priority in China's energy strategy (Campbell, 2014). It is expected that China's energy intensity and CO₂ intensity reduction targets are mainly going to be achieved through energy efficiency

measures, with an additional role for the replacement of thermal capacity with low-carbon capacity (Li & Wang, 2012).

The 12th FYP plan includes a target of reducing the energy intensity of coal-fired power plants by 8% (Enerdata, 2015b). This has led to the shutting down of small and inefficient mines and power plants across the country. According to government statements, approximately 94.8 GW of ageing and inefficient thermal capacity was taken offline between 2006 and 2013 (Gaoli, 2014). Another 60 GW is expected to come offline between 2016 and 2020 (Bloomberg Business, 2015). Since 2008, government regulation requires all new coal-fired power plants to be supercritical or ultra-supercritical power plants. In 2014, 13% of installed coal-fired power plants used supercritical or ultra-supercritical technology (Enerdata, 2014a).

The 12th FYP outlined the investment of RMB 2.55 trillion (approximately US\$ 401 billion) in power grid construction (KPMG, 2011). The electricity network construction and transformation of action plan 2015-2020 states that RMB 2 trillion (US\$315 billion) will be invested in the network over the five years (NEA, 2015). This is to increase efficiency, as well as overcome grid constraints that prevent renewable energy sources of generation from being connected to the grid. China's State Grid and the Southern Grid are in the process of developing smart grids with the intention of building a smart-grid system by 2020 to increase efficiency and increase the integration of renewable sources into the grid (KPMG, 2011). Smart grid investments totalled US\$ 4.3 billion in 2013 (Enerdata, 2015b). Furthermore, the government intends to improve connectivity across the country. In February 2015, the NEA outlined its commitment to construct ultra-high voltage transmission lines to connect China's resource-rich but sparsely populated western regions, to the eastern regions where electricity demand is higher (Yang, 2015). Through 2020, China's State Grid Corporation has committed to investing US\$ 88 billion to build ultra-high voltage transmission lines (Campbell, 2014).

Reduce Emissions and Air Pollution

China has been attempting to curb the importance of coal in its economy in order to reduce air pollution. China's Energy Development Strategy Action Plan (2014-2020) caps annual coal consumption at 4.2 billion tonnes until 2020. It also limits the share of coal in primary energy consumption to 62% by 2020, compared to 66% in 2014 (LSE, 2015; BP, 2015). As coal combustion in the power sector is one of the main sources of China's CO₂ emissions, these targets have large implications in the power sector. The government has announced that no new coal-fired power plants will be constructed after 2030 (China Electricity Council, 2015). Furthermore, the Energy Development Strategy Action Plan imposed a coal-burning ban in the three biggest city clusters of Beijing, the Yangtze River Delta and the Pearl River Delta by 2020 in order to reduce air pollution in these areas (LSE, 2015). Beijing has already started shutting down coal-fired power plants around the city, and is constructing gas-fired plants to provide electricity to the capital (Bloomberg Business, 2015).

Seven areas in China have implemented pilot emission trading schemes. This includes the cities of Shenzhen, Beijing, Shanghai, Chongqing, Tianjin, as well as the provinces Hubei and Guangdong. Each scheme has different objectives and measures in place. The government aims to launch a national ETS by 2017 (Enerdata, 2015b). As the regional pilot schemes differ in their approach, a key obstacle to implementing a national scheme is to overcome these differences. This requires national guidelines and rules that can be applied locally to remain in line with operating under a national emissions cap (Enerdata, 2015b).

Increase the Share of Non-Fossil Fuels

China's primary energy consumption targets (as summarised in Table 6) have translated into capacity targets for the power sector, as summarised in Table 10. The FYP outlined targets towards 2015, while the Medium and Long Term Development Plan for Renewable Energy outlines targets and policies for renewable energy development towards 2020 (NDRC, 2007). These targets are regularly updated in interim reports to reflect developments in the industry.

Table 10: China's Installed Electricity Capacity Targets (den Elzen et al., 2015; Moch, 2014)

	Status		Targets			Exploitable Capacity	
	2014 GW	%	2015 GW	%	2020 GW	Technical GW	Economic GW
Fossil Fuels							
Oil	15	1.1	15	1.0	-	-	-
Gas	41	2.9	56	3.8	-	-	-
Coal	895.2	63.7	960	64.4	-	-	-
Total thermal capacity	951.2	67.7	1031	69.2	-	-	-
Nuclear	19.9	1.4	40	2.7	58	-	-
Hydroelectricity	301.8	21.5	290	19.5	420	542	402
Renewables							
Biomass and Waste	8.5	0.6	13	0.9	30	-	280
Wind	96.4	6.9	100	6.7	200	2750	-
Solar	28.1	2.0	35	2.3	100	2200	-
Tidal					0.1	22	-
Total renewable capacity	133	9.5		9.9		-	-
Installed capacity	1406	100	1490	100	-	-	-

The government's initial aim was to install 60-70 GW of nuclear capacity by 2020. This was adjusted downwards to 58 GW after the Fukushima accident in 2011 (EIA, 2015a). By 2020, the government aims to have an additional 30 GW under construction (EIA, 2015a). As shown in Table 10, reaching the government's low-carbon energy targets increases the share of nuclear power to 2.7% of total installed capacity, hydropower to 19.5% of installed capacity, and renewable energy capacity to 9.9%. In August 2015, China's official targets were to install

30 GW of biomass, 200 GW of wind, and 50 GW of solar by 2020 (den Elzen et al., 2015). By 2020, the government intends to increase installed hydro capacity to 420 GW (Moch, 2015). In total, the government aims to install 700 GW of renewable energy capacity (including hydropower) by 2020.

To encourage renewable energy investment by local governments, the national government is expected to implement a renewable energy quota system, under which provincial governments will be allocated individual renewable energy (excluding hydropower) installation targets. The majority of wind and solar installed capacity is currently in the northern and western parts of China. This system is expected to increase renewable energy capacity in eastern provinces, where electricity demand is the highest (The Climate Group, 2015).

As outlined, state-owned enterprises and local governments control the majority of China's generation capacity. These generators are encouraged to meet targets outlined in the FYPs and other policies. As China shifts away from a government-led investment model, it is likely that the share of private sector investment will increase in the power sector. In March 2015, the State Council released a reform plan entitled 'Opinions Regarding the Deepening of the Power Sector's Reform' (Lan, 2015b). The plan envisages a greater role for private sector investment and outlined the need to restructure SOEs to make them more efficient. The plan also indicates that electricity prices will gradually be opened to market influences instead of being set at the government level. Furthermore, the reform package envisages greater competition in electricity generation and distribution (Lan, 2015b). Several market measures are in place to encourage investment in renewable energy sources. The Renewable Energy Law introduced FiTs for wind and biomass, which were revised in 2009. In 2011, FiTs for solar were introduced. The central government sets state level subsidies to PV rooftop projects and provides a FiT to project owners that generate a surplus of power (The Climate Group, 2015). Additional FiTs are set at provincial level, and funded through a surcharge paid by electricity users (Enerdata, 2015b).

5.4 Current Generation Capacity

Total installed capacity was 1405.8 GW at the end of 2014 (Enerdata, 2014a). As Figure 19 shows, coal-fired generation has dominated the power sector since the 1980s. Coal-fired generation capacity rapidly expanded to fuel China's economic growth in the decade after 2000. It is a large driver of the rising emission levels. As shown in Figure 20, coal-fired power plants accounted for 63.7% of total installed capacity in 2014, with a total of 895.2 GW. While China continues to build coal-fired power plants, their share in the total installed capacity mix has been decreasing since 2007 (Enerdata, 2014a). This is in part due to increased investment in low-carbon sources of generation.

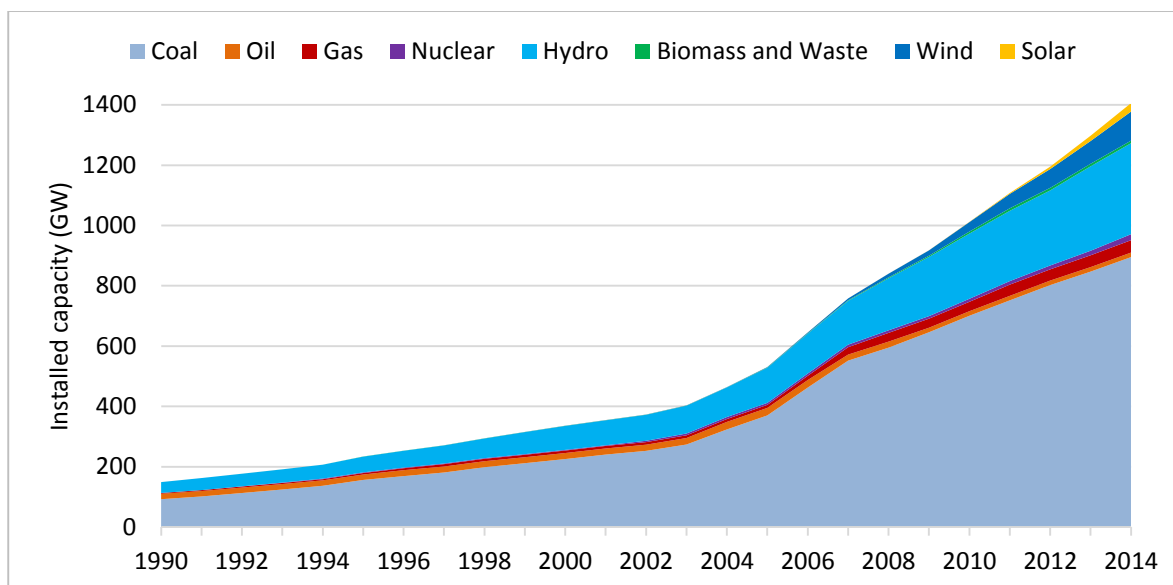


Figure 19: China's electricity generation by fuel, 1970-2014 (Enerdata, 2014a).

Total installed renewable capacity rose from 38.9 GW in 2010 to 133 GW in 2014, accounting for 9.46% (Enerdata, 2014a). In 2014, China was the world's largest investor in renewable energy, investing approximately US\$ 89.5 billion (The Climate Group, 2015). China has the highest annual installed capacity rate for wind power globally, accounting for 45% of new installations in 2014 (Enerdata, 2014d). An additional 9.1 GW of wind power capacity was installed in the first half of 2015, as well as 7.7 GW of solar capacity. According to government statistics, total installed wind power was 105.5 GW and solar power 35.8 GW in July 2015 (Enerdata, 2015d). This means that China has already surpassed its 12th FYP target of installing 100 GW of wind and 35 GW of solar power by 2015.

Installed hydroelectricity capacity increased from 79.4 GW in 2000 to 301.8 GW in 2014 (Enerdata, 2014a). China operates the world's largest hydropower dam, the Three Gorges Dam, which became operational in 2012. It is situated on the Yangtze River and has a total installed capacity of 22.5 GW. In 2014, the dam produced the highest annual generation from hydropower globally, at 99 TWh (EIA, 2015b).

Installed nuclear capacity has increased by a factor of 5 since 2000 (Enerdata, 2014a). In September 2015, 29 nuclear power reactors were operational in China with a total installed capacity of 25 GW (IAEA, 2015). This accounted for 1.4% of total installed capacity (Enerdata, 2014a). Nuclear power accounted for 2.4% of electricity generation in 2014.

As shown in Figure 20, the share of coal-fired generation is larger than its share of installed capacity. This is in part due to its role as a baseload provider. In 2014, the share of coal-fired generation dropped by 2% compared to 2013 (Enerdata, 2014a). Hydroelectric generation grew by 15.7%, in part due new capacity coming online, but also due to high levels of rainfall

(Dale, 2015). The decline in the demand for coal in the power sector affected the deceleration of the growth in Chinese coal demand outlined in previous sections.

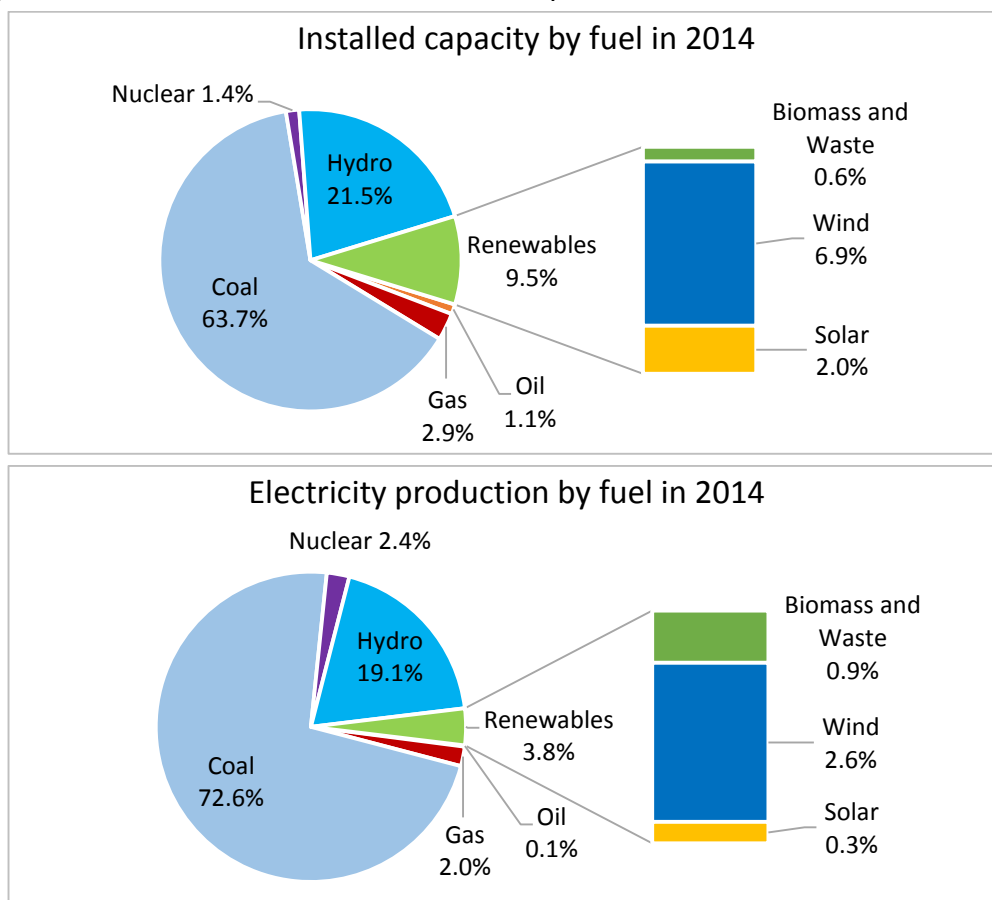


Figure 20: Comparison of installed capacity and electricity production in China for 2014 (Enerdata, 2014b).

Emission Intensity of Electricity

China's emission intensity of electricity generation is relatively high at 727 gCO₂/kWh (Enerdata, 2014a). This is due to the reliance on coal-fired generation. As Figure 21 shows, the carbon intensity of generation has been decreasing since 2003. From 2013 to 2014, carbon intensity of generation decreased by 4% (Enerdata, 2015e). This is likely due to the growth of the share of hydropower and renewable energy sources in the generation mix in 2014, as well as the slowing growth in coal-fired generation. Similarly, total power sector CO₂ emissions fell 0.2% from 2013 to 2014 (Enerdata, 2015e). This is likely due to an increase in low-carbon generation, especially hydropower in 2014, but also because of a decline in electricity demand from the industrial sector.

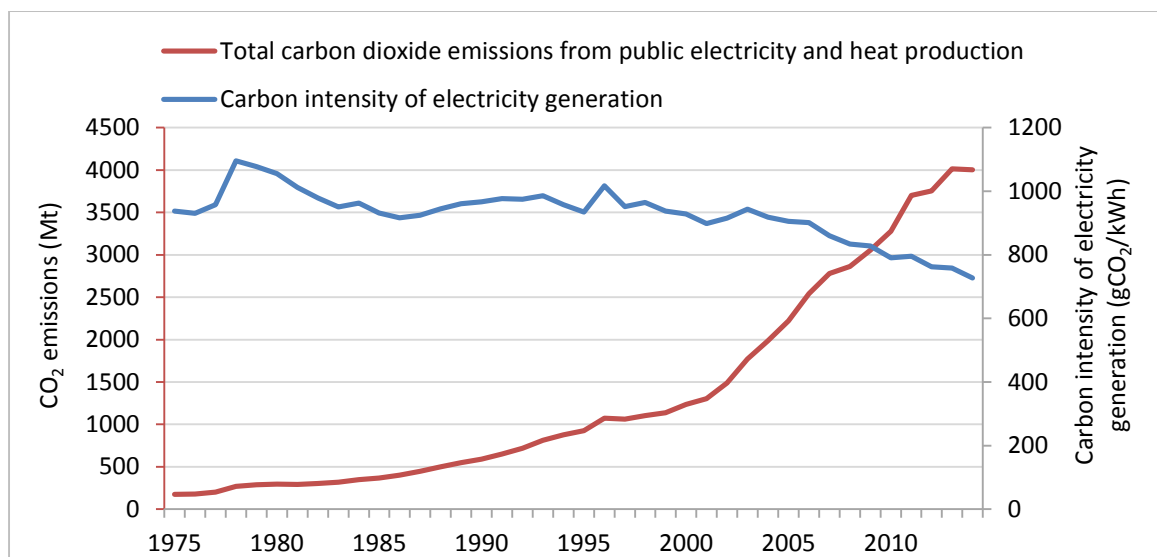


Figure 21: China's total CO₂ emissions and carbon intensity of electricity generation, 1975-2014 (Enerdata, 2014a).

5.5 Discussion and Analysis

The following section examines whether government capacity targets are likely to be reached in 2020. Scenarios developed by APEC will then be considered to determine whether their BaU scenario predicts a similar generation mix.

5.5.1 Government Projections

As China shifts away from heavy-industry, the government predicts that the electricity demand growth rate will fall. In 2010, electricity demand grew 13% (Enerdata, 2014a). By 2015, however, the government forecasts that electricity demand growth will be limited to 8% per year (Enerdata, 2014a). Although annual growth in electricity demand is decelerating, total electricity consumption continues to increase. For example, the NEA expects total consumption to rise to 5700 TWh in 2015, up from 5583 TWh in 2014 (Enerdata, 2015c; Enerdata, 2014a). China is investing in generation capacity to prevent shortages. According to the 12th FYP, investment in power plant construction should total RMB 2.75 trillion (equivalent to approximately US\$ 430bn) between 2011 and 2015 (KPMG, 2011). In 2014, China's total installed hydropower capacity (301.8 GW) was already greater than its 2015 target of 290 GW. The nation's wind and solar targets have also already been achieved. While the government's 2015 capacity targets have already been met, uncertainty remains regarding China's ability to meet its 2020 targets.

Coal-Fired Generation Capacity

Several coal-fired power plants are under construction in China, such as two ultra-supercritical power plants, Anqing 2 and Anqing 3, which are expected to add 2 GW of capacity to the grid between 2015 and 2016 (Enerdata, 2015b). A new 1 GW IGCC project is being developed in Inner Mongolia by the China Energy Conservation and Environmental Protection Group and

Seamwell International (Enerdata, 2015b). A 2 GW supercritical plant is expected to be commissioned in 2015 (Enerdata, 2015b).

As the government aims to reduce coal to 62% of the primary energy mix by 2020, the share of coal-fired generation is expected to fall. As outlined, the Chinese government has implemented several policies to curb the use of coal in power generation and improve the efficiency of coal-fired generation. However, uncertainties regarding the effect these policies will have on emission levels remain. For one, China has not indicated how many coal-fired power plants it intends to construct until 2030. Coal-fired power plants are still being constructed further away from electricity demand centres and closer to coal-producing centres, as these areas do not fall under the ban (EIA, 2015a). Furthermore, as the majority of China's coal-fired generation capacity has been constructed after 2000, and is likely to be operational for the upcoming decades. Thus, while the share of coal-fired capacity in the electricity mix is decreasing, the size of its current fleet, as well as the number of plants under construction indicate that coal will remain the dominant fuel in power generation.

Recognising the need to reduce emissions, and driven by a desire to limit pollution levels, the government has become increasingly interested in CCS. Alongside domestic R&D projects, the government is collaborating with the EU and US on clean coal initiatives. The US-China Bilateral Statement on Climate Change, for example, emphasised the importance of joint action to encourage CCS research and demonstration (The White House, 2014). China is planning to build one IGCC plant that is 'capture ready' in Tianjin, and a combined heat and power (CHP) plant with post-combustion CO₂ capture is being constructed in partnership with the Australian research centre CSIRO (Enerdata, 2015b). If this technology develops further, it has the potential to significantly impact Chinese power sector emissions.

Gas-Fired Generation Capacity

According to the Energy Development Strategy Plan, the share of natural gas in the primary energy mix should increase to 10% by 2020 (LSE, 2015). Gas is seen as a cleaner source of electricity, as evidenced by the construction of gas-fired power plants to replace coal-fired capacity in the main city clusters. Shutting down coal-fired power plants in Beijing alone could lead to a 30 Mt CO₂ emission reduction (Bloomberg Business, 2015). Several gas-fired power stations were planned and under construction in China in 2015. This includes a 700 MW project under development by the Shaanxi Provincial Investment Group (Enerdata, 2015b).

China's ability to replace coal-fired generation with gas-fired capacity depends on the nation's ability to enhance domestic natural gas production, and improve import infrastructure. China has large natural gas reserves. The government aims to produce 6.5 Tcf of natural gas by 2020 (EIA, 2015a). Natural gas consumption in 2013 was already 5.7 Tcf, and projected to rise as the government continues its policy of replacing coal with gas (EIA, 2015a). Imports are thus likely to play a large role in satisfying natural gas consumption by 2020. China is investing in new LNG terminals, as well as developing import pipelines to satisfy domestic

demand (Enerdata, 2015b). It is likely that China will be increasingly dependent on foreign supply of energy. This runs counter to China's aim to be 85% energy self-sufficient by 2020 (LSE, 2015).

Nuclear Power Generation Capacity

In September 2015, 30 nuclear projects with a total generation capacity of 23 GW were under construction, doubling current installed nuclear generation capacity to 48.7 GW by 2020 (Enerdata, 2015b; IAEA, 2015). This represents more than one-third of total global nuclear capacity under construction (EIA, 2015a). This includes the Fuqing Project, which will consist of four 1 GW reactors. Fuqing 1 and Fuqing 2 are already operational, and the remaining two plants are expected to be commissioned between 2015 and 2017 (Enerdata, 2015b). The majority of these nuclear plants are pressurised water reactors (IAEA, 2015).

Although 30 nuclear projects are under construction, it is unclear whether the government's nuclear capacity target of 58 GW by 2020 will be met. China temporarily froze the approval of nuclear projects following the Fukushima accident in 2011, and only two nuclear reactors have been approved since the temporary ban was lifted in 2012 (Enerdata, 2015b). Due to the time it takes to construct a nuclear power plant, it is likely that installed nuclear capacity will be limited to generation from projects currently under construction, at around 48.7 GW. After 2020, however, it is likely that China's nuclear fleet keeps expanding as the government plans to have an additional 30 GW of nuclear power under construction (EIA, 2015a).

Hydropower

In 2015, a 2.5 GW hydropower plant developed by the Yunnan Jinsha Hydropower Development Co. is expected to be commissioned (Enerdata, 2015b). Between 2016 and 2018, two hydroelectric plants totalling 7.6 GW are expected to come online (Enerdata, 2015b). China's economically exploitable hydro capacity is 404 GW. Thus, the target 2020 target of installing 420 GW seems to assume that technological development will reduce the cost of hydropower. However, the ability to exploit China's theoretical capacity is constrained by environmental concerns, social opposition, and geographical considerations. The majority of this capacity is situated in the south-western regions of the country, where the ecological system is fragile, increasing the cost of hydropower construction (Hu et al., 2014). As these areas are further way from electricity demand centres, exploiting this hydropower potential would require investment in transmission infrastructure. Furthermore, the rivers identified flow into different countries, and could thus increase conflict with neighbouring nations (Watts, 2010). Thus, it seems highly unlikely that China could exploit the entirety of its 'theoretical capacity' in the future.

Renewable Energy Sources

In 2015, 8 GW of wind and solar projects were under construction and a further 7 GW had been approved by local authorities (Enerdata, 2015b). The majority of new wind projects are being constructed in Inner Mongolia, which has a high wind energy potential. As Figure 22

shows, Inner Mongolia already has the largest installed capacity nationally. By 2015, 30 GW of wind power is expected to be installed in the province, rising to 50 GW in 2020 (Enerdata, 2015b).

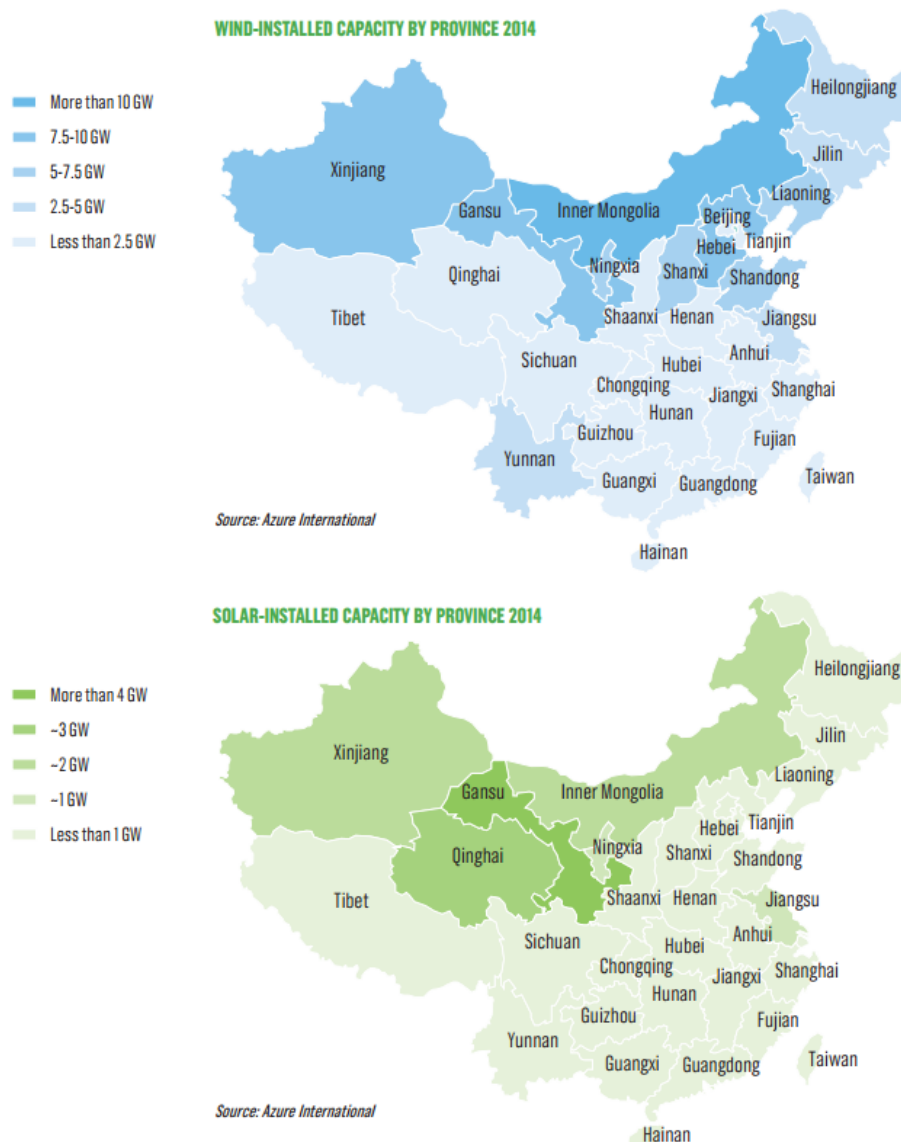


Figure 22: China's wind- and solar-installed capacity by province, 2014 (The Climate Group, 2015).

Generation from renewable energy sources faces several constraints in China. In 2014, generation from renewable energy sources was only 3.8% (Enerdata, 2014a). This is caused by two key factors. First, a lack of transmission capacity prevents renewable energy sources to be connected to the grid. As Figure 22 shows, wind- and solar-installations are concentrated in the northern and north-western provinces. While these have good renewable energy potential, they are relatively sparsely populated and removed from the electricity demand centres in the east (The Climate Group, 2015). Furthermore, while subsidies are provided to the construction of renewable energy sources of generation, the construction of transmission lines to connect wind and solar farms to the grid is currently not subsidised (Campbell, 2014). In 2011, approximately one-third of installed wind capacity was not connected to the grid

(Fridley et al., 2013). Grid connection was improved in 2013, and the share of wind capacity not connected to the grid decreased to 16% (IEA Wind, 2014).

Fridley et al. (2013) found that renewable energy sources (including hydropower) could account for as much as 30.1% of electricity generation by 2020 if the transmission grid was strengthened and operating efficiently, which would decrease system CO₂ emissions by 7.7%. This share decreased to 23.7% (with 18% from hydropower) in 2020 under current grid bottlenecks, increasing system CO₂ emissions by 1.3% (Fridley et al., 2013). Thus, investment in the Chinese transmission grid is a key factor influencing the generation mix, which in turn influences emission levels.

Secondly, while China's Renewable Energy Law mandates that grid companies must purchase generation from renewable energy sources, this is not always implemented at the provincial level (Campbell, 2014; GWEC, 2015). Thus, even when renewable capacity is connected to the grid, it is often curtailed. Coal-fired power plants are often given priority access to the grid to recover investment and cost at a local level (Burnard et al., 2014). Thermal plants with the lowest operating costs are often given priority. This can lead to higher emission and pollution levels, as these are not always the most efficient plants (Burnard et al., 2014). The national government is expected to introduce a Renewable Energy Portfolio Standard in 2015 to ensure that generation from renewable energy sources is given priority access to the grid (GWEC, 2015). Until this standard is introduced and the transmission grid is expanded, it is likely that the renewable energy generation will remain constrained.

Implications for Emission Levels

China has stated that it will peak emissions by 2030. The government has not, however, provided an absolute emission level, or indicated the expected emission level of the power sector. This makes it challenging to determine the level of emissions from the power sector.

The shift from coal-fired generation to low-carbon sources such as nuclear, hydropower and renewable energy has the potential to reduce carbon intensity of the power sector. The promotion of gas-fired generation could also result in lower emissions if it replaces coal-fired capacity. As seen previously in Figure 21, the carbon intensity of electricity (CO₂/kWh) has been declining since 2003. Although it is likely that China will continue to construct coal-fired generation capacity towards 2030, new plants are mandated to use supercritical or ultra-supercritical technology. This will likely increase the efficiency of coal-fired generation capacity and has the potential to reduce carbon intensity of electricity further (Green & Stern, 2015). Electricity demand growth is predicted to be lower than in previous years, due to a decline in heavy-industry. Considering these factors, it is possible that emissions in China's power sector rise at a slower rate than what was seen from 2000-2009. If these trends continue and China implements further policies (for example, in its 13th FYP) to encourage efficiency and low-carbon generation, emissions from the power sector could plateau towards 2030 (Green & Stern, 2015).

5.5.2 APERC Scenarios

The Asia Pacific Energy Research Centre developed the same Business-as-Usual and High Gas scenarios for China. Under both scenarios, China's energy consumption is expected to grow 2.3% annually from 2010 to 2035 (APERC, 2013b). Energy demand from the industrial sector is expected to slow to 0.9% (compared to an annual average growth rate of 5.6% between 1990 and 2009) in line with the restructuring of China's economy. The demand for electricity in industry is expected to rise, accounting for 34% of industry energy demand in 2035. Electricity generation is expected to rise 3.3% annually from 2010 to 2035 (APERC, 2013b).

APERC's prediction for 2015 differs from the targets set by the government. If the targets outlined in the 12th FYP are met in 2015, 63% of installed capacity will be from coal-fired power stations. APERC's scenario predicts a lower share, at 61% in 2015. While APERC's BaU scenario predicts that installed coal-fired capacity will be 772 GW in 2015, Enerdata statistics indicate that 895 GW of coal-fired generation was already installed in 2014 (Enerdata, 2015b; APERC, 2013b). APERC's projections for 2020 is 841 GW, and thus remain lower than current installed capacity (APERC, 2013b). This indicates that installation rates for coal-fired capacity are higher in China than APERC assumes.

APERC's projections regarding installed nuclear capacity are consistent with government targets. APERC predicts 32.8 GW of nuclear installed capacity by 2015, rising to 58 GW in 2020 and 96 GW in 2030 (APERC, 2013b). However, it is unlikely that the 2015 or 2020 projection will be realised, due to stricter nuclear planning approval processes following the Fukushima accident. It is possible, however, that the 2030 projection is met, if the government approves further nuclear projects in upcoming years.

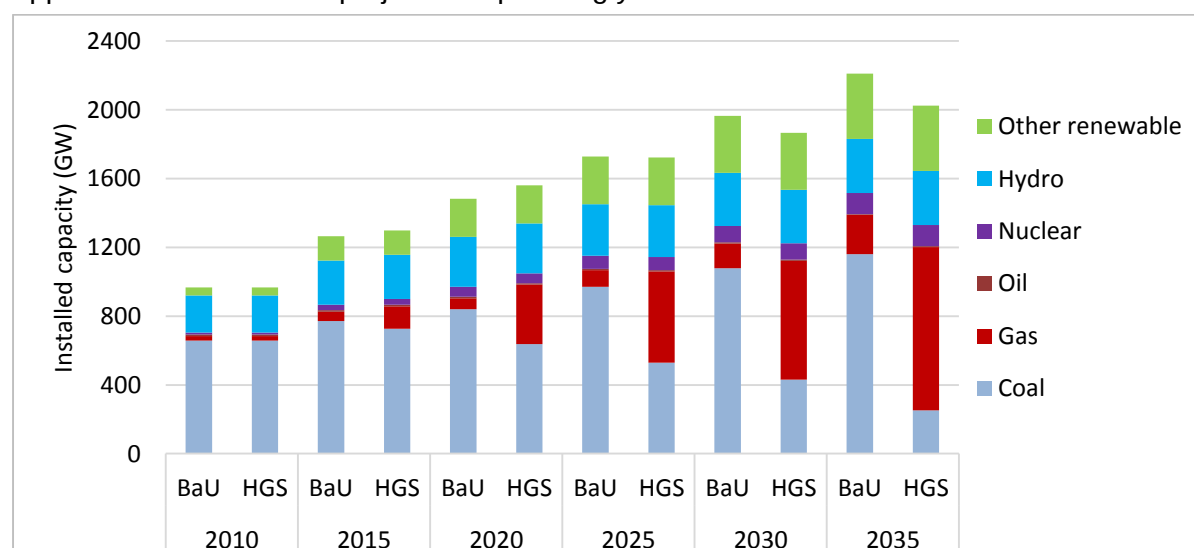


Figure 23: APERC scenario comparison of electricity generation capacity in China, 2010-2035 (APERC, 2013b).

As Figure 23 shows, APERC's BaU scenario predicts that hydropower capacity remains relatively stable from 2015 to 2035. This is inconsistent with government plans to increase the share of hydropower capacity in the generation mix. Furthermore, Enerdata indicates that installed hydropower capacity in 2014 was 302 GW, which is higher than APERC's expectation for 2025 (301 GW). This seems to indicate that APERC's scenarios and assumptions are out of date. APERC predicts that installed hydropower capacity rises to 313 GW in 2035 (APERC, 2013b). Given that 10 GW of hydropower is already under construction and expected to be commissioned before 2018, it is highly likely that China's 2035 actual installed hydropower capacity will be higher than APERC's prediction.

APERC's HG scenario assumes that China overcomes technical and political challenges to develop its shale gas resources. This leads to a 28% increase in gas production compared to the BaU scenario (APERC, 2013b). Furthermore, the HG scenario assumes that additional pipelines and LNG ports will be constructed to increase imports of natural gas. The increase in natural gas production does not have an impact on the amount of projected installed renewable energy capacity, nuclear capacity, or hydro capacity. As can be seen in Figure 23 however, coal-fired installed capacity falls in comparison to the BaU scenario, while that of gas-fired generation rises. Installed coal-fired generation capacity falls to 251 GW by 2035, accounting for 12% of installed capacity under the HG scenario, while gas-fired generation rises to 950 GW and accounts for 46% (APERC, 2013b).

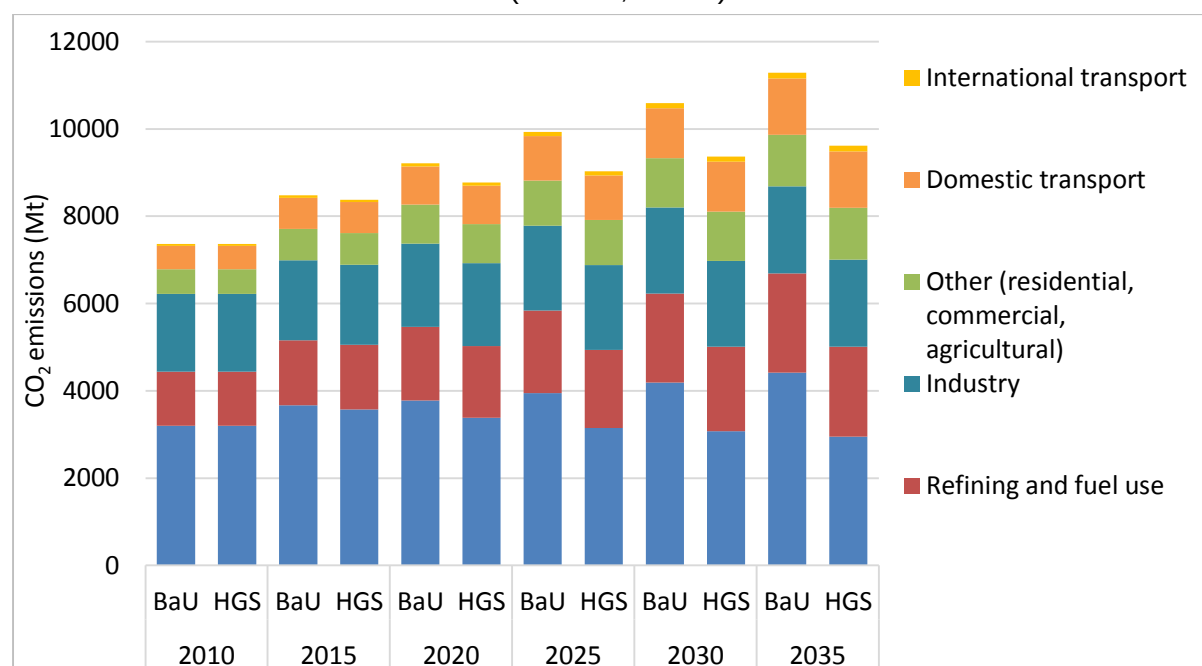


Figure 24: APERC scenario comparison of sectorial emissions in China, 2010-2035 (APERC, 2013b).

Figure 24 shows emissions by sector under APERC's two scenarios. As shown, the increase of gas-fired generation under the HG scenario reduces emissions from the power sector, as it reduces the carbon intensity of electricity production (APERC, 2013b). The HG scenario predicts that CO₂ emissions decline by 33% from 2010 to 2035. Given that the Chinese

government intends to increase the share of gas in primary energy demand, it is likely that gas-fired generation will increase towards 2035. However, it is unlikely that the rates of installed capacity envisaged in APERC's HG scenario will be achieved. The HG scenario predicted that gas-fired installed capacity would reach 131 GW in 2015 (APERC, 2013b). In 2014, installed capacity was 41 GW, which the government aimed to increase to 56 GW in 2015 (Enerdata, 2015e). Unless the technological improvements assumed for the HG scenario occur, it is unlikely that emissions from the power sector will reduce like the HG scenario predicts.

Implications for Carbon Intensity

Under the APERC BaU scenario, economic growth is decoupled from CO₂ emissions. China's CO₂ intensity of the economy is projected to decline 0.8% on average annually from 2010 to 2035. This is due to energy efficiency measures, a reduction in coal-fired generation as well as a reduced demand for coal in other industries, and a shift away from energy-intensive industries (APERC, 2013b). APERC's BaU predicts that CO₂ emissions per unit of GDP declines by 34% in 2015 compared to 2005 levels, 43.4% by 2020, and 50% by 2030 (APERC, 2013b). According to government statistics published by the State Council, the energy intensity of China's economy declined 3.7% from 2012 to 2013, and 4.8% from 2013 to 2014 (Enerdata, 2015e). This was attributed to declining coal consumption, low growth rates in power generation, the closure of several inefficient steel and cement production, and a restructuring away from heavy industry (Enerdata, 2015e). China is thus making progress towards meeting its target.

APERC's 2020 projection is consistent with the government target of reducing carbon intensity 40-45% below 2005 by 2020. If the intensity targets outlined in the 12th FYP are achieved by 2015, a CO₂ intensity target of at least 15-16% during the 13th FYP is necessary to meet the upper limit of this pledge (Da, Zhiwei & Jiankun, 2012). This may be difficult to achieve solely through energy efficiency measures, as many of the inefficient thermal plants, steel mills, and coalmines are already shut down (Campbell, 2014). Thus, it is likely that a continued increase in low-carbon generation is necessary to meet their 2020 pledge. APERC's 2030 forecast is lower than the government target of a 60-65% reduction below 2005 levels. Determining whether the government is likely to reach this target involves the analysis of the entire energy system, which is outside the scope of this paper. However, the carbon intensity of electricity is likely to decline. As the power sector accounted for 46% of energy-related CO₂ emissions in 2014, this would have a significant impact on the reduction of the carbon intensity of GDP.

5.5.3 Enerdata Scenarios

Enerdata have developed a POLES partial equilibrium simulation model of the energy sector for projecting energy scenarios for various countries. There are three scenarios: Balance, Emergence and Renaissance. The Balance Scenario is the BaU reference case based on current policies and trends. The Renaissance Scenario explores the impacts of enhanced

exploration and production of unconventional fossil fuels and limited implementation of climate policies. The Emergence Scenario assumes that international agreements on climate change are reached and that new more stringent policies are enacted so as to limit the global temperature increase to 2°C.

Figure 25 displays China's installed generation capacity according to the APERC scenarios, government capacity targets, as well as Enerdata scenarios. As outlined, APERC's HG scenario predicts a higher share of gas-fired generation towards 2035 than the BaU scenario. The scenarios predict similar levels of installed hydropower, nuclear power, and renewable energy capacity. As Figure 25 does not differentiate between thermal sources of capacity, both scenarios are plotted as one.

As shown, Enerdata's Balance and Emergence scenarios predict a higher share of firm low carbon and intermittent renewables in the electricity mix than Enerdata's Renaissance scenario and APERC's scenarios. APERC's BaU scenario predicts a different installed capacity mix than Enerdata's BaU scenario (the Balance scenario). This indicates that there is a discrepancy between business-as-usual projections from different sources. It is likely that this is due to different assumptions made by APERC and Enerdata regarding the future state of the electricity system, technological costs, and innovation. Enerdata's scenarios will now be examined in detail.

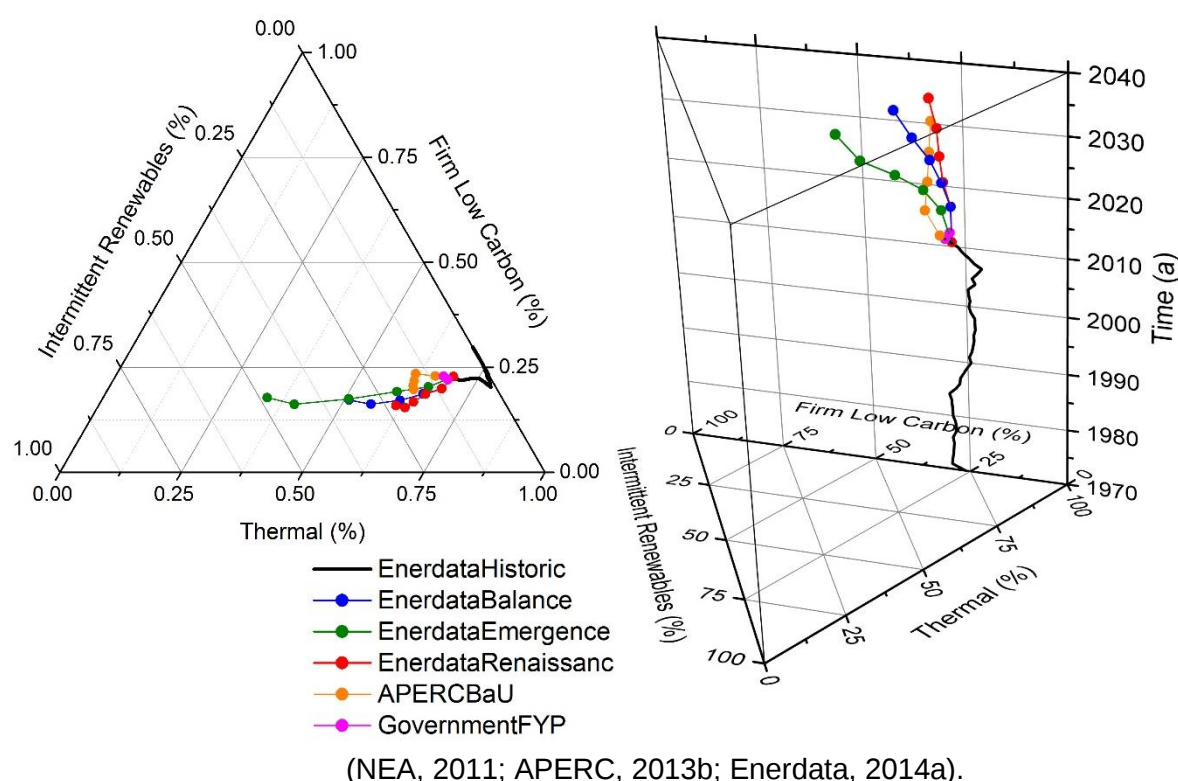


Figure 26 displays China's installed capacity towards 2040 according to the three different Enerdata scenarios. Balance and Renaissance have almost identical installed capacity towards 2020. In these scenarios, thermal capacity is expected to total 1500 GW, nuclear

capacity 71 GW, hydropower 363 GW, and total installed renewable capacity approximately 250 GW. Emergence predicts a higher share of nuclear capacity, with 90 GW installed by 2020, and greater installed renewable energy capacity, at 310 GW (Enerdata, 2014a). As the government aims to install 60-70 GW of nuclear capacity and 250 GW of renewable energy by 2020, government targets most closely align with the Balance and Renaissance scenarios towards 2020.

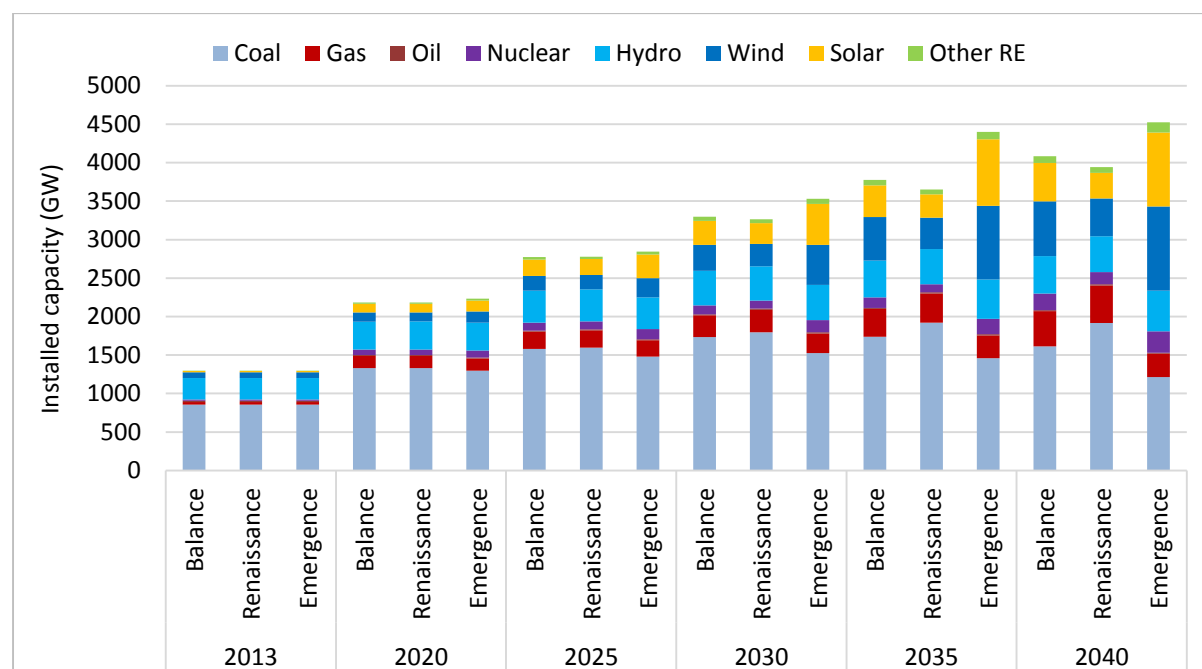


Figure 26: Enerdata scenario comparison of China's installed capacity towards 2040 (Enerdata, 2014a).

Emergence predicts the largest decline in thermal-fired generation towards 2040. Under the Emergence scenario, China's total installed hydropower capacity approaches 527 GW (Enerdata, 2014a). Thus, it seems to assume that China overcomes technical and social difficulties to utilise its technical exploitable hydropower capacity. All Enerdata scenarios predict higher installed hydropower capacity than the APERC projections. As the government has traditionally viewed hydropower as a reliable low-carbon source of generation and is still planning on constructing large-scale hydropower plants, it is likely that hydropower capacity increases towards 2040.

As shown in Figure 26 Emergence and Balance forecast that coal-fired generation capacity declines after 2030. This seems consistent with government announcements that no new coal-fired power plants will be constructed after this date. Both scenarios predict an increase in gas-fired generation. This is also likely to occur, as the government intends to increase the share of gas-fired capacity in the electricity system. Under Emergence, however, approximately 43% of installed capacity in 2040 is from renewable energy sources. Balance predicts a smaller share at 32%, while renewable energy sources account for 23% of installed capacity in the Renaissance scenario (Enerdata, 2014a).

These different projections regarding installed capacities have a significant impact on emission levels towards 2040, as displayed in Figure 27. As shown, power sector emissions are expected to stabilise under the Balance scenario. As outlined, China's current shift to low-carbon generation, promotion of gas-fired generation, and energy efficiency standards for coal-fired capacity makes it possible that power sector emissions stabilise towards 2030. Balance predicts power sector emission levels will decline after 2035, resulting in an overall decrease in economy-wide emissions. Power sector emissions decline after 2028 under the Emergence scenario, causing total emissions to decrease (Enerdata, 2014a). This decline highlights the emission abatement potential of the power sector towards 2040. Furthermore, it displays the impact that reducing emissions in the power sector would have on the nation's total carbon dioxide emissions.

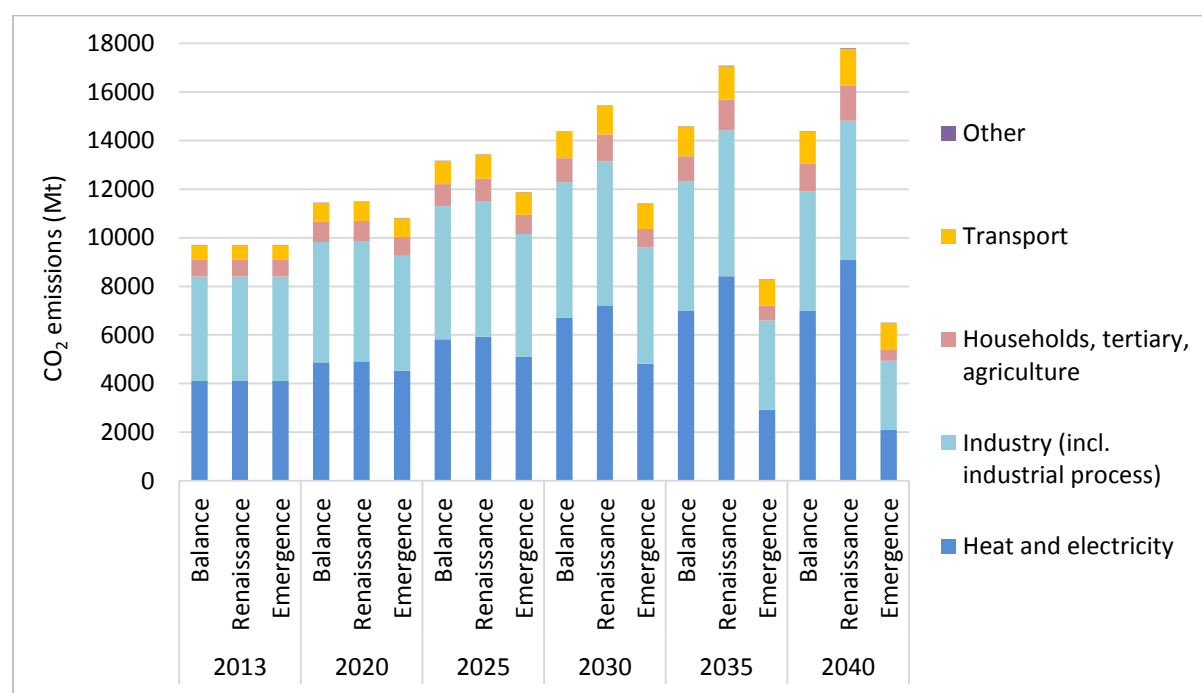


Figure 27: Enerdata scenario comparison of sectoral emissions in China towards 2040 (Enerdata, 2014a).

5.6 Summary

China's new development path stresses the need for more sustainable and high quality economic growth. This has been translated into three key objectives in the energy sector: increasing energy efficiency, reducing environmental degradation and air pollution, and increasing the share of low carbon energy generation. The government is also promoting a shift away from heavy-industry in favour of growth in the service sector. As a result, electricity demand growth is projected to slow as demand from energy-intensive industries declines. Although demand growth is expected to decline, total demand will likely continue rising. Thus, new capacity is necessary to prevent shortages.

The power sector is one of the largest consumers of coal in China, and so the government's intention to cap total coal consumption to 62% of primary energy will have a large impact on

future installation capacity rates. However, it is unclear how many coal-fired power stations China intends to build towards 2030. Regulations mandating that all new-build power stations have to use supercritical or ultra-critical technology have the potential to significantly influence the carbon intensity of the power sector. Furthermore, if China employs CCS technology, CO₂ emission levels from the power sector could stabilise or even fall. Due to the size of currently installed coal-fired capacity, and large domestic coal reserves, it seems that coal will continue to be the dominant fuel in China's electricity mix.

While the carbon intensity of the electricity sector seems to be declining, it is unclear whether it is enough to contribute significantly to a China's overarching carbon intensity target. As inefficient thermal capacity has already been taken off the grid, further reductions in carbon intensity need to come from additional measures other than energy efficiency. This will require large installations of low-carbon generation and the use of CCS. As China's nuclear plans are slowing and facing stricter regulation, its renewable energy sources are facing grid constraints, and its hydropower potential is constrained by ecological considerations and social opposition, there is uncertainty regarding the future growth rate of low-carbon generation in China. Furthermore, it is important to note that as China's targets are intensity targets, reaching these targets does not necessarily translate into a reduction in total emission levels. Intensity targets do not restrict emissions to a certain level, but allow emissions to rise alongside GDP. Thus, while total power sector CO₂ emissions fell by 0.2% in 2014, it is unclear whether this is likely to continue.

There are real difficulties in determining what China is actually installing. To the author's knowledge, there seems to be no comprehensive database of China's planned or approved power plant projects. This makes it challenging to make conclusions about whether China is reaching its targets, as data is gathered from many different reports and newspaper articles. There is a need for increased reporting of projects under construction, and longer term planning regarding the number of thermal power plants that will be built.

Finally, the government intends to reduce public-investment in favour of private sector investment. This involves a restructuring of State Owned Enterprises and a gradual increase in the role of the market in the electricity sector. This provides an interesting point for further research. There is a question of how set targets will be met without government interference and investment. It is likely that additional incentives will be necessary to encourage private sector investment in the electricity sector and low-carbon sources of generation in particular.

6 INDIA

Highlights:

- Increasing the provision of electricity is a primary concern for India, as 25% of the population have no access to electricity. However, even those with access have an intermittent and poor quality supply of power. On average, 15-18% of peak demand is currently not met leading to frequent blackouts.
- India has substantial coal reserves but domestic production cannot keep up with the increasing demand for power. India has a three stage nuclear strategy aiming to utilise its large thorium reserves and enhance energy security.
- There is a voluntary carbon intensity goal of reducing CO₂ emissions per unit of GDP by 20-25% below 2005 levels by 2020.
- The carbon intensity of electricity generation is the highest in the world at 964 gCO₂/kWh (average for Europe being 294 gCO₂/kWh).
- Renewable capacity in India has grown significantly from 1.2 GW in 2000 to 31.7 GW in 2014 (predominantly wind), mainly driven by state level policies e.g. Tamil Nadu (southern state).
- Inadequate transmission and distribution (T&D) infrastructure is a major barrier to increasing renewable deployment. The T&D losses from the electricity networks are very high with estimates between 23-30%.
- There is a long term ambition to increase percentage of nuclear, hydropower and renewable capacity although vastly differing capacity targets creates ambiguous environment for investors.
- Federal system of governance with the state governments having strong influence on energy policies makes it difficult to coordinate effective action within the electricity sector.

6.1 Background

India consists of 29 states and seven union territories with a democratic federal republic system of governance (CIA, 2015c). India has the 2nd largest population in the world at 1.25 billion, which has been expanding at an annual rate of 1.3% over the last five years (WB, 2015a). Major economic reforms initiated in the 1990s, most notably the 'New Economic Policy' in 1991, stimulated growth in the Indian economy after years of stagnation and led to a 7% growth rate that has been sustained since 2000 (IEA, 2012). India's GDP in 2014 was US\$ 2.1 trillion and there is an on-going shift towards a free market economy with the privatisation and deregulation of state-owned enterprises (WB, 2015a).

The pressure on India's energy system has been building steadily as a result of both the rapidly increasing population and their growing economy. Energy demand in India has more than doubled since 1990 and has led to India being the 4th largest consumer of primary energy in the world after China, the USA and Russia (BP, 2015). The International Energy Agency (IEA) has predicted that from 2025-2040, India will overtake China as the dominant force behind increasing global energy demand (IEA, 2014b).

Development goals are a high priority for the Indian government as a large proportion of the population still lack access to health care, education, clean cooking fuels and electricity. The

number of people living on less than US\$ 1.25 per day was estimated to be 288 million in 2011 (WB, 2015a). One of the key issues facing India's energy system is the low level of electrification in the rural areas of the country. It is estimated that 25% of the population have no access to electricity and even those with access have an intermittent and poor quality supply of power (TERI, 2015). Indian policy makers face the huge challenge of meeting their development objectives whilst constraining potential environmental impacts, ecosystem degradation and carbon emissions.

6.1.1 Emissions

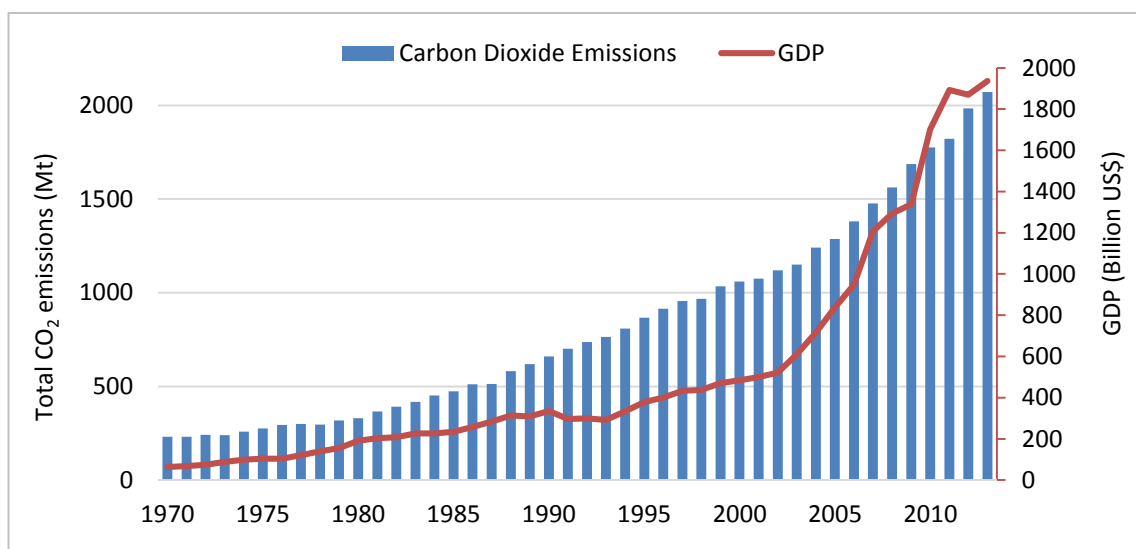


Figure 28: Total CO₂ emissions in India (EDGAR, 2014) and current GDP (Enerdata, 2014a) from 1970 to 2013.

Figure 28 indicates that India's CO₂ emissions have increased dramatically since 1970 and there has been a particular acceleration in emissions over the last 15 years, associated with the rapid increase in GDP. CO₂ emissions doubled between 2000 and 2013 reaching 2072 MtCO₂, representing 5.9% of the global total. According to the EDGAR database, India has the 3rd largest emissions globally of both CO₂ and total greenhouse gases (EDGAR, 2014). However, in terms of per capita emissions, India is still well below the global average due to its large population.

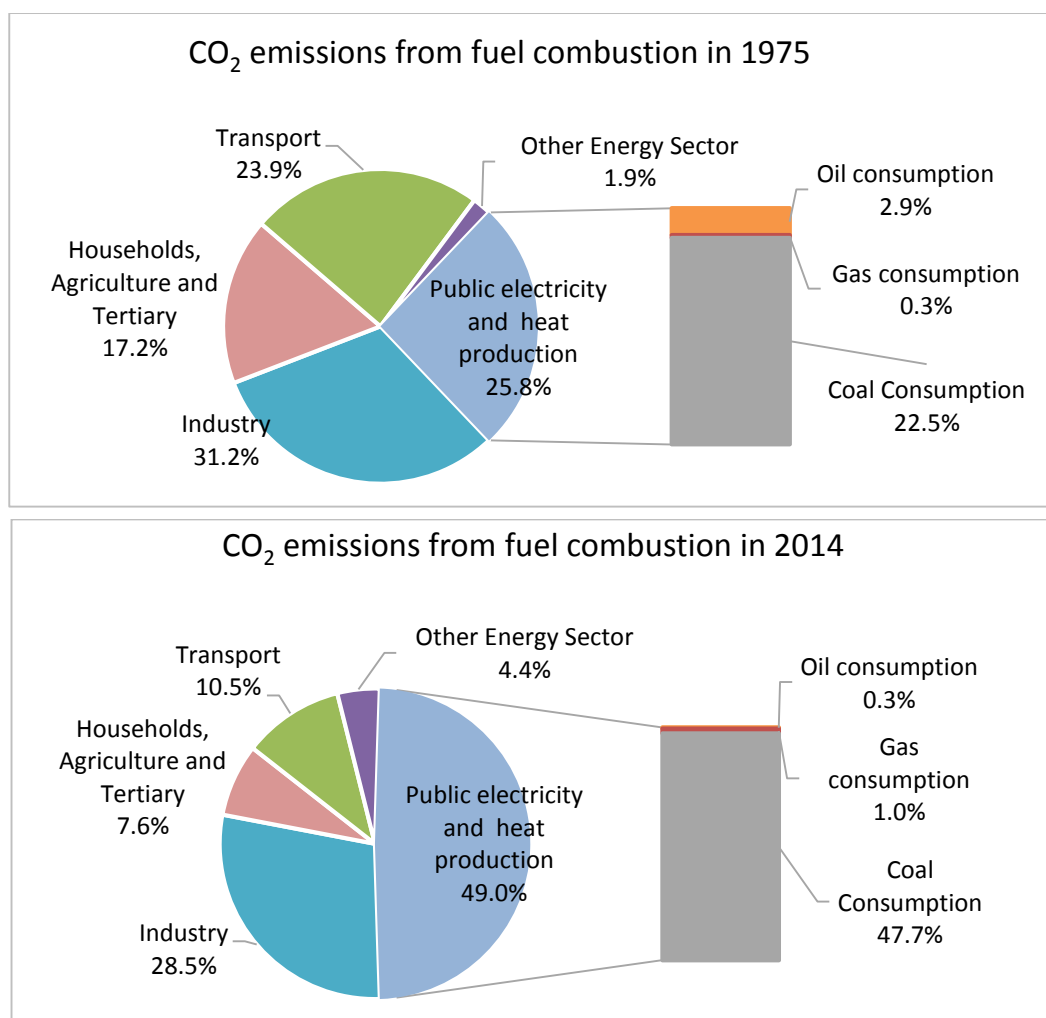


Figure 29: Comparison of CO₂ emissions by sector for India in 1975 and 2014. ‘Other energy sector’ refers to emissions from refining and fugitive sources (Enerdata, 2014a).

It can be observed from Figure 29 that in 1975, industry and transport were important sectors in contributing to overall CO₂ emissions from fuel combustion. Public electricity and heat production accounted for 26%. Industrialisation and rapid population expansion has led to a dramatic increase in demand for electricity and this sector now contributes nearly half of total emissions in 2014, dominated by coal consumption.

6.1.2 Climate Change Targets

India is a signatory to the UNFCCC and has pledged its support for the Durban Platform on enhanced cooperation but has no legally binding targets to reduce CO₂ emissions (Gambhir et al., 2012). Instead, there is a carbon intensity goal of reducing CO₂ emissions per unit of GDP by 20-25% below 2005 levels by 2020 (MEFCC, 2008). If India manages to reach this target, 500 million tonnes of CO₂ could be saved each year (Hirst et al., 2012). However, it is very important to consider India’s absolute CO₂ emissions as these will continue to increase even if the target is met.

The change in emissions intensity of GDP is shown in Figure 30 and it can be observed that over the period 1995-2013, the emissions intensity of GDP decreased at an average rate of 0.9% each year. If the rate of emissions decrease is taken from the baseline year of 2005 to 2013, there is a 0.2% average decrease each year. Projections of future decreases in emissions intensity using these two rates of decrease are shown in Figure 30. The projection using the fastest rate of decrease exhibited over the historical period is also shown for comparison and it can be observed that none of these decrease rates manage to meet the target by 2020.

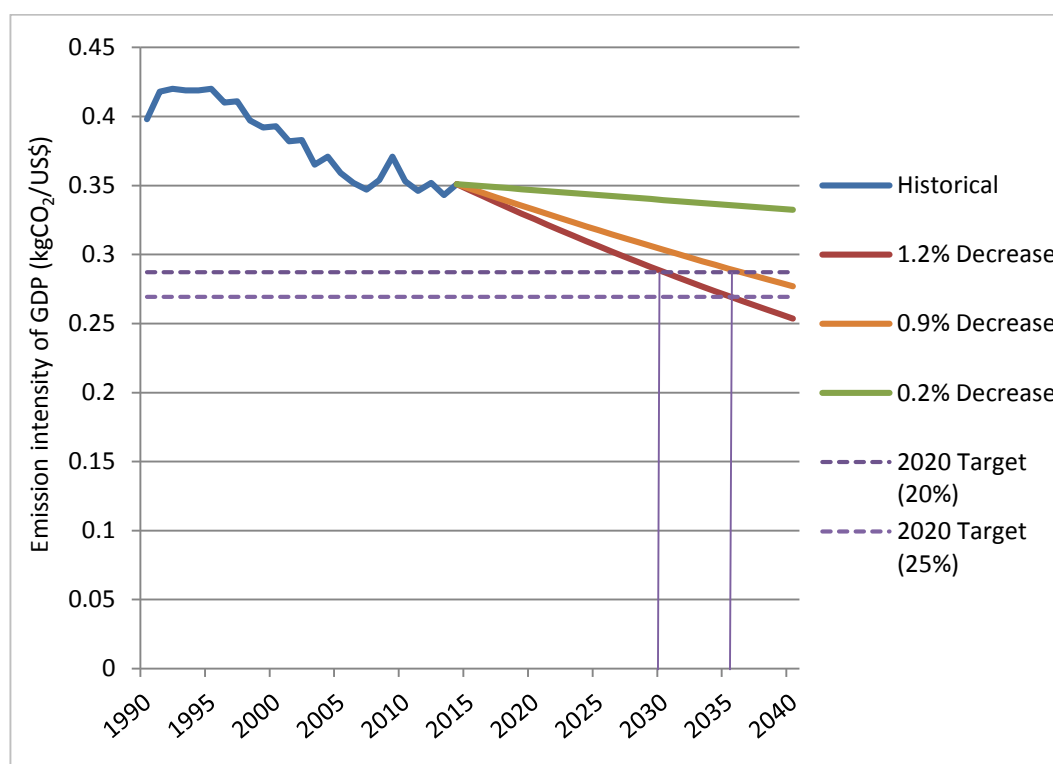


Figure 30: Historical emission intensity from 1990-2014 (Enerdata, 2014a). Three potential reduction pathways for future emission intensity are shown, along with the 2020 targets.

6.2 India's Electricity System

India has the third largest installed capacity in the world after China and the USA. The power sector has grown rapidly and electricity production has quadrupled from 293 TWh in 1990 to 1296 TWh in 2014 (Enerdata, 2014a). The industrial sector is the largest consumer of electricity accounting for 44% of total consumption, followed by the domestic and agricultural sectors that consume 22% and 18% respectively (CSO, 2015). Consumption of electricity in the agricultural sector is heavily subsidised (Enerdata, 2015f).

6.2.1 The Electricity Market

Until the 1990's, the electricity market was vertically integrated with each state electricity board (SEB) controlling generation, transmission and distribution within each region. Deregulation policies and power sector reform measures started to attempt the introduction of competition

into the power sector with the influx of private investment throughout the early 1990's. However, the market is still not nearly competitive.

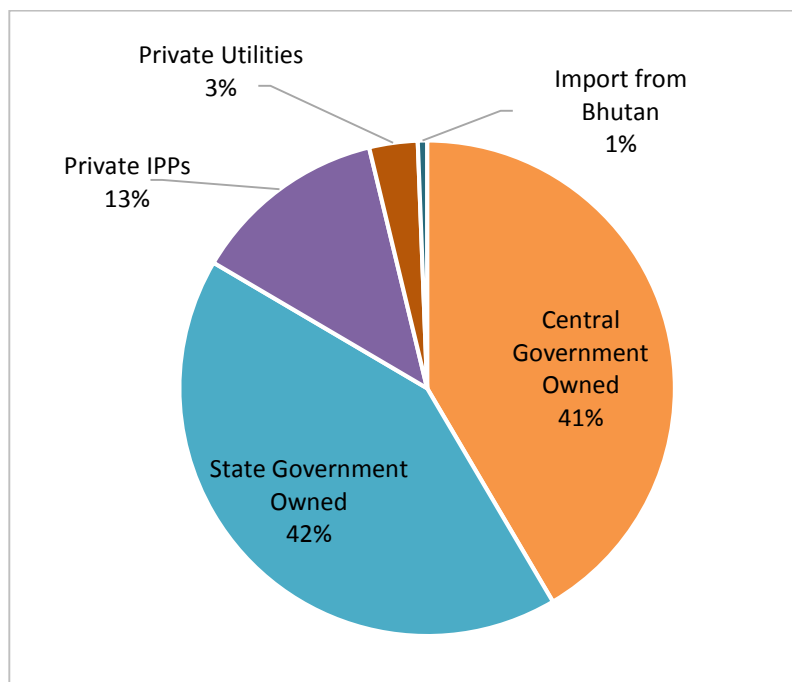


Figure 31: Sector wise share of electricity generation (CEA, 2012b)

Figure 31 indicates that in 2012, the state governments generated 42% of total electricity, central government owned capacity generated 41% and the private sector accounted for 16% (CEA, 2012b). The largest power generation company is the state-owned National Thermal Power Corporation (NTPC) (IEA, 2012). Main private companies include Adani Power, Tata Power, Essar Energy, Reliance and JSW Energy (Enerdata, 2015f). The introduction of the Electricity Act in 2003 initiated the unbundling of the SEBs within states. 18 states have now restructured their SEBs into separate production and distribution companies. There are now individual State Electricity Regulatory Commissions (SERCs) that regulate distribution at the state level (Enerdata, 2015f).

The centrally owned company 'PowerGrid India' operates the five regional transmission networks throughout the country, which can be observed in Figure 32. These networks were connected with 500 kV HVDC inter-regional lines as of December 2013, to facilitate the transfer of power to centres of high demand (PowerGrid, 2015). The Central Electricity Regulatory Commission (CERC) is the central regulator and sets the tariffs for inter-state generation and transmission.

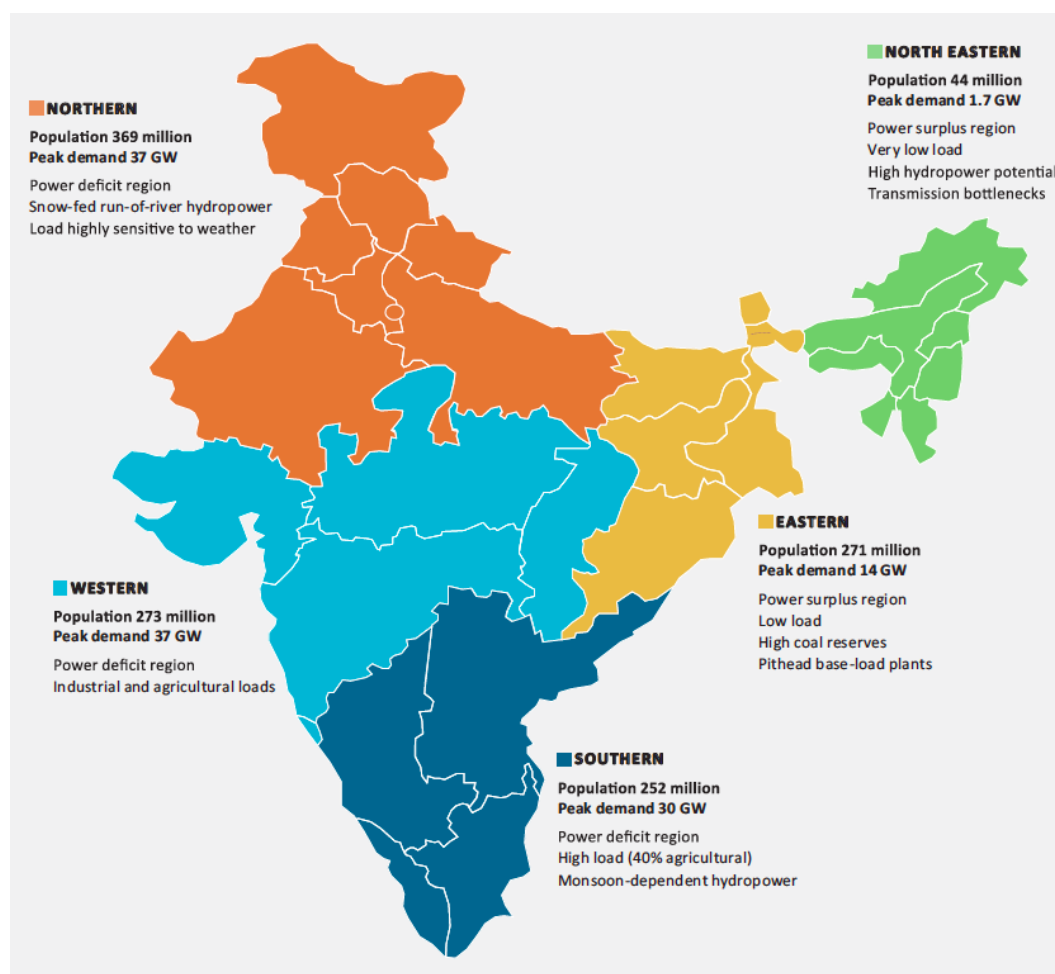


Figure 32: The five power grid regions of India (IEA, 2014a).

Key issues facing India's electricity system

One of the major issues with India's power system is the extremely high rate of transmission and distribution (T&D) losses. The World Bank (2014) estimate that 21% of electricity generated is lost, but other studies have estimated losses as high as 30% (Bairiganjan et al., 2010). The high amount of T&D losses is a result of insufficient investment into the distribution networks, commercial losses, illegal tapping of lines by end users and faulty electrical meters (Gambhir et al., 2012).

Even with only a 75% electrification rate, the quality of the electricity service delivered to consumers is inconsistent and India has been in power deficit for many years (IEA, 2014c). In 2013, India generated 1218 TWh of power but the demand was 1764 TWh leaving a 31% shortfall in average demand. The reasons for this high shortfall were stated as being due to a shortage of both coal and gas as well as unscheduled outages, extended periods of maintenance and poor inflows from hydro stations due to a weak monsoon (CEA, 2013). To cope with the power deficit, distribution companies often undertake load shedding whereby power is completely cut from one section of the system. This results in frequent rolling black outs in some areas and on average, 15-18% of peak demand is currently not met (Gambhir

et al., 2012). It is estimated that this peaking power shortfall could increase to 25% by 2017 (McKinsey, 2014). In July 2012, the largest electrical blackout in history affected 670 million people across India due to the collapse of three northern grids (IEA, 2012).

The unreliability of the power system has led to a number of industries and businesses setting up their own 'captive power plants' so that they have direct control on their supply of power (IEA, 2014c). These captive power plants are often found in very energy intensive industries such as cement, sugar and fertilisers due to the opportunities for co-generation (i.e. production of steam and heat as well as electricity). The issue with these plants is that they are commonly fuelled by coal or diesel and are therefore very carbon intensive.

The carbon intensity of electricity generation in India is the highest in the world at 964 gCO₂/kWh due to the dominance of fossil fuel capacity and inefficiencies in electricity infrastructure. For comparison, the carbon intensity of electricity production in China is 727 gCO₂/kWh with the UK emitting 398 gCO₂/kWh and the average for Europe being 294 gCO₂/kWh (Enerdata, 2014a).

6.2.2 Resource Potential

Fossil fuels and uranium

India is estimated to have the 5th largest reserves of coal globally, but there are differing opinions of the actual quantity of proven coal reserves. BP (2015) estimate the proven reserves to be 60 billion tonnes whilst the government's Ministry of Coal estimate 120-300 billion tonnes (Ministry of Coal, 2013). Most proven reserves in India are of low quality with a high ash content of between 30-50% and an average heating value of around 4500 kcal/kg (IEA, 2014a). As a comparison, the heating value of coal in the USA is between 6000-7500 kcal/kg (MIT, 2007). The Indian government recently mandated the washing of poor quality coal at the mine mouth to reduce the ash content and Coal India has announced plans to build 20 new washing facilities (WEC, 2012).



Figure 33: Map of major coalfields and coal infrastructure in India (IEA, 2011).

The reserves are concentrated in the north-eastern states (see Figure 33) whilst the centres of highest demand are located in the western and southern states (Gambhir et al., 2014). Due to the high rates of T&D losses within the electricity grid, coal tends to be transported physically along railways to areas of high demand. However, the lack of infrastructure and poor heating quality of Indian coal means that the cost of transportation on an energy basis is 15-30% higher than for example, in the USA (IEA, 2014c). The transport distances associated with domestic coal are substantial with a large accompanying carbon footprint along the journey. The Ministry of Coal is currently overseeing railway expansions of over 450 km to connect more remote reserves and to cater for the planned growth in production (Ministry of Coal, 2015).

Two state owned companies, the Oil and Natural Gas Corporation (ONGC) and Oil India Ltd control the majority of production and refining capacity within India (EIA, 2014). The

government has focused efforts on reducing the amount spent on fuel subsidies in recent years through domestic price reforms and integration of the private sector into both production and refining (EIA, 2014b). It is estimated that India had 5.7 billion barrels of oil reserves at the end of 2014 which is the second largest reserve capacity in the Asia-Pacific region after China (BP, 2015). 44% of oil reserves are onshore resources and 56% are located off-shore (EIA, 2014b).

India has modest natural gas reserves at 1.4 trillion cubic metres (tcm), which are located mainly off-shore in the Bay of Bengal (EIA, 2014b; BP, 2014). Gas was first discovered in the 1970s but output has steadily declined in recent years with deeper and more challenging reserves requiring expensive technology and infrastructure for exploration (WEC, 2012). The government have had policies to develop coalbed methane (CBM) as an alternative source of natural gas since 1997 when 30 CBM blocks were allocated for exploration and production to both private and state owned companies (WEC, 2012). However, movement on this potential resource has been slow with only three blocks producing CBM as of 2014. The potential reserves of CBM are estimated to be 4.6 tcm (IEA, 2014c). The MPNG is also looking into developing India's shale gas reserves but little work has been undertaken to date towards the characterisation of reserve estimates (EIA, 2014b).

India has around 185,000 tonnes of low grade uranium reserves which are mostly located in remote areas of the eastern states (DAE, 2012). India has abundant thorium reserves, around a third of the global total (WEC, 2012). The Department of Atomic Energy estimate that India has around 856,000 tonnes of thorium oxide (DAE, 2012).

Renewable Potential

India has a well-established hydropower sector and potential for further hydro development is estimated to be very large at 145 GW and mostly concentrated in the north eastern region. However, there are considerable issues related to environmental impact of large hydro schemes and the high up-front capital cost required which has prevented some large projects from progressing forward (IEA, 2014c). Along with the social and environmental impacts of inundating large areas of land, there are also issues due to the high sediment load of many rivers in India as they originate in the Himalayas. A high sediment load can damage hydroelectric plants through the erosion of the turbine blades and cause additional maintenance costs to the project (IEA, 2014a). As well as the potential for large hydro schemes, the government estimated the potential for small hydro schemes to be nearly 20 GW (CSO, 2015).

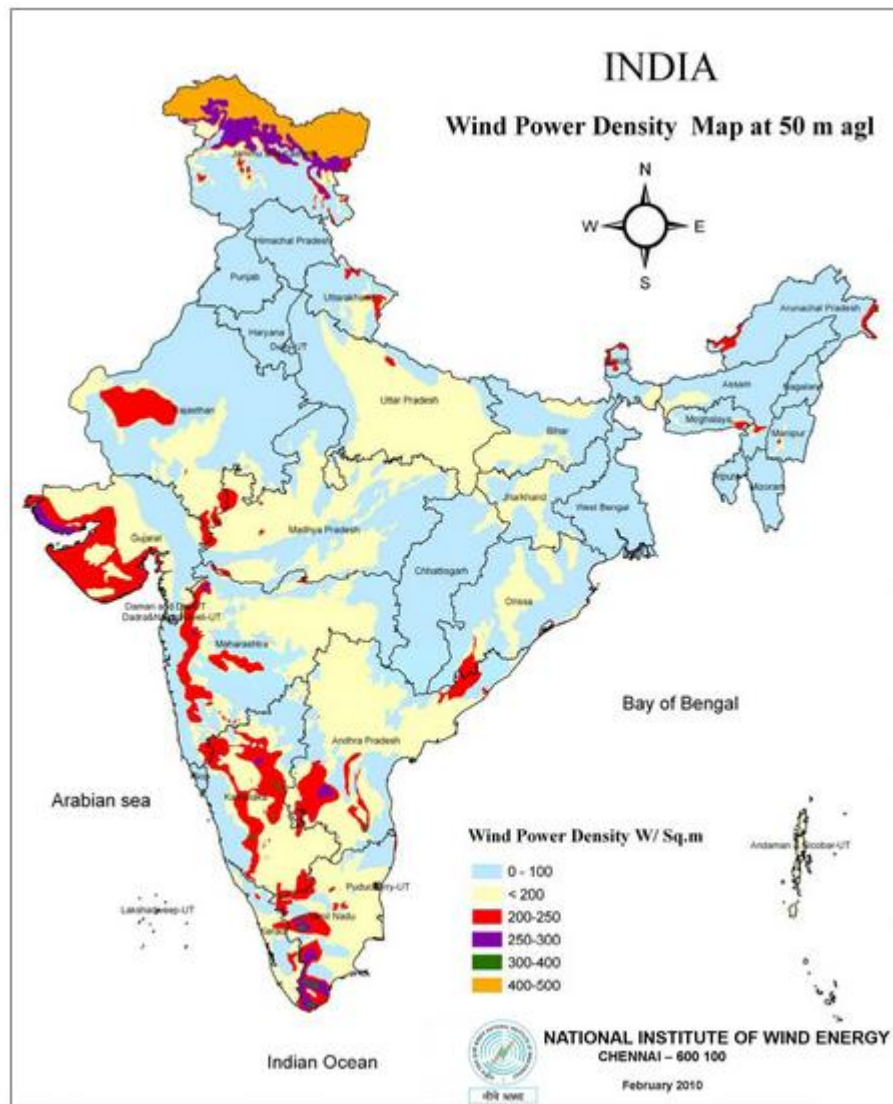


Figure 34: Map of wind power density at 50m above ground level (agl) across India (W/m^2) (NIWE, 2010).

Wind power potential in India is concentrated in the western and southern states as seen in Figure 34. Estimates of the full potential for wind power vary considerably from 48 GW (WEC, 2012) to around 500GW (SDSN and IDDRI, 2014). The Indian government estimate 103 GW of available wind potential (PC, 2013). The availability of wind energy in India is highly seasonal, with strong wind speeds only experienced in three to four months of the year, during the monsoon season. The wind potential is also unevenly distributed across the country with western states having a considerably higher potential than others (PC, 2013). There is also considerable off-shore potential but less work has been undertaken for the economic viability of certain sites. A feasibility study for the first demonstration 100 MW off-shore project along the coast of Gujarat was started in October 2014 as a joint effort between the MNRE, the IREDA and the National Institute of Wind Energy (MNRE, 2014b).

The Indian government estimate that there is around 18 GW of biomass potential and a further 5 GW of potential for bagasse cogeneration in sugar mills. Waste to energy applications were

estimated to have a potential for 2550 MW (CSO, 2015). Off-grid biomass gasification units have a high potential to be implemented in rural areas utilising agricultural residues or used in captive power generation for industries such as rice mills (TERI, 2015).

Solar insolation potential is high across the whole country, especially in the north-west and south-east of India (Gambhir et al., 2012). It is estimated that 58% of land in India receives isolation of over 5 kWh/m² per day (IDDRI & SDSN, 2014). This compares to the highest global values of around 6.5-7 kWh/m² in parts of North Africa, the Middle East and Australia, and lower values of 2.5-3 kWh/m² in Northern Europe. Many areas with high solar potential are however, not well connected in terms of major electricity grid lines meaning that lower potential areas may prove to be more cost effective for successful grid connections (WEC, 2012).

6.2.3 Energy Trade

India has large coal reserves, however insufficient domestic production rates and the disparity between the location of coalfields and the centres of high demand, have lead to coal shortages across the country (EIA, 2014b). To cope with the widening gap between domestic supply and demand, India has been importing thermal coal mainly from Indonesia and South Africa. The imports of coking coal for the steel industry from Australia have also been increasing (EIA, 2014b). Imports of coal have tripled over the past few years from 50 million tonnes in 2008 to 145 million tonnes in 2013 (Ministry of Coal, 2013). India is now the third largest importer of hard coal in the world (IEA, 2014c).

The 12th five-year plan outlined ambitious targets for the coal industry with a focus on enhancing domestic production through private sector investment and developing unconventional extraction techniques such as in-situ coal gasification (PC, 2006). Coal production is targeted to increase to 795 million tonnes by 2017 (an increase of 255 million tonnes from 2011) (PC, 2013). However, even with this huge increase in production, India will still need to import 185 million tonnes of coal in 2017 (WEC, 2012).

Despite having the second largest oil reserves in the Asia-Pacific region, India has become increasingly dependent on crude oil imports due to insufficient production of domestic oil and rapidly increasing demand. In 2009, 81% of crude oil was imported and this percentage is increasing each year. India imports crude oil mainly from the Middle East (Saudi Arabia supplies 20% of total crude oil imports), Venezuela and West Africa (EIA, 2014b).

India has been relying more and more on imported liquefied natural gas (LNG) from Qatar since 2004, when domestic natural gas reserves started to decline significantly in output (EIA, 2014b). Total LNG imports for 2013 reached 17.8 billion cubic metres (bcm) and India was the 4th largest LNG importer globally (BP, 2015). There are currently four regasification terminals for LNG and the capacity is set to increase by almost 50% by 2017 (WEC, 2012). India has a limited natural gas pipeline network and no international pipeline connections, which is the reason behind all imports being in the form of LNG (IEA, 2014c). There is a significant regional

imbalance in terms of access to natural gas and the MPNG has announced plans for a national gas grid to promote the use of natural gas for power generation. The network is expected to expand from its current 14,900 km to 28,000 km (IEA, 2012).

India is currently importing hydropower from Bhutan on a seasonal basis and also has connections to Bangladesh, Pakistan and Nepal. The member states of the South Asian Association for Regional Cooperation (SAARC) signed a framework agreement for energy cooperation and electricity trading in 2014 (SAARC, 2014). SAARC consists of Afghanistan, Bangladesh, Bhutan, India, the Maldives, Nepal, Pakistan and Sri Lanka. The framework is aimed at the optimal utilisation of regional energy resources through developing an integrated South Asian electricity grid (Matin, 2015). There is significant potential to increase the imports of power from Bhutan to India, taking advantage of the very large hydropower potential in the country.

6.3 Energy Policy and Drivers

6.3.1 Political System and Energy Administration Structure

The 29 states of India have individual elected administrations for local governance whereas the union territories are administrative divisions, controlled directly by central government through an administrator. The central government provides the socio-economic and political framework that the states must abide by, but the states have the ability to make independent decisions about how policies and legislation are implemented (IEA, 2012).

The central government has control over areas such as defence, airways and railways whilst individual states are responsible for sectors such as agriculture, water and public health. Examples of sectors where both the central government and states have shared responsibility are electricity, education, economic and social planning. This shared accountability can lead to conflicts within the complex planning processes and bureaucratic issues when implementing policies in these areas (MLJ, 2011). Energy (in particular electricity) is one sector where the states have considerable authority to control legislation within their territory. The individual states have their own energy departments to manage local issues and implement national policies, which accounts for differing degrees of power sector reform between states (IEA, 2012).

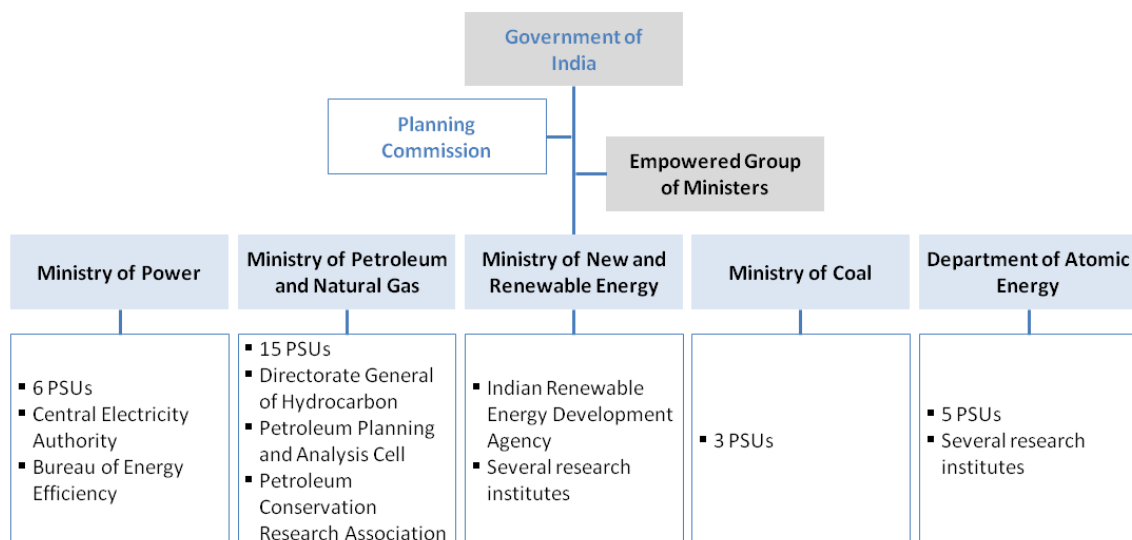


Figure 35: The institutional structure of energy administration in India. The Planning Commission has now been replaced by NITI Aayog (IEA, 2012).

Figure 35 outlines the five ministries that deal with energy policy within the Indian government. These include the ministries focused on fossil fuels i.e. the Ministry of Coal and the Ministry of Petroleum and Natural Gas and also those concerned with low carbon energy i.e. the Ministry of Atomic Energy and the Ministry of New and Renewable Energy. Each ministry has a number of associated Public Sector Undertakings (PSUs), which are state-owned companies such as Coal India Ltd. and the National Thermal Power Corporation (NTPC) (WEC, 2012). Coal India is now the largest coal producing company in the world and produces 81% of total production in India (Ministry of Coal, 2015). Under the Ministry of Power, the Central Electricity Authority (CEA) has a prominent role in formulating power sector policies and also sets out standards required of the system (IEA, 2012).

The Planning Commission used to be the body responsible for writing the five-year plans, which set the GDP growth rate target and identified priority issues for that period (PC, 2014). In January 2015, the Planning Commission was replaced by the National Institution for Transforming India (NITI) Aayog. The NITI Aayog was conceptualised in order to facilitate better inter-ministry coordination and aims to act as more of a think-tank advisory body (PM India, 2015).

6.3.2 Overarching Energy Policies

Energy policy in India is focused around increasing energy provision to the 25% of the population that lack access to electricity and enhancing energy security through decreasing import dependence (IEA, 2012). There is an on-going rural electrification scheme to expand access to remote parts of the country. Policies directed at climate change mitigation are becoming increasingly important but the Indian government has been very candid in outlining that energy security and access are first priorities (MEFCC, 2008). There are three key policies that define the overall framework of energy and electricity strategy in India:

The Integrated Energy Policy (2006)

The Planning Commission (PC) was instructed “to prepare an integrated energy policy linked with sustainable development that covers all sources of energy and addresses all aspects of energy use and supply” (PC, 2006). The aim of creating this Integrated Energy Policy (IEP) was in order to bring together the somewhat segregated ministries responsible for individual energy sources. The IEP focused on the importance of aligning energy specific goals with the overarching policy framework of sustaining economic growth in India and ensuring a transition to a market based economy (IEA, 2012). An emphasis was placed on power sector reforms to address the technical and commercial losses of the transmission and distribution systems (PC, 2006).

Policy measures to enhancing energy security are rapidly growing in importance due to India’s import dependence having increased from 11% in 1990 to 35% in 2009 (EIA, 2014b). This is mainly due to the rapid increase in crude oil import. McKinsey (2014) estimated in their business as usual scenario that import dependence would rise to 51% by 2030. The IEP aims to encourage private investment into the sector for accelerated exploration and utilisation of natural resources, in particular the abundant thorium reserves that India holds. The IEP does place some importance on expanding renewable forms of energy for enhanced energy security, particularly solar PV technology. However, in order to “reliably meet the demand for energy services of all sectors at competitive prices” the importance of coal as the dominant primary fuel for the long-term energy strategy was reinforced (PC, 2006).

A key challenge of the policy is to increase the electricity provision to the rural areas that currently have no access to energy whilst fulfilling other contrasting objectives such as reducing the cost of power. An estimated 815 million people (66% of India’s total population) rely solely on traditional biomass for cooking (TERI, 2015). The Environmental Performance Index (EPI) ranked India 174 out of 178 countries for its air quality, with particular note to indoor air pollution from using inefficient cookstoves (EPI, 2014). To tackle this growing health issue, the IEP calls for the provision of clean cooking energy for all households within 10 years alongside the on-going rural electrification schemes.

The 12th five-year plan (2012-2017): ‘Faster, sustainable and More Inclusive Growth’

The five-year plans have a primary focus on economic growth but have direct impacts on the energy sector through setting energy demand projections and outlining investments into power infrastructure (PC, 2013). Setting a high GDP growth rate has always been an important part of the plans but the 12th Plan emphasises a more ‘inclusive’ growth process by which the benefits can be transferred to the wider population (IEA, 2012). The GDP growth rate for 2013 was 6.9% and the aim is to increase this to 9% by the end of the 12th plan. The plan has set 25 targets that will be monitored throughout this five-year period. Table 11 details important targets relevant to the energy sector.

Table 11: Targets relevant to the energy sector outlined in the 12th Plan

Chapter of the Twelfth Plan	Core indicators related to the energy sector
Economic growth	Real GDP growth rate of 8% (average 2012-17)
	Manufacturing growth rate of 10%
Infrastructure	Provide electricity to all villages
	Reduce AT&C losses to 20% by the end of the Twelfth Plan
Environment and sustainability	Add 30,000 MW of renewable energy capacity
	Reduce emission intensity of GDP by 20-25% of 2005 levels by 2020

The National Electricity Plan

The Electricity Act was released in 2003 to introduce competition into the electricity market. As previously discussed, the state electricity boards were unbundled into separate generation, transmission and distribution companies, regulated by State Electricity Regulatory Commissions (SERCs). A requirement of the Electricity Act was that the CEA must prepare a National Electricity Plan every five years. The objectives of the plan are to forecast electricity demand for both the short-term five year period but also a longer-term 15 year outlook (CEA, 2012a). The National Electricity Plan was released in 2012 and forecasts the potential capacity additions under several scenarios based on demand projections, fuel availability and economic growth.

6.3.3 Other Important Energy Policies

The Three Stage Nuclear Strategy

The government of India has had a long-term three-stage nuclear power strategy to utilise the countries domestic uranium and thorium reserves. The Department for Atomic Energy (DAE) has developed India's domestic uranium exploration and nuclear power generation over the past 60 years (IEA, 2014c). The Nuclear Power Corporation of India Ltd (NPCIL) is a public sector undertaking of the DAE, responsible for nuclear power plants.

The first stage of the strategy, which was the development of uranium fuelled Pressurised Heavy Water Reactors (PHWRs), is complete but with several projects still under construction. The second stage of the nuclear strategy is to develop Fast Breeder Reactors and associated fuel cycle technologies, which will utilise plutonium based fuel. Another public sector undertaking, BHAVINI, is responsible for the fast breeder reactors (FBRs) and is in the process of setting up a 500 MW prototype FBR at Kalpakkam (WEC, 2012). The third stage aims to develop India's long-term goal of utilising the abundant domestic thorium reserves with Advanced Heavy Water Reactors (AHWRs). These reactors will be based on the thorium-uranium-233 cycle where the irradiation of thorium in PHWRs and FBRs produces uranium-233 (WEC, 2012). The Department of Atomic Energy has a number of research AHWRs and aims to have a full prototype AHWR by the early 2020s (DAE, 2014).

India's Approach to Climate Change

India's approach to climate change was briefly outlined in the IEP, highlighting their very low value of per capita emissions compared to other developed countries and their belief that the "significant responsibility (for dealing with climate change) does not lie with India" (PC, 2006). The IEP communicates that India's continuing economic growth should not be disrupted by constraints on the current levels of CO₂ emissions unless compensated for the additional costs incurred.

The National Action Plan on Climate Change (NAPCC) was released in 2008 and is a comprehensive document detailing India's approach to climate change. It indicates that India will not accept similar emission reductions as developed countries due to the importance of maintaining a high economic growth rate in order to pursue their development goals (MEFCC, 2008). The NAPCC outlines eight core missions that will run to 2017, two of which are directly energy related: the Jawaharlal Nehru National Solar Mission (JNNSM) and the National Mission for Enhanced Energy Efficiency (NMEEE). The responsibility for the implementation, monitoring and evaluation of the missions lies with individual energy ministries or agencies, i.e. the Ministry of New and Renewable Energy and the Bureau of Energy Efficiency. The NAPCC states that India's per capita emissions will "at no point exceed that of developed countries" which is unlikely to occur since India's CO₂ emissions of 1.7 tCO₂ per capita are only around 40% of the world average of 4.3tCO₂ per capita (Enerdata, 2014a).

Emission regulations and Carbon Tax

The Indian government has set restrictions on particulate emissions from coal power stations but only one company (the NTPC) actually has monitoring in place to assess particulate emissions. There are currently no direct emission regulations for NO_x or SO₂ from coal fired power stations (Cropper et al., 2012). There is a coal tax in place in India and the finance minister recently doubled the level of this tax to Rs200 (US\$ 3.25) per metric ton of coal mined (Bhaskar, 2015). The revenue generated goes towards the National Clean Energy Fund that aims to provide funding to clean energy initiatives (PC, 2013).

Renewable Energy Policies

The Ministry of New and Renewable Energy (MNRE) is responsible for administering renewable energy strategy for India. The Electricity Act (2003) and National Tariff Policy (2006) have both been important sources of legislation surrounding renewable energy. The Tariff Policy initiated the Renewable Purchase Obligations (RPOs), which mandate that distribution companies must purchase a certain percentage of grid-based power from renewable sources (IEA, 2012). The misalignment between the potential for renewable energy in a certain state and targets set out via the RPOs led to the creation of a Renewable Energy Certificate (REC) mechanism to rebalance and stimulate the market (PC, 2013). Trading of REC's across India began in 2011 but has had a slow start.

The MNRE launched a Generation Based Incentive (GBI) for wind and solar power in 2008 to help fulfil their capacity targets. Wind projects larger than 5 MW are eligible for a GBI. Solar projects are limited to 5MW per developer up to a maximum of 10 MW per state. The GBI's are funded by the MNRE but administered by the Indian Renewable Energy Development Agency (IREDA), a public company. At the state level, there are a number of other incentives for renewable energy deployment such as Feed-in-Tariffs established by the state governments (Enerdata, 2015f).

Under the 12th Plan, the National Bioenergy Mission was initiated. The policy outlined India's strategy for accelerating the production and use of biofuels within the transport sector and developing bioenergy applications for the power sector. A 20% blending target for transport fuels by 2017 was announced for both ethanol and biodiesel which is a rapid increase from the current 5% mandatory blending requirement (MNRE, 2009). All the policies discussed above are summarised in Table 12.

Table 12: Summary of key energy policies in India

Date	Policy	Details
2001	<i>Energy Conservation Act</i>	Large energy intensive industries must undertake energy audits.
2003	<i>Electricity Act</i>	Unbundled the State Electricity Boards. Mandates the State Electricity Regulatory Commissions (SERCs) to develop RE in their states.
2005	<i>National Electricity Policy</i>	Peaking shortages to be addressed along with on-going rural electrification schemes.
2006	<i>Integrated Energy Policy</i>	Coal to remain dominant fuel source. Energy security and access are key issues addressed.
	<i>National Tariff Policy</i>	Initiated the Renewable Purchase Obligations. Mandated states to introduce time of day metering to reduce peak loads.
2007	<i>11th Five Year Plan</i>	Introduced goal to increase energy efficiency by 20%.
	<i>Energy Conservation Building Code</i>	Mandatory appliance labelling scheme.
2008	<i>National Action Plan on Climate Change</i>	India's approach to climate change with eight core missions.
2012	<i>National Electricity Plan</i>	Forecasts of potential capacity additions under several scenarios based on demand projections, fuel availability and economic growth.
2013	<i>12th Five Year Plan</i>	Faster, sustainable and more inclusive growth.

6.4 Current Generation Capacity

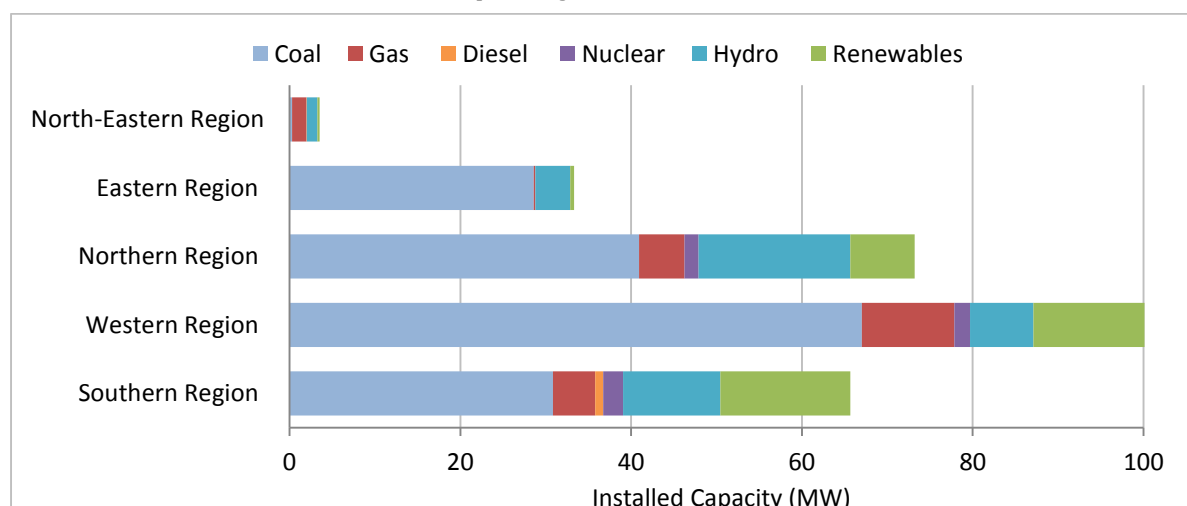


Figure 36: Installed capacity by fuel in each region of India (MW) (CEA, 2015a).

The generation capacity varies significantly from state to state according to the types of fuel resources available and the individual state government's energy policies. For example, the southern state of Tamil Nadu has a large share of renewable capacity (42% in 2012) due to strong promotional policies initiated by the state government whereas West Bengal has predominantly coal based generation due to its large domestic reserves (IEA, 2012). The western region has the highest installed capacity as seen in Figure 36. The western states of Maharashtra and Gujarat together represent 24% of the total installed capacity of India (IEA, 2012).

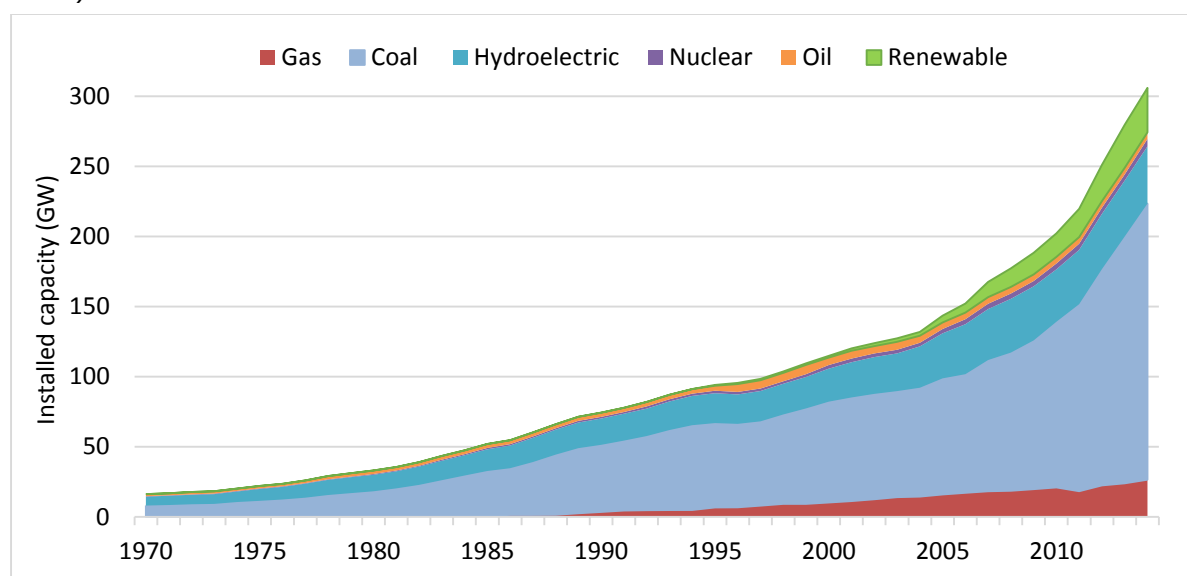


Figure 37: Historical changes in the installed capacity for India from 1970-2014 (Enerdata, 2014a).

Total installed capacity in India has increased dramatically from 16 GW in 1970 to 306 GW in 2014 as seen in Figure 37. Coal is the dominant energy source accounting for 64% of the installed electricity generating capacity (IEA, 2014c). Consumption of coal has steadily been

increasing since the 1990s following the economic boom that India has experienced. Since 2007, over 100 GW of coal-fired capacity has been added taking the total to 197 GW (Enerdata, 2014a). The IEA estimated the average efficiency of Indian coal power stations to be 33.1% with specific CO₂ emissions of 1.1 gCO₂/kWh. This emissions level is well above that of ultra-supercritical units, which have specific emissions of 0.75 kgCO₂/kWh and efficiencies reaching 48-50% (WCA, 2015). Over 90% of Indian coal power stations use subcritical technology (IEA, 2014c).

Natural gas started to enter the generating capacity in the early 1990's and currently makes up 9% of total capacity with 26 GW installed. However, it can be observed in Figure 38 that electricity production from natural gas was only 5% in 2014. This is as a result of increasing supply issues associated with natural gas and indicates the preference of cheaper coal to be used in generation.

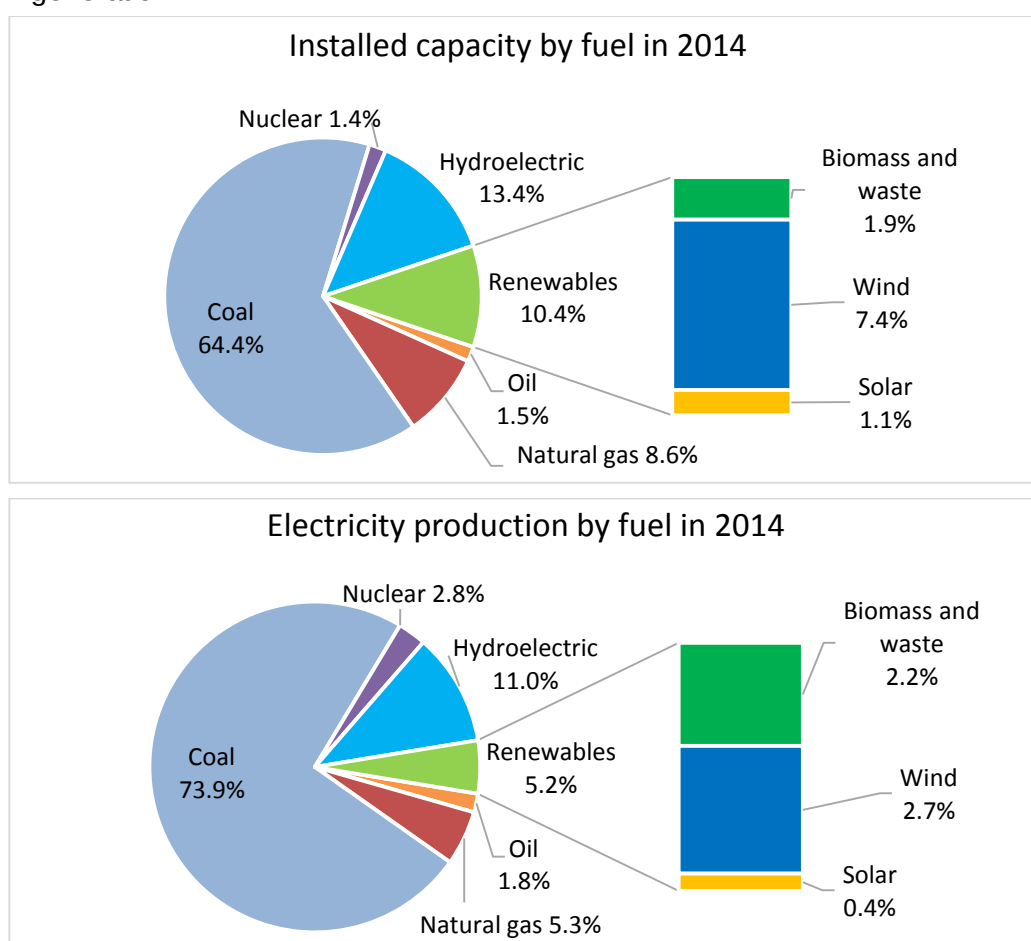


Figure 38: Comparison of installed electricity and electricity generation by fuel in India in 2014 (Enerdata, 2014a).

Hydroelectric power has had an important role in electricity generation over the past 40 years and now represents 13.4% of the installed generating capacity (41 GW) as seen in Figure 38. Hydropower capacity is highest in the northern states such as Himachal Pradesh, situated within the Himalayan valleys. Generation from hydropower depends heavily on the monsoon patterns from year to year. Despite having a long history of nuclear power development since

the 1950s with the three stage nuclear strategy, nuclear power represents only 1.7% of generating capacity (5.3 GW) as seen in Figure 38. India currently has 21 operational nuclear reactors (EIA, 2014b).

Renewable capacity in India has grown significantly over the past 10 years from 1.2 GW in 2000 to 31.7 GW in 2014 (Enerdata, 2014a). Figure 38 shows that renewable capacity makes up 10.4% of total installed power capacity and highlights the dominance of wind energy in the renewable energy mix. However, it can be observed that renewable energy contributed only 5.2% to the overall electricity generation, skewed by the increased proportion of coal in electricity production. Figure 39 indicates the amount of electricity produced from renewable sources, highlighting the rapid increase over the past 10 years. Total generation from renewables reached 66 TWh out of the overall electricity generation of 1296 TWh in 2014. Solar power in India has grown significantly in the last five years with the launch of the Jawaharlal Nehru National Solar Mission (JNNSM) in 2010. The total installed capacity has increased rapidly from 6 MW in 2009 to 3380 MW in 2014, now representing 11% of the total renewable capacity (Enerdata, 2015f).

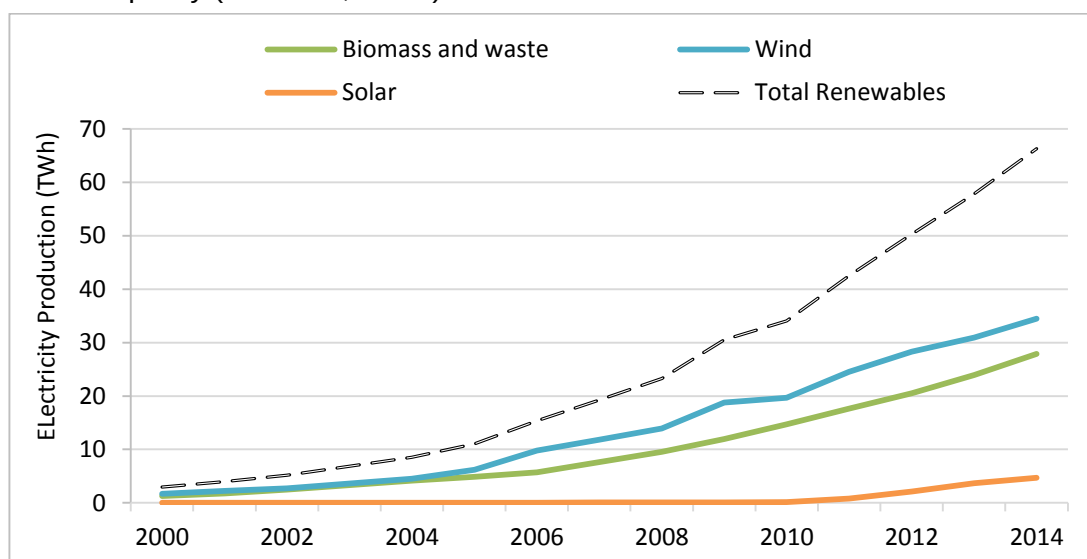


Figure 39: Renewable electricity production from individual sources from 2000-2014. Total electricity production from renewable sources is shown as reference (Enerdata, 2014a).

The increase in renewable deployment over the past 10 years has mainly been driven by private investment in the southern and western states exploiting the abundant wind power potential available. Installed wind capacity accounts for more than two-thirds of the total renewable capacity with 23 GW installed as of 2014 and India is ranked 5th globally in terms of onshore wind deployment (WEC, 2012). The states with the highest installed renewable capacity are shown in Figure 40. The top five states in terms of renewable capacity (all located in the western or southern regions) account for nearly 80% of the total installed renewable capacity of India.

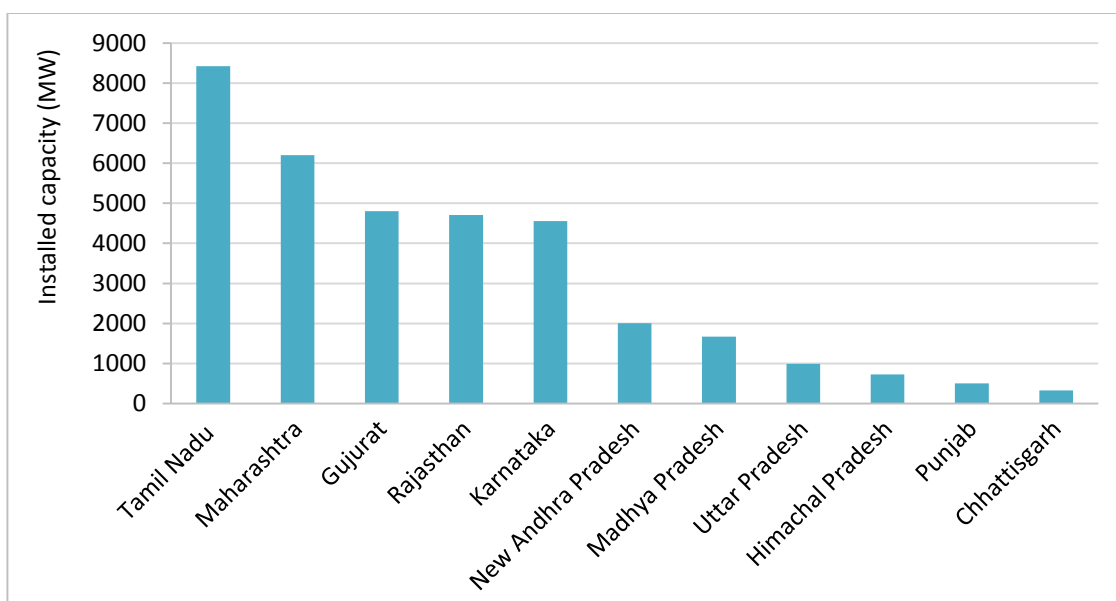


Figure 40: The ten states with the highest installed renewable capacity in India (CEA, 2015a).

Discrepancies in the data

It is interesting to note that there have been a few disparities found in the installed capacity estimates for India. Graphs of installed capacity and generation have been taken from Enerdata to keep consistency throughout the report but where possible, updated values from the Central Electricity Authority have been checked against these. It can be observed from Table 13 that the most drastic differences are in the coal and diesel capacity values. In the Enerdata statistics, the diesel capacity has remained at the same value of 4.7MW since 2006 which contrasts to the CEA statistics. The differences in the coal capacity are quite large and could be due to a difference in estimation of the autoproducer and captive power plant share of the total coal capacity. Enerdata use the CEA's statistics in their database but make an estimate of the autoproducer share, which could account for the differences in coal capacity values.

Table 13: Comparison table of installed capacity values from (CEA, 2015a) and (Enerdata, 2014a).

Fuel	Installed capacity (GW)	
	(CEA, 2014)	(Enerdata, 2014)
Coal	153.6	197.0
Natural Gas	23.0	26.5
Diesel	1.2	4.7
Nuclear	4.8	5.3
Large Hydro	40.8	40.9
Renewables	31.7	31.7
Total	255.1	306.1

6.5 Discussion and Analysis

6.5.1 Government Projected Capacity

Historically, India has a tendency to underachieve its thermal capacity targets. From 1995-2012, only 65% of the capacity targets were actually implemented (IEA, 2014c). There are a range of capacity targets and projections stated by different ministries and agencies within the Indian Government. The lack of clarity makes it difficult to assess what the general direction of transition that the electricity system is likely to undergo. Due to these disparities, the capacity projects stated by the various government agencies for each fuel sector will be first discussed. Subsequently, the overall capacity targets will be outlined, highlighting differences between them.

Coal

The Ministry of Power launched the Ultra Mega Power Projects (UMPP) in 2005 to provide the much needed capacity additions to the electricity system and develop supercritical technology in India (PFCL, 2015). Each of the 16 planned UMPPs will have a large capacity of around 4000 MW and feature supercritical boiler systems (Pandey et al., 2013). A competitive bidding process for the projects was implemented and four projects have been approved by the CERC. Two UMPPs have been fully commissioned. Tata Power commissioned the first UMPP plant at Mundra, Gujarat that has a total capacity of 4620 MW from nine units and is designed to operate on imported coal from Indonesia. Reliance Power started operations at the 3960 MW Sasan UMPP in April 2015 (Enerdata, 2015f).

Box 1: Status of Carbon Capture and Storage (CCS) in India

India has expressed an interest in getting involved with international demonstration CCS projects. In the Planning Commission's energy scenario calculator, CCS is highlighted as being an important but very uncertain technology for deployment in India. In their moderate effort scenario, CCS develops at a slow pace and by 2047, an estimated 35 GW of power generating capacity features CCS technology. However, there are several issues associated with the potential development of CCS in India. Given the already low standard of power station efficiencies, having an additional efficiency penalty through the retrofitting of a CCS unit would be very detrimental (Gambhir et al., 2014). The new supercritical coal power plants that are beginning to enter the generation mix would be in a better position to adopt CCS technology given their higher efficiencies. Another key issue is the lack of geological knowledge when it comes to potential storage sites for captured CO₂. Fully characterising the suitable geological units for storage would be a long and costly process (IEA, 2014c).

The 12th Plan states that 50% of the coal based capacity additions would be supercritical units, which would have specific CO₂ emissions of around 0.83 kgCO₂/kWh (PC, 2013). However, based on announcements of new coal plants, it is estimated that only 23% of capacity additions up to 2020 will feature supercritical technology, the majority being subcritical units.

Enerdata (2015f) stated that there are 14.2 GW of coal plants under construction and a further 48 GW of coal capacity in the planning or approved stages over the next 10-15 years.

Natural gas

India began importing LNG in 2004 when domestic production started to decline significantly. Severe natural gas supply constraints and rising LNG prices on the global market have meant that there is not enough natural gas for the existing plants, resulting in declining plant load factors over the past few years (IEA, 2014c). Nevertheless, it is estimated that around 11.3 GW of natural gas capacity is in the planning or approved stages. Karnataka Power Corporation are planning a 2100 MW CCGT plant in Tamil Nadu based upon the proximity to an LNG terminal (Enerdata, 2015f).

Nuclear

In the long term, the Indian government is aiming for nuclear energy to make up 25% of power generation by 2050 (Gambhir et al., 2012). There is an expansion underway of the Kudankulam Nuclear Power Plant in Tamil Nadu which consists of a 1000 MW pressurised water reactor (PWR) unit. A second 1000 MW unit is under construction and planned to start operating in November 2015 (NPCIL, 2015). Four Pressurised Heavy Water Reactors (PHWRs) are also under construction, each with a generating capacity of 700 MW that aim to be operational by 2016/2017 (Power Technology, 2015).

In 2009, the NPCIL and the French company AREVA signed a Memorandum of Understanding (MoU) for the development of the Jaitapur nuclear power project, which would consist of six European Pressurised Reactor (EPR) reactors. The Jaitapur plant would be the largest nuclear power station in the world with a total capacity of 9900 MW when completed. There is much controversy over this project with growing public apprehension over the safety of nuclear power after the Fukushima disaster. The locals are also concerned about the environmental impacts of the power station's effluent on marine life in this coastal region, as fishing is an important revenue source (Chopra, 2011). The first two units of the Jaitapur plant have been approved despite the on-going public opposition and are expected to start operation in 2021 (Enerdata, 2015f).

Hydro

The potential for hydropower to be used as a large-scale backup power source is gaining importance within India (EIA, 2014). In 2003, the '50,000 MW Hydroelectric Initiative' was launched which outlined the hydroelectric strategy for 162 new projects up to 2017 totalling 47.9 GW (CEA, 2015c). As of June 2015, 21.3 GW of projects were in various stages of construction or approval. However, 23.9 GW has been held up due to a variety of issues including a change in the state agency involved, local objections and problems with obtaining clearance from the Ministry of Environment and Forests (CEA, 2015c). A large proportion of

the planned hydro projects are within the state of Arunachal Pradesh including 9.7 GW of hydro dams proposed along the Siang River (Enerdata, 2015f).

Renewable Energy

The MNRE are in the process of developing a National Wind Mission, in addition to the National Solar Mission initiated under the NAPCC (Mishra, 2015). Wind capacity additions under the 12th Plan have exceeded targets so far despite a slowdown in the investment in wind power in 2012 (IEA, 2014c). Both off-grid and grid connected biomass energy systems are being promoted by the MNRE. Despite the high potential for both biomass and waste to energy applications, the capacity additions occurring are on a small scale. Certain states have set up preferential tariffs for biomass power projects and IREDA provides some fiscal incentives such as a ten year 'tax holiday' for certain schemes (IREDA, 2015). There are around 30 biomass power projects under construction amounting to 350 MW capacity. In addition, there are 70 co-generation schemes in the planning, totalling 800 MW (MNRE, 2014a). The MNRE is particularly promoting the use of biomass co-generation in industry with the provision to export surplus power to the grid and provide electricity for the local area.

The National Solar Mission initially set a target of increasing solar capacity by 20 GW but this was revised in 2014 to an ambitious 100 GW by 2022 (MNRE, 2015). The MNRE has proposed a scheme for the development of 10 ultra-mega solar power projects that will be implemented by the public sector enterprise, the Solar Energy Corporation of India (SECI) working with individual state governments. The large-scale solar parks will be above 500 MW in capacity (TERI, 2015). Gujarat is the first state to commission a solar park of 600 MW capacity (TERI, 2015). The state government in Rajasthan have set a target to implement 25 GW of solar energy by 2022 and in 2015, Adani Power has signed a MoU with the state government to build a 10 GW solar power park (Adani, 2015).

There is also a target for 2,000 MW for off grid solar power by 2022 to provide clean electricity to rural communities. There has been a capital subsidy of 30% for solar micro-grids (up to 100 kW scale), solar lanterns, street lights and water pumps but this has not proven to be sufficient to gain adequate investment from developers (TERI, 2015). The MNRE envisages grid parity for solar energy by 2022 (PC, 2013).

6.5.2 Overall Government Capacity Targets

Overall capacity targets are somewhat ambiguous for India's power sector. With multiple agencies involved in energy policy, different documents outlining targets, scenarios and aims can be found for the period leading up to 2022. This section outlines three of these different ambitions: the 12th Plan targets, the CEA scenarios and the MNRE renewable targets.

The 12th Five Year Plan stated that 118.5 GW of new capacity is to be added to India's power system between 2012 and 2017. The breakdown of this target can be observed in Table 14 against the capacity addition achievements as of 2015. It can be observed that there has been

significant progress with meeting the thermal target. However some of the other fuels are looking unlikely to meet the 2017 targets. This is particularly evident with the hydropower capacity additions, which are looking unlikely to meet the ambitious 10.9 GW target by 2017. The large target for hydro (particularly those with storage capacity) additions derives from the critical need for peaking power plants in India to provide quick response power during peak times (CEA, 2012a).

Table 14: Capacity additions targets (not cumulative totals) for the 12th plan and achievements up to January 2015 (CEA, 2015b)

Sector	Target for 12 th plan up to 2017 (GW)	Achievement up to January 2015 (GW)
Thermal	72.3	49.2
Hydro	10.9	1.9
Nuclear	5.3	1.0
Renewables	30.0	16.3
Total	118.5	68.4

The CEA released the National Electricity Plan in 2012 and developed three scenarios for installed capacity additions during the 12th and 13th Five Year Plan periods. The scenarios are based around the development of renewable energy and the availability of natural gas in the future and are outlined in Table 15. There is great uncertainty over the future availability of natural gas in India but given the estimation that 11.3 GW of natural gas capacity is in the planning, it seems that natural gas will continue to play a role in the power sector for at least the remainder of the 12th Plan. In addition, based on the recent announcements from the MNRE of the ambitious 175 GW renewable energy target by 2022, it can be assumed that a 'High Renewables, High Gas' scenario (Scenario 3) is most representative of the current policy vision although this could be a disputed matter.

Table 15: The various scenarios for capacity additions during the 12th and 13th Five Year Plans developed by the CEA. Base scenario is 'Low Renewables, Low Gas' and Scenario 3 is 'High Renewables, High Gas'. Retirement of plants is taken to be 4000MW across all scenarios for each 5-year period (CEA, 2012a).

	12 th Plan (2012-2017) Capacity Additions (GW)		13 th Plan (2017-2022) Capacity Additions (GW)	
	Base scenario	Scenario 3	Base scenario	Scenario 3
Thermal total	67.7	64.5	49.2	47
Coal	66.6	51.4	49.2	34
Natural gas	1.1	13.1	0	13
Nuclear	2.8	2.8	18	18
Hydro	9.2	9.2	12	12
Renewables total	18.5	30	30.5	45
Wind	11	15	11	20
Solar	4	10	16	20
Other RE	3.5	5	35	5
Total capacity additions	94.2	102.5	105.7	118

Figure 41 highlights what the electricity capacity mix would look like under the different targets from the 12th Plan, CEA and MNRE for 2017 and 2022. In all cases, the amount of coal capacity is targeted to increase, providing the majority of new capacity up to 2022. However the percentage share of coal decreases due to the growing importance of renewable capacity, particularly by 2022.

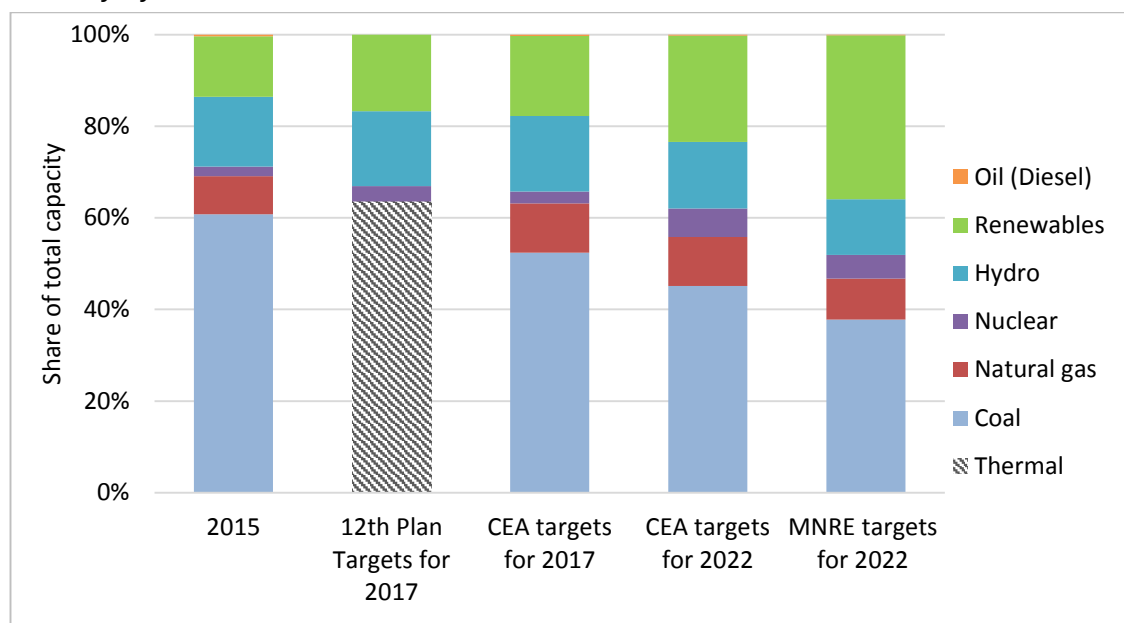


Figure 41: The fuel share of total capacity in 2015 and under different capacity targets outlined by the 12th Plan, CEA and the MNRE for 2017 and 2022.

The 12th Plan and CEA targets are fairly similar for 2017, although the 12th Plan only specified a thermal target and did not differentiate between natural gas and coal capacity additions. However, when the potential capacity mix is compared under the CEA targets and the MNRE targets for 2022, there are vast differences, particularly in the renewable capacity share.

With 16.3 GW of renewable capacity added to the system from 2012-2015 (see Table 14), a real acceleration in deployment is occurring. It seems likely that the 30 GW renewable target outlined in the 12th Plan could be met. However, there have been multiple contrasting targets released for renewable deployment. In addition to the 30GW target outlined in the 12th Plan, the CEA targeted an addition of 45 GW of renewable capacity by 2022 in the National Electricity Plan (2012), which would lead to a total renewable capacity of 65 GW. MNRE has recently announced clear ambitions for renewable capacity to reach a total of 175 GW by 2022 (MNRE, 2015). The vast difference in renewable targets can be seen in Figure 41 where renewable capacity accounts for 23% under CEA's targets compared to nearly 36% under MNRE targets. The discrepancies in capacity targets, particularly within the renewable sector (see Table 16) creates a lot of uncertainty when trying to understand India's goals and results in an ambiguous environment for investors.

Table 16: Different projections of cumulative renewable energy capacity by 2022 under CEA and MNRE targets.

	Projections of cumulative renewable capacity for 2022 (GW)	
	(CEA, 2012a)	(MNRE, 2015)
Mini hydro	4.6	5
Biomass and waste	8.9	10
Wind	51	60
Solar	30	100
Total	94.5	175

The lack of transmission capacity is a key barrier to increased renewable deployment. The location of many of the proposed wind and solar projects are in areas that are not well connected to the national grid, so gaining a connection can be a slow and costly process. Major infrastructure enhancements need to be undertaken in order to effectively integrate increased levels of renewable generation into the system as well as detailed planning of the electricity grid system in order to assess these issues.

There is considerable activity underway to target some of these issues but progress is slow and costly due to the considerable level of action needed. The Indian government has recently approved the National Smart Grid Mission under the Ministry of Power with a view to creating a national smart electricity grid to alleviate the many current issues with the network (MP, 2015). There will be 14 pilot smart grid projects across the country starting in 2015 and national implementation by 2027 (Pillai, 2014). Given the complex nature of this project, creation of a national smart grid by 2027 seems optimistic.

6.5.3 Enerdata Projections

Potential scenarios for India's predicted capacity mix up to 2040 are shown in Figure 42. Enerdata's scenarios are shown along with the potential capacity mix based on the targets set out by the MNRE and the CEA. It can be observed that the Balance and Renaissance scenarios predict a dominance of thermal generation continuing up to 2040. It can be noted that there is a large disparity between the Balance scenario (which is based on current policies) and the CEA targets which are based on the government's current capacity plans. The fact that Enerdata's scenarios are so vastly different from the government's predictions are an indication that Enerdata are not taking into account the most recent energy policies in India. It could also be a suggestion that the Enerdata model assumes that the targets set out by the government are too ambitious and will not be met. The large discrepancies between these scenarios highlights the uncertainty surrounding India's future capacity transition.

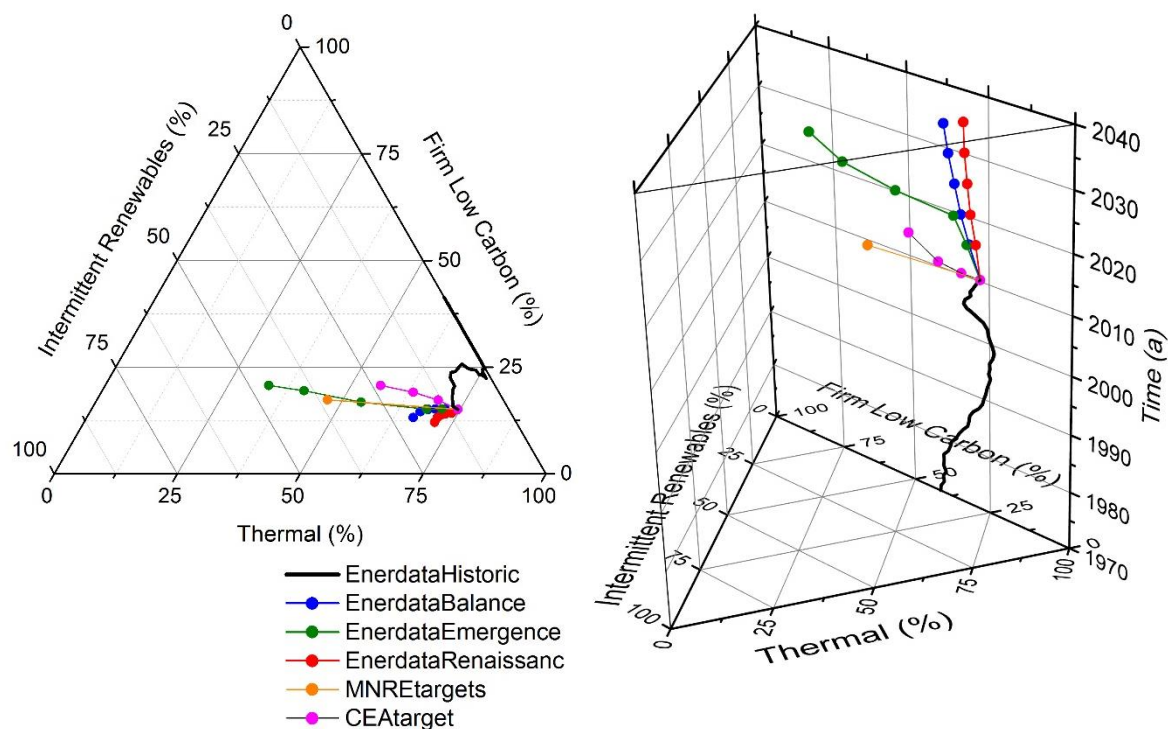


Figure 42: India's projected capacity scenarios based on government targets (CEA, 2012a; MNRE, 2015) and Enerdata scenarios (Enerdata, 2014a).

The Emergence scenario (which is based upon reaching the global 2°C target) along with the MNRE and CEA targets, predict a much larger share of renewable capacity. To reach the MNRE target, a huge shift in the current capacity trajectory is needed over a very short timescale which is depicted in Figure 42. This target follows a similar path as the Emergence scenario although the renewable capacity starts to rapidly increase around 2035, which is much later than the MNRE envisions.

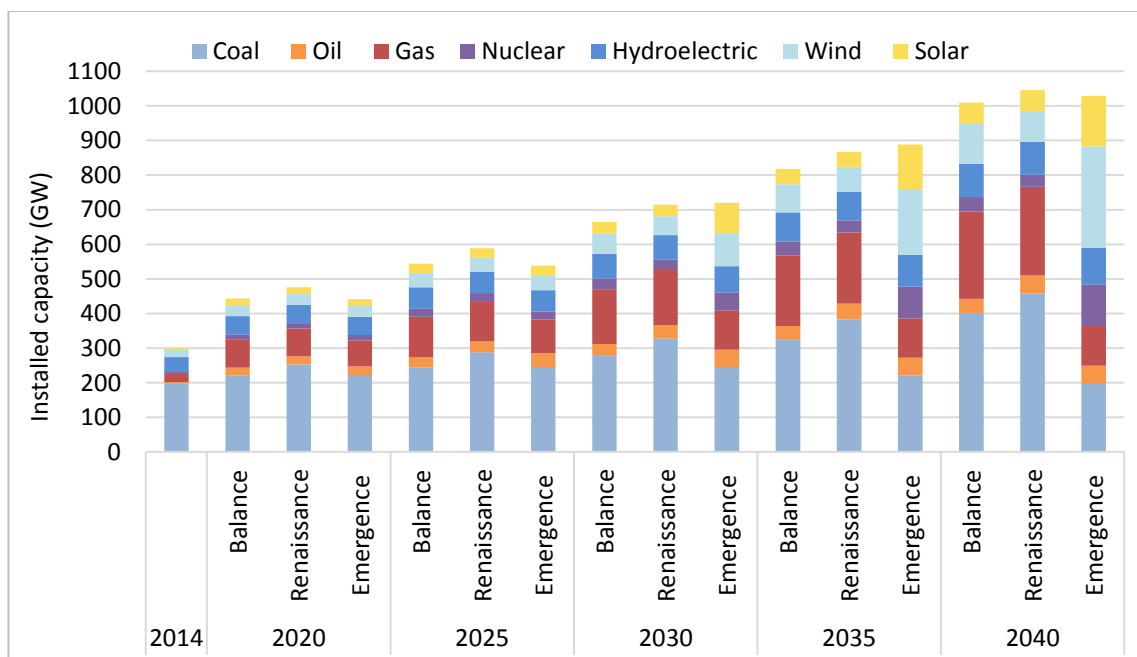


Figure 43: Future scenarios of installed capacity for India based on Enerdata's Balance, Renaissance and Emergence scenarios (Enerdata, 2014a).

Figure 43 indicates the level of renewable deployment that is predicted under the Emergence scenario and highlights the level of effort that is needed in order to stay within the global 2°C warming target compared to the Balance scenario. By 2035, low carbon energy (renewables, nuclear and hydropower) account for over 50% of the installed capacity and by 2040, low carbon sources make up 64% of capacity. This is contrasted to the Balance scenario where low carbon energy accounts for only 31% of installed capacity by 2040. Based on the MNRE renewable capacity targets, it seems as if the Indian government have the ambition to transition towards an energy mix similar to the Emergence scenario. However, the deployment of renewable energy is not occurring at a fast enough rate to reach the MNRE target by 2022.

It can be observed from Figure 43 that coal capacity under both the Balance and Renaissance scenarios is predicted to increase up to 2040. This is consistent with the government targets for capacity up to 2022. By 2030, the coal capacity starts to decline in the Emergence scenario. This seems unlikely to occur as the Indian government have not outlined any ambitions to reduce coal capacity in the future. With the Ultra Mega Power Projects scheme aiming to build a further 14 large scale coal fired power plants, coal will remain a dominant fuel for India's electricity system. The amount of natural gas based capacity in the energy mix is predicted to increase up to 2040 under the Balance and Renaissance scenarios but plays a much smaller role in the Emergence scenario. It is uncertain whether natural gas will be able to play such a large role in the energy mix given the issues with declining domestic natural gas production and limited activity on unconventional gas sources. It is assumed that in the Emergence scenario, the amount of gas capacity is reduced due to the large share of renewable generation.

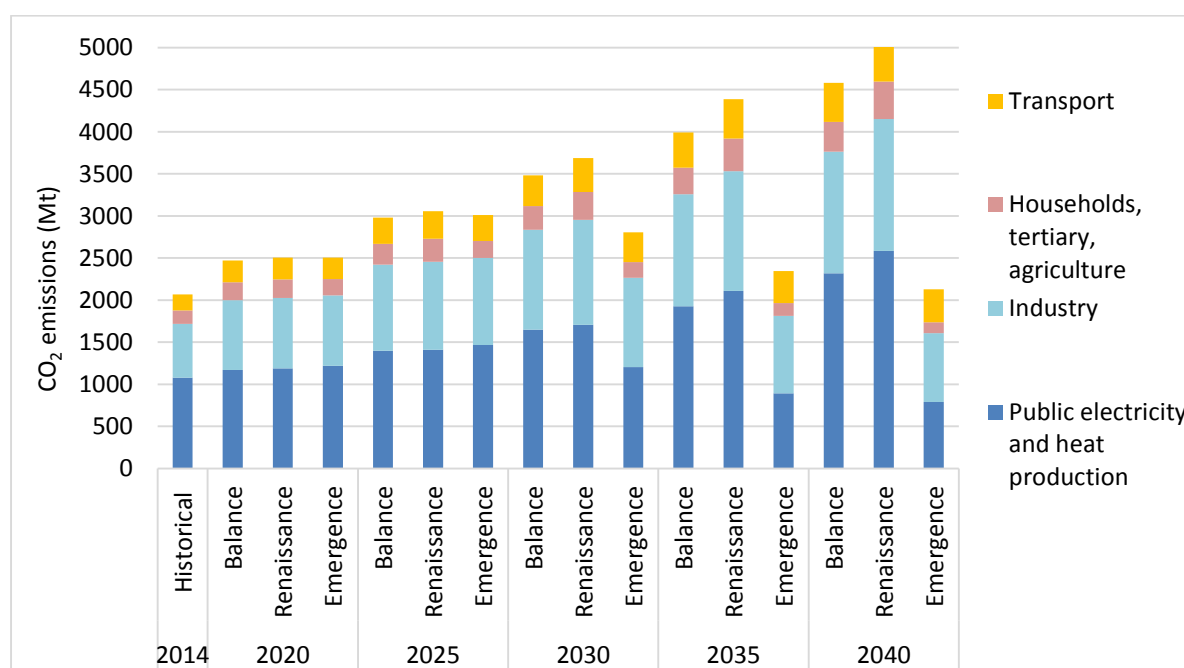


Figure 44: Projected CO₂ emissions by sector up to 2040 under each Enerdata scenario (Enerdata, 2014a).

The projected CO₂ emissions for each sector of the economy under the Enerdata scenarios is shown in Figure 44. It can be observed that public electricity and heat production continued to dominate overall emissions up to 2040 in both the Balance and Renaissance scenarios. However, due to the large deployment of renewable energy under the Emergence scenario, the emissions from public electricity and heat production are greatly reduced by 2030. Figure 44 highlights the potential emissions savings that could occur under the Emergence scenario compared to both Balance and Renaissance scenarios, which are predominantly due to the power sector. Even if the Emergence scenario is very optimistic in terms of renewable deployment and reductions in coal capacity, it gives an indication of the importance of the power sector in decarbonisation.

6.6 Summary

The power sector continues to have a significant shortfall between supply and demand, especially during peak demand hours. By consistently failing to meet capacity targets, investor confidence in government plans and ambitions is low. The multiple targets and conflicting policy documents for the power sector also creates a confusing environment for both investors and the international community. The segregated nature of government departments related to energy policies in India make the setting of capacity targets difficult and results in uncertain objectives. This is further enhanced by the federal system of governance that dictates that the state governments have high degree of control on energy policy matters. The MNRE's new renewable targets are an example of where a lack of coordination is creating uncertainty for investors in the renewable sector. The absence of communication between central government ministries as well as between state governments is a definite barrier to decarbonisation of the power sector. There is a need for an overarching comprehensive energy strategy, instead of the existing conflicting policies.

There is a lot of effort underway in India's renewable energy sector with the rapid increase in wind power deployment and the ultra-mega solar power projects under the Solar Mission. However, the new targets outlined by the MNRE seem to be very ambitious and mostly based on the ability of the Solar Mission to increase the cumulative installed capacity of solar energy to 100GW. Since the start of the Solar Mission in 2010, only one 600 MW solar park has been built in Gujarat. To reach the target of 100 GW of solar energy by 2022 will require a huge acceleration in deployment.

Despite the promising developments within the renewable energy sector, the huge growth in demand for energy in the coming years will require increasing coal and natural gas capacity in the system. The more cost effective option of coal is likely to continue to dominate thermal power generation into the foreseeable future however there are issues with the security of supply. Despite having vast coal reserves, domestic production rates are not keeping up with demand, leading to rapidly increasing imports from countries such as Indonesia and South Africa. The lack of infrastructure is also a constraint on coal supply as railways are not

sufficient to transport the coal to areas of high demand. This is discouraging for private investors as coal supplies can be disrupted or delayed during transport.

It is clear that coal will have to continue to play an important part in the electricity system. Therefore, a real opportunity exists to improve the average efficiency of coal fired power plants and facilitate the adoption of clean coal technologies. To achieve deep cuts in emissions, carbon capture and storage may be an important technology in the long term energy future. However, India will rely on financial and technological assistance from developed countries and will have to invest in a full characterisation of potential storage sites.

With the important ability to deliver peaking power capacity as well as considerably lower specific CO₂ emissions, natural gas plants could contribute greatly to emission reductions and an enhanced electricity service within India. However, the limited availability of domestic natural gas as well as the severe lack of pipeline infrastructure is a real constraint on enhancing capacity. The 50% expansion of LNG regasification terminals by 2017 will secure additional supply from the global market but the costs of LNG imports are still higher than importing coal, leading to coal power plants being favoured over natural gas. Enhancing the pipeline access to natural gas could provide a more reliable and cost effective supply of natural gas and enable an increase in the percentage of high efficiency CCGT plants. Consequently, growth in natural gas capacity could provide an important increase in the average efficiency of power plants as well as reducing the emission intensity of electricity production, which is currently the highest in the world.

Nuclear energy could provide an important low carbon base load for India's power sector. However, the progress has traditionally been very slow in this sector and there is still no commercial scale nuclear plant that can make use of India's abundant thorium reserves. It is therefore not clear if nuclear energy will be able to make up the 25% of capacity by 2050 that the government have envisioned.

Another key area for improvement is the transmission and distribution networks within the country. Improving the T&D losses from the network should be a main priority for the Indian government. A more efficient electricity network could allow the transfer of power from overproducing regions to centres of high demand and help balance out seasonal fluctuations in renewable energy generation. With a flexible and responsive grid, the full exploitation of renewable potential in each state such as hydropower in the northern states along with wind and solar energy in the western states could occur. The scale of the issue will require huge investments and coordinated, strategic planning.

7 MALAYSIA

Highlights:

- Malaysia has ambitions to become a high-income nation (as classified by the World Bank) by 2020 and have strong economic development policies in place.
- There is a voluntary target to reduce the emission intensity of GDP by 40% of the 2005 level by 2020.
- Diversifying the energy mix and securing adequate supply for power generation are key priorities due to declining domestic natural gas reserves. Malaysia will continue exporting LNG to Asian markets to gain important economic revenue.
- High potential for hydropower in Sarawak (eastern state on Borneo) is currently being developed with several large dam projects scheduled up to 2022.
- There is now an on-going shift from natural gas based generation to coal and hydropower as a result of the declining gas reserves and the readily available supply of coal from Indonesia.
- Manjung 4 is now operating and is the first ultra-supercritical (USC) coal fired power station in South East Asia. Also building the 1000 MW USC Tanjung Bin power station.
- The abundant renewable potentials of palm oil residue biomass and solar energy are not being fully exploited and renewable energy targets are not currently being met.

7.1 Background



Figure 45: Map of Malaysia showing Peninsular Malaysia and the two eastern states: Sarawak and Sabah. Adapted from (HDImage, 2015).

Malaysia has a population of 29.7 million and is split between two distinct regions separated by the South China Sea as shown in Figure 45 (WB, 2015a). Kuala Lumpur, the capital city is located on Peninsular Malaysia that has 11 states and two federal territories. Eastern Malaysia consists of two states (Sabah and Sarawak) on the island of Borneo. The country is a representative democracy with a total of thirteen states that operate according to the Federal Constitution of Malaysia, which determines the majority of national law (CIA, 2015c). Malaysia has been one of the fastest growing economies in the developing world since the 1970's when the country began the shift from an agricultural based economy to an industrialised nation. With a per capita GDP of US\$ 10,500, Malaysia is now an upper-middle income country

(according to the World Bank classification) and has maintained an annual GDP growth rate of 5.2% for the past 20 years (WB, 2015a).

Due to the vast rubber, palm oil and tin reserves within the country, Malaysia's economy was highly dependent on raw material production until the 1970s when the government introduced a diversification strategy (Saboori, Sulaiman & Mohd, 2012). The industrial sector has taken over as the main source of economic growth and the country has particular capability in the manufacturing of electronic appliances and parts for export. During this period of high growth following the 1970's, the government succeeded in bringing the poverty rate down from 50% (of people living below the international poverty line) in 1960, to less than 1% in 2014 (WB, 2015b).

7.1.1 Emissions

As a rapidly developing country, Malaysia's CO₂ emissions have risen steeply over the past 40 years. Figure 46 displays the rise in CO₂ emissions, which is well correlated with increasing GDP. It can be observed that emissions were increasing at a fairly steady rate of around 5.5% each year between 1970 and 1985. Rapid industrialisation and economic growth since the late 1980's increased the total demand for energy and resulted in an acceleration in CO₂ emissions that can be clearly observed in Figure 46. During the 10 year period between 1988 and 1998, the rate of increase in CO₂ emissions increased to 11.9% on average each year. As a comparison, during this same period global CO₂ emissions increased by an average of 1.6% annually and emissions from the EU actually declined by an average of 0.8% each year.

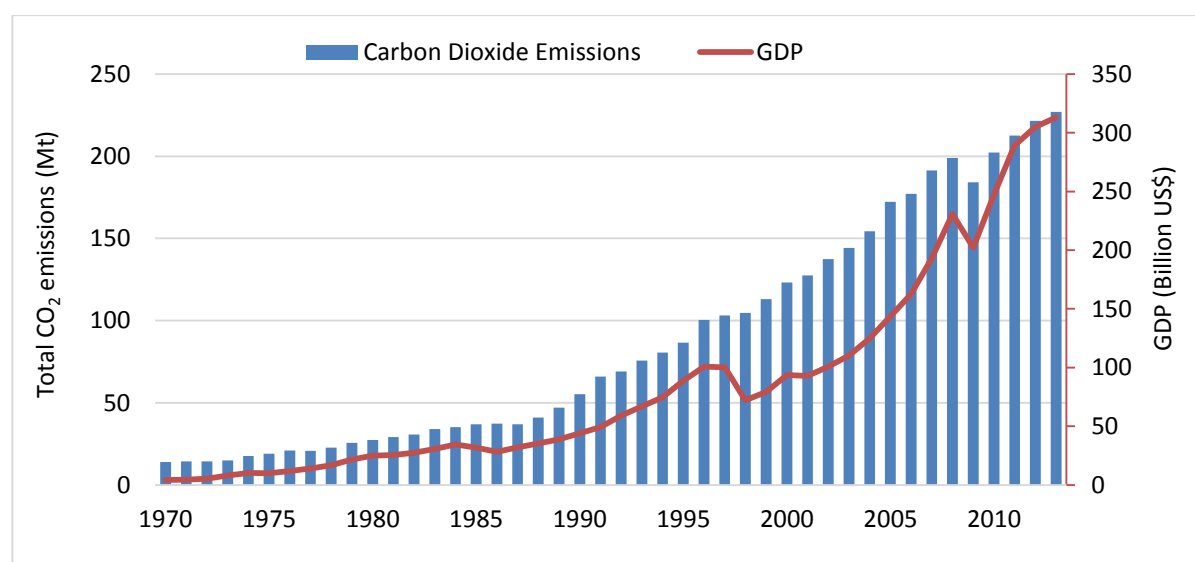


Figure 46: Total CO₂ emissions in Malaysia (EDGAR, 2014) and current GDP (Enerdata, 2014b) from 1970 to 2014.

Apart from the drop in emissions during the 2008 financial crisis, emissions have been increasing on average by 6.7% since 2000. Malaysia's CO₂ emissions of 6.8 tCO₂ per capita in 2014 are now well above the average for Asia (3.6 tCO₂/capita) and the world average of 4.3 tCO₂/capita (Enerdata, 2014a). Until the 1980's, the industrial and transport sectors were

the largest contributors to overall CO₂ emissions as shown in Figure 47. Electricity and heat production accounted for 23.6% and consisted of entirely oil-based capacity. However, with increasing levels of electrification and urbanisation throughout the country, electricity and heat production took over as the dominant source of emissions and is now the largest contributor to overall emissions, accounting for 45.7% in 2014. Within this sector, the choice of fuel has switched from oil to predominantly coal and natural gas in 2014.

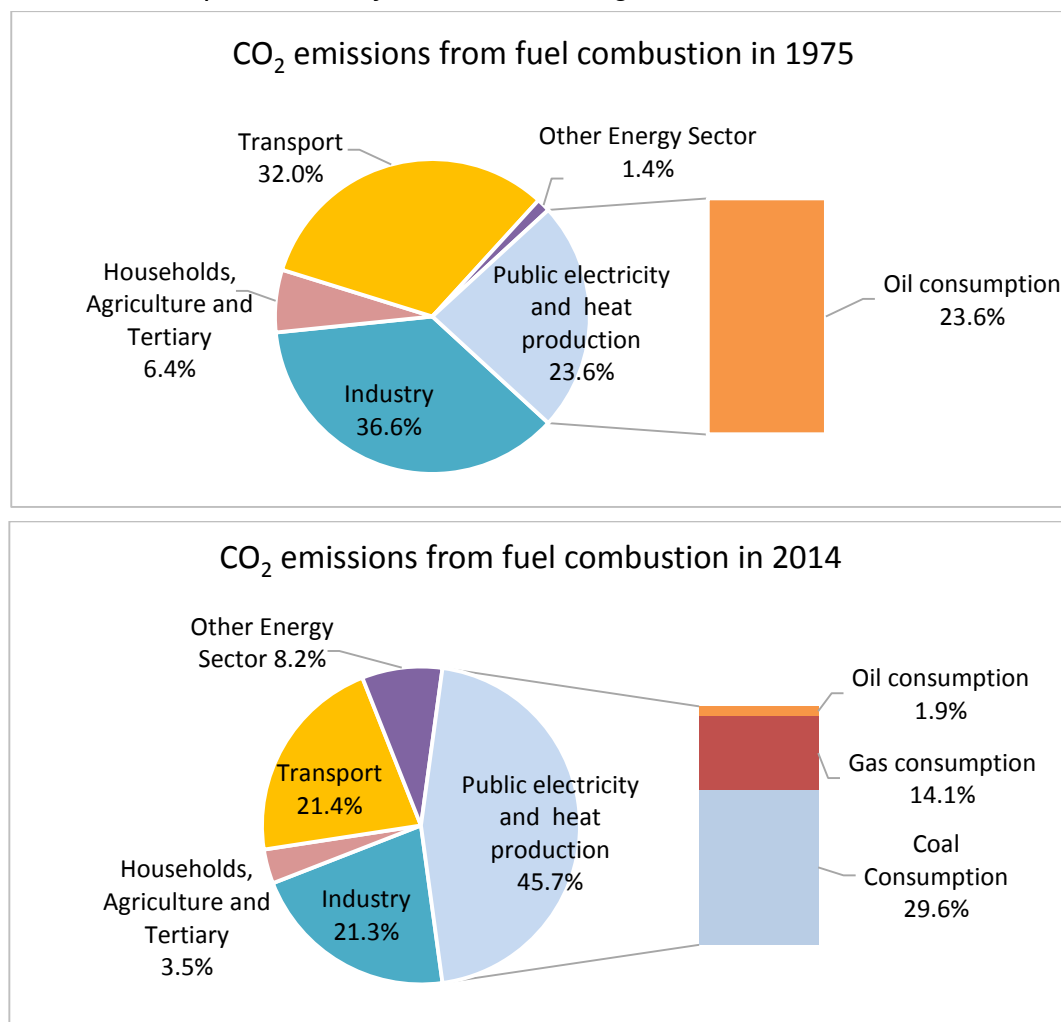


Figure 47: Comparison of CO₂ emissions by sector for Malaysia in 1975 and 2014. ‘Other energy sector’ refers to emissions from refining and fugitive sources (Enerdata, 2014a).

7.1.2 Climate Change Targets

Malaysia is a party to the UNFCCC and ratified the Kyoto Protocol in 2002. As a developing country and a non-annex I party, Malaysia has no commitments to reduce emissions under the protocol. However, at the 2009 Copenhagen climate negotiations, the Prime minister of Malaysia pledged a voluntary target to reduce the carbon emission intensity of GDP by 40% of the 2005 level by 2020 (Khor & Lalchand, 2014). This is conditional upon receiving sufficient financing for mitigation actions from developed countries. Figure 48 indicates how the emission intensity (i.e. CO₂ emissions per unit of GDP) has decreased since 1990. It can be observed that emission intensity increased up to a peak of 0.40 kgCO₂/US\$ in 2008 and has declined since. The emissions intensity in 2005 was 0.38 kgCO₂/US\$ (Enerdata, 2014a). To

achieve a reduction of 40% to meet the target, the emissions intensity would have to decrease to 0.23 kgCO₂/US\$ by 2020. For illustrative purposes, the emissions intensity has been forecast up to 2040 based on two different rates of decrease. Taking the average rate of decrease between the baseline year 2005 and 2014, gives a rate of decrease of 1.7% each year. However, if the average decrease is taken for just the years 2010-2014, the rate of decrease in emission intensity is 3%. Both of these potential rates of decrease were plotted as indicative scenarios up to 2040. It can be observed that neither rates of decrease result in the targeted emission intensity by 2020. Even with the higher 3% annual decrease, the emission intensity target is not reached until 2026. This gives an indication of the level of effort that is needed for Malaysia to reach their 40% reduction target by 2020 as the current rate of decrease is evidently not enough.

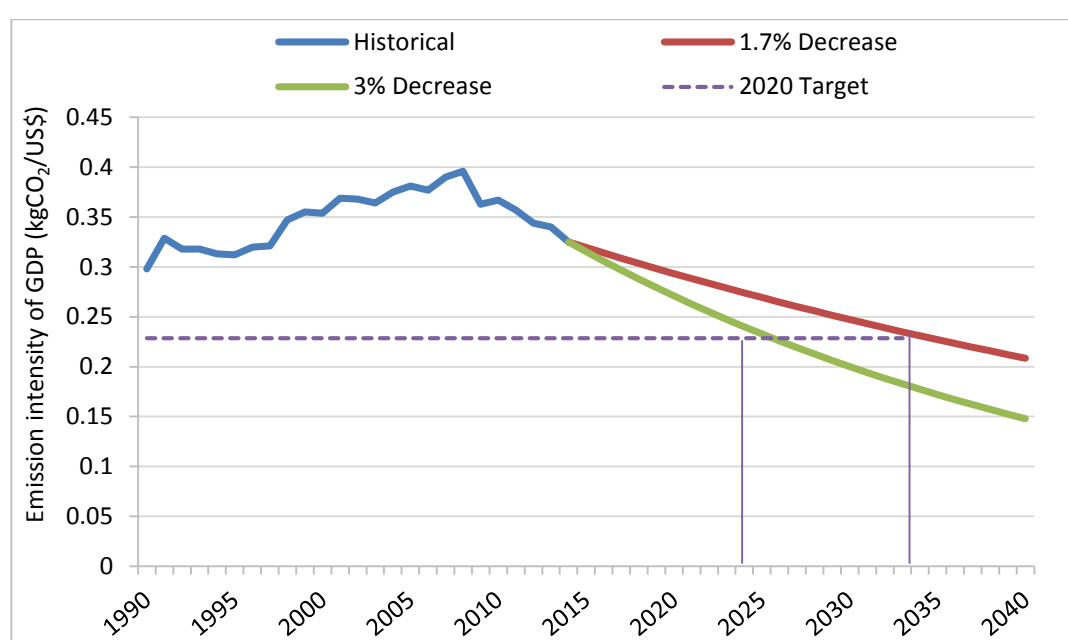


Figure 48: Historical emission intensity from 1990-2014 (Enerdata, 2014a). Two potential reduction pathways for future emission intensity are shown, along with the 2030 target.

7.2 Malaysia's Electricity System

Total consumption of electricity doubled between 2000 and 2013 as a result of continued industrialisation and economic growth. Electricity consumption per capita in 1990 was 1095 kWh/capita and has now risen by over a factor of three to 4458 kWh/capita in 2014 (Enerdata, 2014a). The majority of Malaysia's installed capacity relies heavily on fossil fuels with natural gas and coal being the dominant fuels used in electricity generation. With the total installed capacity of 32.5 GW in 2014 and a peak demand of 16.5 GW, there is a comfortable reserve margin within the electricity system (Enerdata, 2014a).

7.2.1 Electricity Market

The majority of Malaysia's population live in Peninsular Malaysia which accounts for 91% of total electricity demand in the country. Peninsular Malaysia is highly dependent on imported coal and depleting indigenous natural gas to meet its energy needs. Sarawak and Sabah

account for 5% and 4% of electricity demand respectively (Yahaya, 2014). The electrification rate within Peninsular Malaysia is high at 99% but there is less access to electricity in the more rural states of Sabah and Sarawak which have ongoing electrification programmes in place (Enerdata, 2015g). Transmission and distribution (T&D) losses across Malaysia amount to 7% of electricity distributed. This has improved greatly since the 1980's when T&D losses were above 12% (Enerdata, 2014a).

The power sector in Malaysia is split into three distinct networks for Peninsular Malaysia, Sarawak and Sabah. Three state-owned companies Tenaga Nasional Bhd. (TNB), Sarawak Energy Bhd. (SEB) and Sabah Electricity Sdn. Bhd. (SESB) monopolise the transmission and distribution systems in these respective areas (Chong & Poh, 2015). These three firms had complete control of energy generation and distribution up until 1994 when the government allowed the integration of independent power producers (IPPs) into the market. The state companies now account for 60% of electricity generation, with the rest generated by IPPs (Enerdata, 2015g). The market is still mostly vertically integrated as the IPPs generate electricity to supply to the state owned companies under Power Purchasing Agreements and there is no wholesale competition.

7.2.2 Resource Potential

Fossil Fuels

Petronas is Malaysia's national oil and gas company that owns the exploration and production rights to all oil and natural gas projects within the country, therefore controlling all licences for foreign companies (Enerdata, 2015g). The company is the largest contributor to government revenue, providing up to 45% (EIA, 2014a). Malaysia has the 4th largest oil reserves in the Asia-Pacific region, which are located mostly off-shore (EIA, 2014c). The 3.8 billion barrels of proven reserves tend to be light and sweet crude oil (BP, 2015). Domestic oil consumption has been increasing over the past decade leaving smaller volumes available for export. It is estimated that Malaysia has around 15 years of oil production remaining (Enerdata, 2015g). The government provided extensive tax allowances for investment into Enhanced Oil Recovery (EOR) and marginal field exploration activities since 2008 due to declining production rates. Shell and ExxonMobil have several on-going EOR projects in mature oil fields (EIA, 2014c). Petronas have started EOR operations at the Tapis oilfield which is the first large-scale EOR project in South East Asia (Petronas, 2014).

Although natural gas production has been slowing over the past decade, Malaysia still exports 50% of domestic natural gas, mainly through long term LNG contracts with Japan, South Korea and Taiwan (Enerdata, 2015g). Malaysia has reserves of 1.4 trillion cubic meters (tcm), which represent around 40 years of production (BP, 2015). To cope with increasing natural gas consumption over the past few years, the government is trying to encourage international oil and gas companies to facilitate enhanced exploration, particularly in deeper off-shore waters, under the Economic Transformation Programme (Khor & Lalchand, 2014). Petronas

are also developing new regasification terminals to secure supply from the global market as domestic supplies decline (EIA, 2014c).

Malaysia has some domestic coal reserves but they are mostly located in interior of Sarawak and Sabah. These areas have high associated extraction costs as they are highly forested and severely lack appropriate infrastructure. Some of the coal reserves lie in regions such as the Maliau Basin in Sabah that are designated as protected areas (APEREC, 2013a). Coal mining is occurring in Sarawak but production rates are low and the coal is of sub-bituminous rank, which is of poorer quality than internationally traded bituminous coal (IEA, 2010).

Renewables

Malaysia's geographical location in the equatorial tropics makes the installation of solar PV and solar thermal technology very favourable. Daily average solar irradiation is estimated to be around 4-5 kWh/m² (Mekhilef et al., 2012). This compares to high values of around 6.5-7 kWh/m² in parts of North Africa, the Middle East and Australia, and lower values of 2.5-3 kWh/m² in Northern Europe as seen in Figure 49. The amount of solar energy that Malaysia receives fluctuates according to the monsoon seasons, with higher irradiation occurring during the northwest monsoon (Mekhilef et al., 2012). Figure 50 indicates the average annual solar irradiation that Malaysia receives, with higher annual radiation exhibited in the northeast state of Sabah. Ahmad and Tahar (2014) estimated that a potential 6500 MW of capacity could come from the installation of solar PV technology in Malaysia.

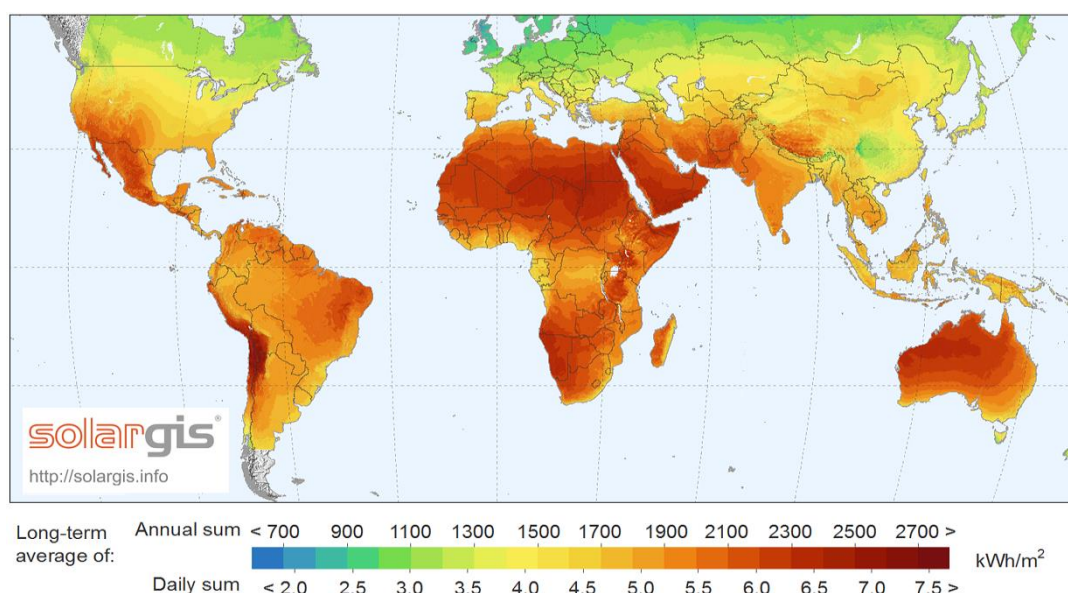


Figure 49: World map of Global Horizontal Irradiation (GHI). GHI is the sum of direct horizontal irradiation and diffuse horizontal irradiation (SolarGIS, 2013).

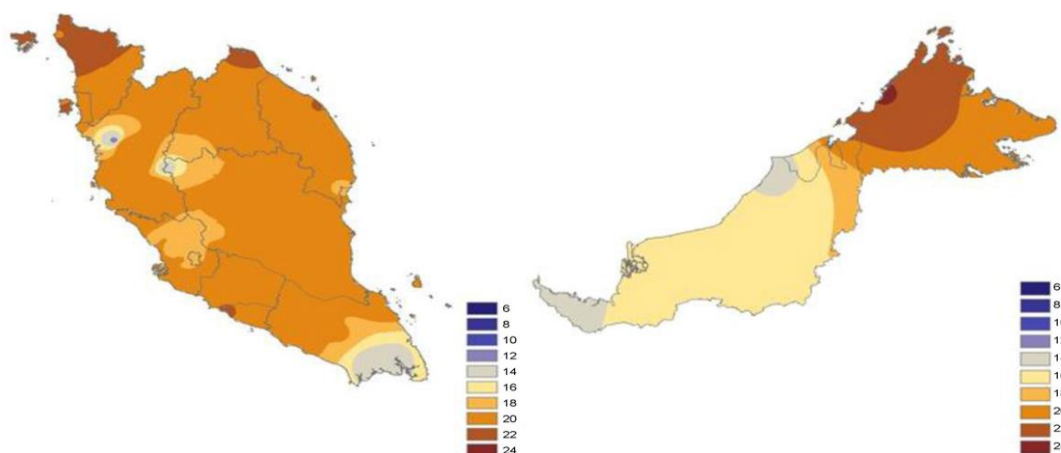


Figure 50: Map of average annual solar irradiation in Malaysia in MJ/m² per day (Mekhilef et al., 2012).

Malaysia's renewable energy source with the highest potential is often stated to be waste biomass from the wood and palm oil industries (Enerdata, 2015g). Malaysia has 4.9 million hectares of palm oil plantations and is the second largest producer of palm oil globally (MPOB, 2011). The majority of palm oil is exported for refining in other countries such as Singapore. The waste from one hectare of palm oil plantation can reach 50-70 tonnes, which can be utilised for generating electricity or producing biofuels. When other sources of waste biomass are included, the total potential for this renewable energy source is estimated to be 29 GW (Ahmad & Tahar, 2014).

Owing to its higher population density and larger demand for energy, Peninsular Malaysia has already exploited the majority of its hydropower potential. However, the eastern states of Sarawak and Sabah have had much less investment into hydroelectric power. Sarawak has considerable potential for hydropower development due to its favourable geography and high levels of rainfall. Estimates for the full capacity of hydropower in Sarawak are as high as 28 GW but there are a number of complicated environmental and social issues involved with realising this potential (Ali, Daut & Taib, 2012). One of the largest hydroelectric projects in Malaysia is the 2400 MW Bakun Dam (located in Sarawak) that was completed in 2014 (Enerdata, 2015g). The dam, controlled entirely by the Ministry of Finance, was the source of much controversy as it required the relocation of 10,000 indigenous people and flooded over 700 km² of rainforest and farmland (Pei Ling, 2013).

Malaysia has unfavourable meteorological conditions for wind energy as its geographical location is not conducive for high wind speeds. There is a higher potential for off-shore wind farms. However with the additional risk of tropical cyclones, there has been very little uptake of this technology in Malaysia (Ahmad & Tahar, 2014).

7.2.3 Energy Trade

Malaysia is the second largest exporter of LNG globally after Qatar, accounting for 11% of the world's exports (BP, 2015). Malaysia exports from the Bintulu terminal as seen in Figure 51 and over half of the LNG exports go to Japan with 21 long-term contracts in place (Enerdata, 2015g). With declining reserves of natural gas available for power generation, Petronas has developed a LNG regasification terminal at Melaka with a capacity of 3.8Mt/year that will import LNG from Qatar and Australia. There are also plans to build a second terminal that is expected to be operational by 2018 (LNG Journal, 2014).

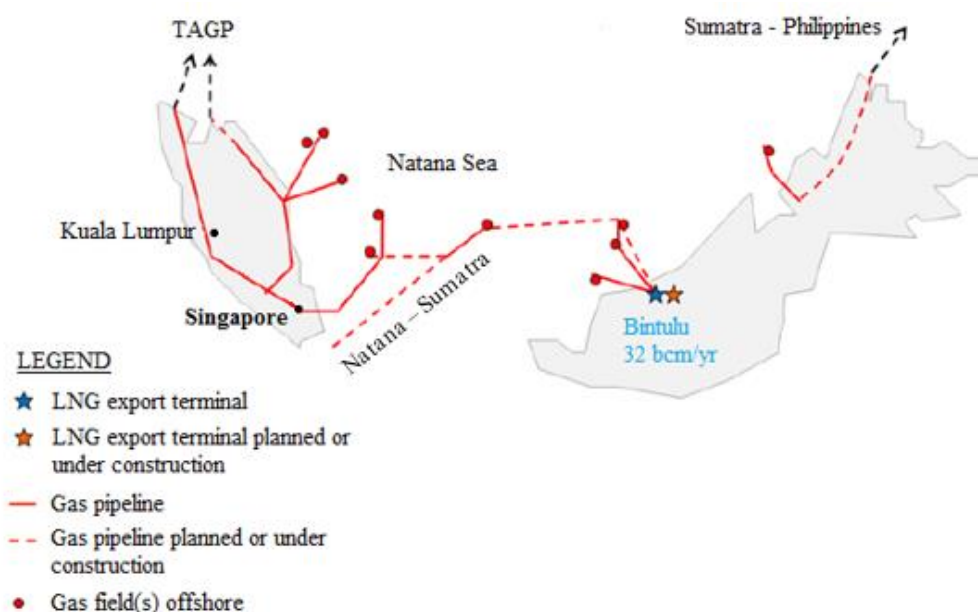


Figure 51: Map of existing and planned gas infrastructure (Enerdata, 2015g).

Peninsular Malaysia has an extensive gas pipeline network with number of pipelines linking off-shore fields with the mainland. Singapore is also connected to Malaysia via a pipeline leading to exports of 1.6 billion cubic metres (bcm) per year (Enerdata, 2015g). The development of a trans-national gas pipeline network in South East Asia is being promoted by the Association of South East Asian Nations (ASEAN). The trans-ASEAN Gas Pipeline scheme aims to link major centres of consumption and supply across 10 countries by 2024 (ASEAN, 2013). There is a proposed pipeline linking Sabah to the Philippines as observed in Figure 51.

Malaysia exports around half of its crude oil due to the high quality to Asia-Pacific markets (namely India, Australia and Japan) and imports lower cost heavy crude for its refineries (EIA, 2014a). Malaysia built up its refining capacity steadily after being reliant on Singapore for many years and can now meet the majority of domestic demand for petroleum products through its five refineries. Petronas is developing an integrated refinery and petrochemical plant in the state of Johor in order to further enhance Malaysia's position as an important player in the Asian petroleum markets (Enerdata, 2015g).

Coal is currently being mined in Sarawak but production rates are low due to the difficulties associated with mining in this region, leading to 90% of coal supply needing to be imported (Ali, Daut & Taib, 2012). The majority of coal is imported from Indonesia (accounted for 73% of imports in 2011) as well as Australia and South Africa (Singh Gill, 2013). Imports have doubled in the past five years (EIA, 2014a).

The electricity grid in Peninsular Malaysia has interconnectors with Thailand and Singapore and there are also three planned connections from Sarawak to Indonesia, Brunei and Peninsular Malaysia under the ASEAN Power Grid project (EIA, 2014c). The Power Grid programme aims to develop fourteen interconnection projects between South East Asian countries to optimise the utilisation of domestic resources (ASEAN, 2012).

7.3 Energy Policy and Drivers

7.3.1 Structure of the Energy Administration

There are several government departments that are concerned with energy policy within Malaysia. The energy division of the Economic Planning Unit (EPU) is the planning body responsible for formulating energy policies for the country and reports directly to the Prime Minister (EIA, 2014c). The Ministry of Energy, Green Technology and Water (KeTTHA) prepares policies for the electricity sector including all renewable and energy conservation policies (Enerdata, 2015g). The EPU and KeTTHA govern the electricity supply for Peninsular Malaysia and the state of Sabah. The Energy Commission was set up in 2001 and is the independent regulator for the electricity sector and the natural gas industry for these regions. The Energy Commission does not regulate the electricity sector in Sarawak as the state government has total control over policies, regulation and operation of power infrastructure in this region (Chong & Poh, 2015).

7.3.2 Energy Policies

Malaysian energy policy has traditionally been focused on the effective utilisation of domestic fossil fuel supplies and diversification of fuel sources, having been heavily reliant on natural gas and oil for many years (Basri, Ramli & Aliyu, 2015). The Four Fuel Diversification Strategy was initiated in 1981 with the motivation to introduce coal and hydropower into the generation mix, in order to have an optimised balance in energy supply (Ali, Daut & Taib, 2012). Diversification has continued to be a key component of recent energy policy with the introduction of the Five Fuel Diversification Strategy in 2001. This recognised renewable energy as a 'fifth fuel' along with oil, gas, hydro and coal. This policy outlined how using palm oil and the associated waste products for power generation could be further developed for the country, as well as utilising landfill biogas, solar PV, wind and mini-hydro (Khor & Lalchand, 2014).

National Development Policies

The EPU develop the Five Year Plans that set out the economic development goals and major infrastructure improvements for Malaysia (Enerdata, 2015g). They cover key aspects of national development as well as energy policies and initiatives. Under the 9th Malaysia Plan, five transformation corridors within the country were identified as a part of an effort to improve economic and social development in the more remote parts of the country. Three of these corridors are located in Peninsular Malaysia, with two situated in Sarawak and Sabah: the Sarawak Corridor of Renewable Energy (SCORE) and the Sabah Development Corridor (SDC). The SCORE project places a large emphasis on developing hydropower in Sarawak to provide cost effective power to attract manufacturing and energy intensive industries to the state (Shirley & Kammen, 2015).

The New Economic Model was initiated in 2010, which has the overall objective for Malaysia to reach high income status (as classified by the World Bank) by 2020 (WB, 2015b). The programme has four strategic pillars that underpin this national transformation. One aspect is the Economic Transformation Program in which 12 National Key Economic Areas (NKEAs) were identified. The oil, gas and energy sectors are represented as one of these NKEAs due to their large contribution to GDP. It is estimated that these combined sectors represented US\$ 33.2 billion (or 19% of GDP) in 2009 (EPU, 2010).

The New Energy Policy 2010 places emphasis on five important areas of the energy system. Initiatives include reforming energy pricing, diversifying energy supply, improving regulation within the energy sector and encouraging the adoption of energy conservation initiatives (Basri, Ramli & Aliyu, 2015). A focus of this policy is the continued diversification of generation capacity through the development of alternative sources of energy (mainly hydropower, coal and LNG) and the steady shift towards a competitive market based system. Nuclear energy may become an option for Peninsular Malaysia after 2020 following a detailed feasibility study.

The 11th Malaysia Plan (2016-2020) outlines ten strategic areas for economic development towards the government's goal of becoming a high income country by 2020. Energy specific initiatives include: creation of a comprehensive demand side management plan, increasing the renewable energy capacity to 7.8% of total capacity and promotion of smart grid technology (EPU, 2015).

Fossil Fuel Subsidy Reforms

The government of Malaysia has initiated a number of fossil fuel subsidy reforms over the past five years. In 2010, the Malaysian government initiated a subsidy reform programme for oil and petroleum products in order to alleviate some of the pressure on its fiscal deficit. It was estimated that in 2013, around US\$ 7.9 billion had been allocated to fuel subsidies (Bridel & Lontoh, 2014). The subsidy cuts undertaken by the government under the reform programme were expected to save US\$ 1 billion in 2013 (Enerdata, 2015g). However, subsidies had only partially been reformed as of 2014 making this value seem optimistic (Bridel & Lontoh, 2014).

In 2011, electricity tariffs were raised by 7.1% on average to try and reduce expenditure on subsidies that the government provides through its state companies (EIA, 2014c). In the same year, the government initiated a price reform for domestic natural gas and coal tariffs that aimed to increase prices to similar levels as the international market. It took three years before subsidies were reduced but finally in 2014, the subsidies were reduced for both coal and natural gas leading to a number of consumer price increases. There was an 11% increase in gas prices for households and a 20% increase for the commercial and industrial sectors (EIA, 2014c). The price of power production increased on average by 15% in Peninsular Malaysia (EIA, 2014c).

Renewable Energy Policies

The Small Renewable Energy Power (SREP) programme was introduced in 2001 to develop the renewable sector in Malaysia and to encourage private investment in small projects (Petinrin & Shaaban, 2015). Licences under the scheme allowed up to a maximum of 10 MW of power for sale to the national power utilities in Malaysia (EIA, 2014c). Progress was very slow and ineffective under this project, leading to the development of the National Renewable Energy Policy and Action Plan (NREPAP).

The NREPAP was introduced under the 10th Malaysia Plan that ran from 2011 to 2015 (Basri, Ramli & Aliyu, 2015). The NREPAP established the Renewable Energy Act in 2011, which introduced a Feed-in-Tariff (FiT) for electricity generated from renewable sources (Enerdata, 2015g). The Sustainable Energy Development Authority (SEDA) was set up as a result of the Renewable Energy Act to oversee the implementation of the FiT. This policy has been successful in providing incentives for producers and stimulating the renewable energy sector but much work is still needed as renewable energy currently makes up less than 1% of generating capacity.

The National Biofuel Policy in 2006 introduced a 5% blend requirement with diesel petroleum and there are plans to increase this to 7% (EIA, 2014c). The National Biomass Strategy was introduced in 2011, which outlined how the use of biomass waste for biofuels could be better managed and developed towards 2020 (Khor & Lalchand, 2014). As Malaysia is the world's largest producer of palm oil, there was a particular emphasis on the palm oil industry and the associated waste biomass that could be effectively used to generate bioenergy or process into bioethanol.

Energy Efficiency

Energy efficiency and conservation (EE&C) policies have been growing in importance over the past 30 years. The National Energy Efficiency Action Plan (NEEAP) was finalised in 2014 and outlines five key initiatives that will be implemented including an electrical appliance labelling program and a green-building rating tool. The NEEAP has a target to reduce the overall electricity consumption by 10% by 2020 (Khor & Lalchand, 2014). Under the National

Green Technology Policy launched in 2009, the Green Building Index was developed. All new developments must meet certain standards for energy efficiency, sustainable site planning and water efficiency (APEREC, 2013a). All the policies discussed above are summarised in Table 18.

Table 17: Summary of important energy policies in Malaysia

Date	Policy	Details
1981	Four-fuel Diversification Strategy	Diversification of energy sources, including gas and hydro in the generation mix
2001	Five- fuel Diversification Strategy	Recognised renewable energy as a fifth fuel
2006	National Biofuel Policy	Developing the potential for advanced and second generation biofuels (mainly palm oil)
2009	Green Technology Policy	Stimulating the green market, advocating more efficient biomass cogeneration plants
2010	10 th Malaysia Plan (2011-2015)	<i>National Renewable Energy Policy and Action Plan</i> : Supporting the growth of the renewable energy industry
		<i>New Energy Policy</i> : Enhancing security of supply, extending EE&C initiatives
	New Economic Model	Enable Malaysia to become a high income nation by 2020
2011	Renewable Energy Act	Established a FiT for renewable energy
	National Biomass Strategy	Waste biomass to energy applications
2015	11 th Malaysia Plan (2016-2020)	Green growth for sustainability and resilience

7.4 Current Generation Capacity

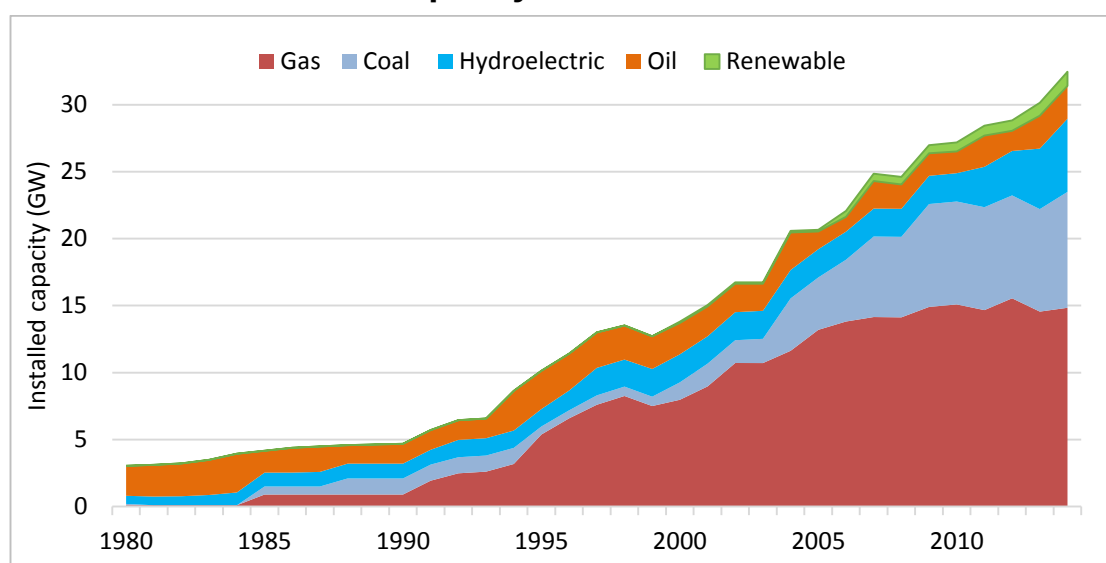


Figure 52: Historical changes in the installed capacity for Malaysia from 1980-2014 (Enerdata, 2014a).

Historically, the electricity generation mix was dominated by oil owing to Malaysia's large domestic reserves. Following the discovery of off-shore natural gas reserves in 1982 and diversification policies enacted by the government, hydro-powered dams and natural gas fired power plants began to gain importance in the electricity mix. Natural gas and coal are currently the dominant fuels for generation accounting for 72% of the total 32.5 GW of capacity (Enerdata, 2015g). Figure 52 indicates the importance of natural gas for electricity since the 1990s and the dominance of fossil fuels within the generation mix. Malaysia currently has 21 gas-fired power plants, which make up 46% of the generating capacity.

It can be observed from Figure 52 that the percentage of coal-fired generation in Malaysia's electricity system has increased rapidly over the past 10 years. This is as a result of a number of drivers. Policies initiated over the past decade to reduce the dependence on natural gas due to declining production rates have resulted in the coal generating capacity increasing from 9.4% in 2000 to 26.6% in 2012 (Enerdata, 2014a). Coal also has a very competitive cost for electricity production leaving natural gas and oil to be sold at premium export prices, generating important revenue for Malaysia (Ali, Daut & Taib, 2012).

Manjung 4, the first ultra-supercritical coal fired power plant constructed in South East Asia by Alstom, started operating in April 2015. The 1000 MW plant is situated on the same site as the 2100 MW Manjung subcritical coal fired power station that was commissioned in 2003 and benefits from the proximity of the Lekir coal import terminal (Alstom, 2012). The new Manjung 4 unit is stated to be around 40% efficient with low NO_x burners and a seawater flue gas desulphurisation unit that absorbs 90% of SO₂ emissions (Alstom, 2012). The 40% efficiency of Manjung 4 is a vast improvement on the existing Manjung power station but is not the

highest efficiency that an ultra-supercritical plant can achieve, as state of the art ultra-supercritical plants can have thermal efficiencies of up to 48-50% (WCA, 2015).

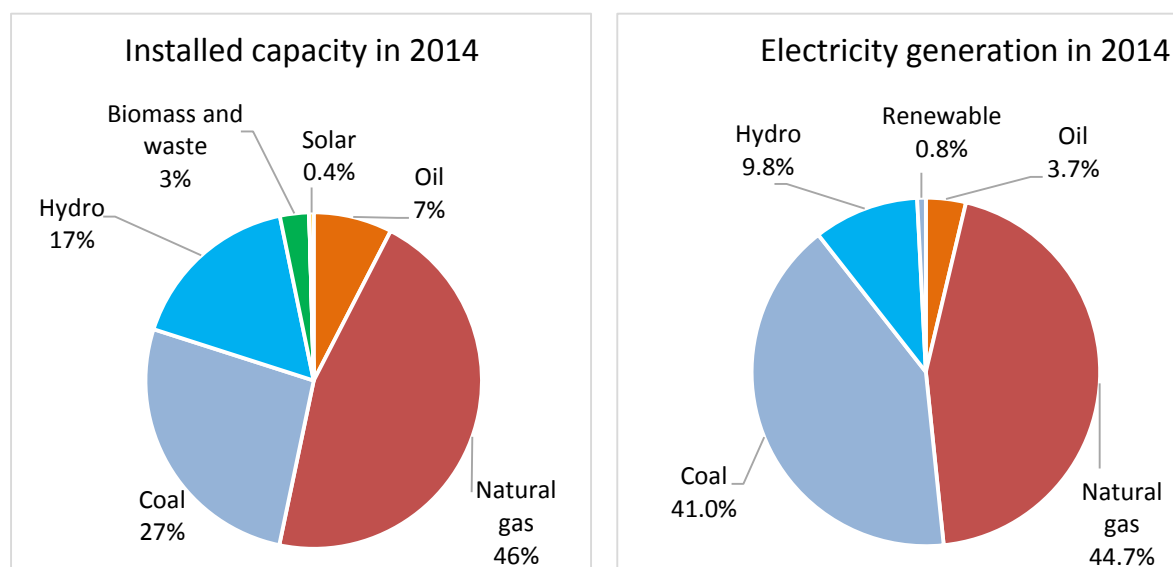


Figure 53: Comparison of installed electricity and electricity generation by fuel in Malaysia in 2014 (Enerdata, 2014a).

Figure 53 indicates that coal makes up a much larger percentage of electricity generation than of the installed capacity. This is due to the fact that there are natural gas plants still accounted for in the capacity but are not actually generating electricity due to supply constraints and cost issues.

Hydro-electric power plants currently account for 17% of the Malaysia's installed capacity as seen in Figure 53. Hydro-electricity production has doubled over the past 15 years increasing from 6970 GWh in 2000 to 14800 GWh in 2014 (Enerdata, 2014a). The majority of these hydropower stations are located in Peninsular Malaysia but increasing hydro-development is occurring in the eastern states with a number of large schemes coming on line in the next few years.

With the launch of SEDA's FiT in 2011, there has been a considerable growth in activity within the renewable sector. In 2012, a solar park with capacity of 8 MW developed by Cypark Resources Berhad started operating in Pakam, a small town near Kuala Lumpur (Cypark, 2012). In 2014, the largest solar power project in the country with a capacity of 10.25 MW was commissioned by Amcorp (Kuncinas, 2014). Data from SEDA gives a breakdown of the different types of renewable electricity generated and can be seen in Figure 54. Generation from renewable sources increased rapidly from 2012 to 2014 but still only accounted for 0.8% of the total electricity generation (as seen previously in Figure 53).

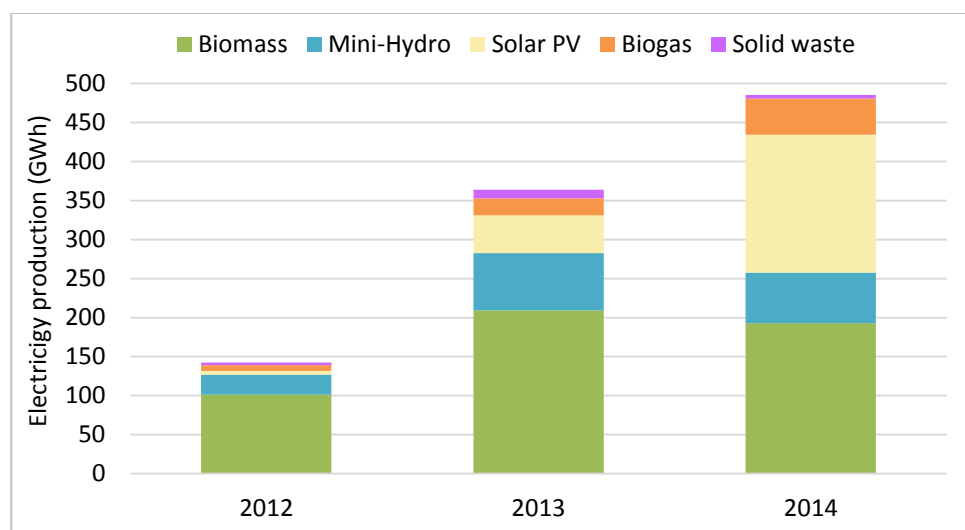


Figure 54: Electricity generation from renewable sources for the 2012- 2014 under the FiT scheme initiated in the Renewable Energy Act 2011 (SEDA, 2015).

7.5 Discussion and Analysis

7.5.1 Government Projected Capacity

As Malaysia's economy continues to develop under the Economic Transformation Programme, electricity demand is expected to grow at 2.6% annually up to 2030 (Yahaya, 2014). With the declining production rates from domestic natural gas reserves, the government has anticipated the shift towards other fuels such as coal and LNG obtained from the global market. Due to the high associated costs of LNG (i.e. building regasification terminals, cost of liquefaction and freight transport), coal is the preferred option in the longer term. Coal powered plants account for around half of the planned capacity additions for the 11th Malaysia Plan period (2016-2020).

The Energy Commission publish an annual 'Electricity Supply Outlook' for Peninsular Malaysia and Sabah which outline the projected electricity demand and planned power stations up to 2022. The Energy Commission does not publish an outlook for Sarawak as they are not the electricity system regulator for this state. The details of planned capacity for the separate regions of Peninsular Malaysia, Sabah and Sarawak are outlined below.

Capacity Additions in Peninsular Malaysia

As Peninsular Malaysia accounts for 91% of electricity demand in the country and holds the majority of installed capacity, the capacity additions for this region have a large impact on the country's electricity system as a whole. With the retirement of 240 MW of thermal generation in 2014 and increasing electricity demand, the reserve margin for Peninsular Malaysia has reduced from 31% to 23% (EC, 2014a). The government is trying to combat this tightening of the gap between supply and demand of electricity through rapidly expanding the capacity base.

5000 MW of coal projects are in the planning stages for Peninsular Malaysia for the period 2015 to 2023, including the new ultra-supercritical plant at Tanjung Bin (see Table 18). The Energy Commission estimate that by 2020, coal based power generation will make up 64% of total installed capacity and coal consumption will increase from the current 21 million metric tonnes to 40 million metric tonnes per year (EC, 2014a). The government recognises the need to use 'clean coal' technology to reduce CO₂ emissions from the power sector but only two plants in Malaysia will be using ultra-supercritical boilers by 2017.

Table 18: New generation projects for Peninsular Malaysia (EC, 2014a).

Fuel Type	Project	Capacity (MW)	Commercial Operation Date
Coal	Tanjung Bin Energy	1000	Mar 2016
	TNB Manjung Five	1000	Oct 2017
	TNB Jimah East Power	1000	Unit 1: Nov 2018
		1000	Unit 2: May 2019
	Other coal	1000	2023
Gas	CBPS Redevelopment	384	Sept 2015
	TNB Prai	1071	Jan 2016
	Pengerang Co-Generation	400	June 2017
	S.J. Jambatan Connaught extension	300	Dec 2018
	New CCGT	1000	2018
		1000	2021
Hydro	TNB Hulu Terengganu	250	Sept 2015
	TNB Ulu Jelai	372	Mar 2016
	Hulu Terengganu (Tembat)	15	Dec 2016
	Additional Chenderoh	12	Oct 2018
	Tekai	156	Dec 2020
	Telom	132	Dec 2022
Import	Sarawak Interconnection	2000	2024
TOTAL		12,092	Up to 2024

There have been plans since 1996 to export electricity from Sarawak to Peninsular Malaysia via a 2000 MW submarine interconnector cable but progress has been halted many times due to cost issues. The project is now going ahead but it is unlikely that the cable will be operational before 2024 (EC, 2014a; Kumar, 2014) and there are no guarantees towards this date given the history of the proposals. The Energy Commission are relying heavily on this cable being in place by 2024 (it is included in Table 18) and expect that it will provide up to 10% of electricity generation when operational (EC, 2014a).

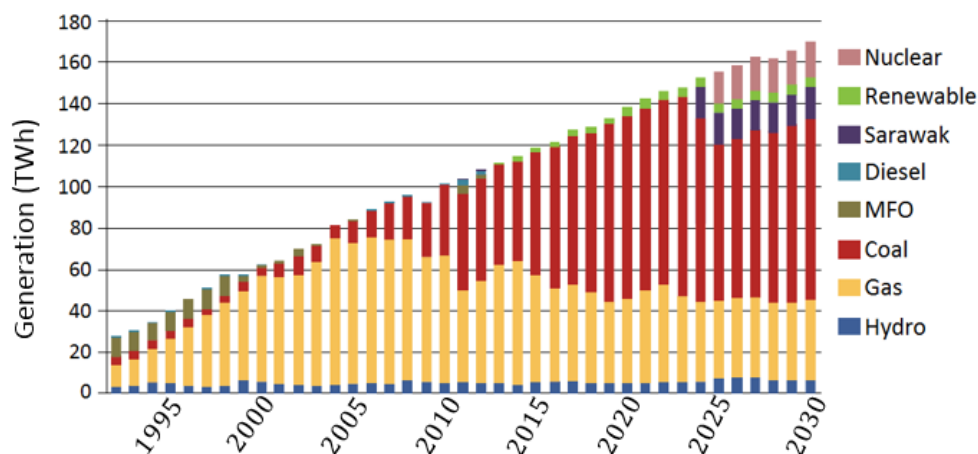


Figure 55: Projected generation mix for Peninsular Malaysia up to 2030 (EC, 2014a).

Growth in electricity generation is expected to be around 3% each year up to 2023 and this projected increase in generation can be observed in Figure 55, which outlines the Energy Commission's projected generation mix for Peninsular Malaysia. Sarawak is shown as an energy source due to the potential for exporting coal and hydropower through the electricity interconnector that is expected. The increasing proportion of coal within electricity generation along with declining importance of natural gas can be observed. The Energy Commission predict that renewable energy capacity will reach 750 MW for Peninsular Malaysia by 2025 but this would still only account for 3% of generation.

It can be observed that nuclear energy enters the generation mix in 2025. Nuclear energy is being considered as one of the options for meeting Peninsular Malaysia's electricity demand after 2020 as stated in the New Energy Policy (2010). The deployment of nuclear energy for power generation is a distinct scheme under the Economic Transformation Programme with the creation of the Malaysia Nuclear Power Corporation (MNPC) (Ibrahim, 2014a). The MNPC envisage a 2000 MW twin-unit nuclear plant with the first unit being operational by 2021. However there are many barriers to overcome before this becomes a reality. Public acceptance of nuclear energy as an option is low (Caballero et al., 2014) and there are concerns over the transparency of the feasibility study that the government has commissioned (Basri, Ramli & Aliyu, 2015).

Capacity Additions in Sabah

Peak demand in Sabah was 874 MW in 2013 whilst total dependable capacity was 1172 MW meaning that there is a comfortable reserve margin (EC, 2013). However, there is a regional imbalance between the supply and demand of electricity in Sabah. The west coast has the majority of the gas based generating capacity (63% of total capacity) whilst the east coast relies on aging, highly inefficient diesel-fired plants. Peak demand for electricity from 2014-2023 is expected to grow at a rate of 5.13% per annum, reaching 1562 MW in 2023 (EC, 2014b).

There has been a rural electrification scheme in place for many years, aiming to improve the standard of living within rural communities. The electrification rate has now reached 90% (EC, 2014b). An interconnector line was completed in 2007 to supply electricity from the west to the east coast but this is primarily a backup service to the local generators and there are still concerns over the reliability and efficiency of generation in the east (Chong & Poh, 2015). The government is therefore planning several new plants in the east to even out this disparity (see Table 19).

Table 19: New generation projects for Sabah.

Fuel Type	Project	Capacity (MW)	Commercial Operation Date
LNG	Eastern Sabah Power Consortium	300	2017 (under review)
Gas	Kilmanis Power Plant	385	190MW already commissioned Third unit in 2015
	CCGT	180	2019
	CCGT	100	50MW by 2021 50MW by 2022
Hydro	SREP Afie Power	9	2015 (Under Review)
	S.J. Tenom Pangi (Upgrade)	8	2015
	Upper Padas HEP	180	2023
Biomass	SREP Eco-Biomass	20	2014 (under review)
	SREP Kalansa	5	2015 (under review)
Geothermal	SREP Tawau Green Energy	30	May 2016
Imports	Sarawak 275kV cable	100	2023
TOTAL		1317	Up to 2023

The Sabah government plans to retire all east coast oil based generation after the completion of the 180 MW combined cycle gas turbine (CCGT) plant in 2019 and most of the new capacity planned is natural gas. 75 MW of renewable capacity is currently under construction in Sabah with a focus on biomass and hydropower. The medium sized Upper Padas 180 MW hydro project is envisioned for 2023. In the long term, a 275 kV cable implemented between Sipitang and Lawas in northern Sarawak will allow Sabah to utilise electricity transferred from Sarawak.

Capacity Additions in Sarawak

Capacity expansion in Sarawak is focused around exploiting the large hydropower potential of the state as well as constructing coal fired power stations. Sarawak Energy Bhd. (SEB) have announced that they will be building five new coal fired power plants, adding 2400 MW of capacity to the state (see Table 20). The first of these power stations will be operational in 2018 (Enerdata, 2015g).

Table 20: New generation projects for Sarawak (based on Sarawak Energy upcoming projects and (Sovacool & Bulan, 2012)).

Fuel Type	Project	Capacity (MW)	Commercial Operation Date
Hydro	Murum hydroelectric project	944	Unit 1: December 2014 Fully operational – end of 2015
	Pelagus	411	2015
	Baram hydroelectric project	1200	Construction starting 2015
	Limbang 1 and 2	245	Construction starting 2018
	Baleh	1295	Construction starting 2019
	Others	930	Construction starting after 2022
Coal	Balingian I	600	2018
	Balingian II	300	2019
	Mukah West I	600	-
	Mukah West II	600	-
	Merit Pila	300	2022
TOTAL		7425	Up to 2022

Total installed capacity in Sarawak was 3132 MW in 2013. 1332MW is from SEB projects and 1800 MW is from the Bakun Dam (EC, 2013). Bakun is owned by Sarawak Hydro Sdn. Bhd. (a central government owned subsidiary) and is currently running at just 50% capacity due to lack of electricity demand (the dam is designed to be 2400 MW in total capacity) (EC, 2013). The peak demand in Sarawak is only 1466 MW meaning that there is around a 115% reserve margin even with only half the capacity from Bakun. This is extremely high compared to the rest of Malaysia that operates with around a 30% reserve margin (Shirley & Kammen, 2015).

As one of the development corridor projects in Malaysia, the Sarawak Corridor of Renewable Energy (SCORE) is aiming to attract investment from key sectors such as the petrochemicals, aluminium and steel industries. The project has the ambition to grow the state's economy by a factor of 5 and targets US\$ 105 billion of investment by 2030 (Sovacool & Bulan, 2012). The attraction of these energy intensive industries to Sarawak is based upon the capacity to supply low-cost electricity from large hydropower and new coal plants. The programme outlines that 20 GW of hydropower will be developed in Sarawak in the long term. By 2030, it is estimated that at least 12 hydroelectric dams will be built (Shirley & Kammen, 2015).

SEB are planning two large dams; the Baram Dam which is 1200 MW and Baleh Dam of 1295 MW size. This is in addition to a number of smaller schemes as outlined in Table 20. The Baleh Dam has been approved by the Natural Resources and Environment Board but there has been a lot of opposition to the Baram Dam as it would displace up to 20,000 people (Wong & Sibon, 2015). There have been ongoing conflicts surrounding the development of large dams in Sarawak since the Bakun Dam was constructed, displacing 10,000 indigenous people (Pei Ling, 2013). The poor environmental and social management of this project has been a driver of civil discontent in the area. The 12 proposed hydropower projects under the SCORE project would result in flooding of an estimated 2425km² of forest. This represents a loss of ecologically significant land as Borneo has one of the highest levels of biodiversity in South East Asia (Shirley & Kammen, 2015).

Even with the expected increase in electricity demand from the SCORE industrial projects, it is unclear as to why the Sarawak state government is going ahead with the 12 proposed hydropower stations and five new coal plants when there is currently so much extra capacity that is not needed and such a high reserve margin. The state will not be able to export electricity to Peninsular Malaysia, which could really benefit from this extra capacity, for at least another 10 years. With the controversy surrounding the building of large dams in this region, the state government may have to reconsider their generation strategy to include more sustainable, renewable energy sources.

Total Capacity Additions for Malaysia

Based on Tables 18, 19 and 20, the majority of capacity additions for the whole country are observed to be coal power plants and hydropower schemes. The total planned capacity additions for Malaysia are outlined in Table 21. This includes gas plants planned to utilise the new LNG capacity that will be available after the construction of the second regasification terminal in 2018. Table 21 does not include the renewable capacity that is intended under SEDA's FiT.

Table 21: Total capacity additions in Malaysia excluding renewable generation under the FiT.

Total capacity additions for Malaysia 2015-2024 (MW)	
Coal	7400
Gas	5120
Hydro	6159
Renewable	55

Box 2: Carbon Capture and Storage in Malaysia

With over 7 GW of coal plants in the planning stage, the Malaysian government are committing their power sector to be highly dependent on fossil fuels for the foreseeable future. Carbon Capture and Storage (CCS) could therefore become an important CO₂ abatement technology for Malaysia. The direct capture of CO₂ from large point sources such as a power station and subsequent storage in a geological formation has the potential to greatly reduce emissions. There is a considerable amount of EOR activity underway in Malaysian oil fields and these represent opportunities for CO₂ storage. Under the Clean Development Mechanism (CDM) of the Kyoto Protocol, Petronas proposed a project in 2006 to recover CO₂ from the Bintulu LNG complex and inject it into a saline aquifer in the Sarawak Basin (Petronas, 2006). There have been on-going concerns over the viability of CCS projects being eligible under the CDM but a decision was made in 2011 to allow CCS to be included in this mechanism (DEHSt, 2012). KeTTHA have also recently partnered with the Global CCS Institute with a view to developing a Malaysian CCS Capacity Development Programme. CCS is evidently gaining interest within Malaysia although it is still in the very early development stage.

7.5.2 Overall Renewable Capacity Targets and Additions

The Malaysian government aimed to increase renewable capacity (excluding large hydropower) to 975 MW by 2015 under the NREPAP. This was an ambitious target that is not likely to be reached by the end of this year as the installed capacity was only 325 MW at the beginning of 2015 (SEDA, 2015). The NREPAP also outlined targets towards 2050 that are shown in Table 22 with the majority of the capacity increases expected from biomass and solar energy. KeTTHA announced that solar energy is anticipated to play a very important role for Malaysia's electricity system in the long term (KeTTHA, 2008). However, the cumulative installed capacity of solar PV technology was only 205MW at the beginning of 2015 (SEDA, 2015).

Table 22: Renewable energy targets and resulting CO₂ emission reductions from the National Renewable Energy Policy and Action Plan (NREPAP) (KeTTHA, 2008).

Year ending	Cumulative total renewable capacity (MW)	Annual renewable generation (GWh)	Renewable generation of total electricity generated (%)	Annual CO ₂ emissions avoided (Mt)
2015	975	5374	5	3.38
2020	2065	11227	9	7.07
2030	3484	16512	10	10.4
2050	11544	25579	13	16.1

Given the slow development of renewable energy so far, it seems unlikely that these targets will be reached without a real acceleration in the deployment of new capacity. The FiT

established under the Renewable Energy Act (2011) has stimulated the renewable energy market which can be seen in Figure 54 which shows a marked increase in generation between 2012 and 2014. However, the rate of deployment of renewable energy is too slow as the target for 2015 has not even nearly been met.

7.5.3 APERC Projected Capacity

APERC developed two main scenarios in their modelling: the Business as Usual (BaU) scenario is based on existing policies and the High Gas (HGS) scenario takes into account the impacts of higher natural gas production rates in the APEC region. The natural gas production rates for Malaysia are predicted to increase by 36% by 2035 under this scenario which includes the commercialisation of new gas fields and an increase in production rates from existing fields (APERC, 2013a). In the APERC model, Malaysia's GDP is predicted to be US\$ 576 billion (USD at Purchasing Power Parity (PPP)) in 2020 and US\$ 1 trillion in 2035 with a GDP growth rate of 4%.

The Malaysian government has been actively pursuing strategies to diversify the generation mix so as to not be reliant on one single energy source. Therefore, in the HGS scenario it is assumed that with higher gas production rates, Malaysia would maximise economic gains by exporting the additional gas through its pipeline connections and extensive LNG facilities. Natural gas would not be used in the electricity sector, so the electricity generation mix is predicted to be very similar under both scenarios and can be seen in Figure 56.

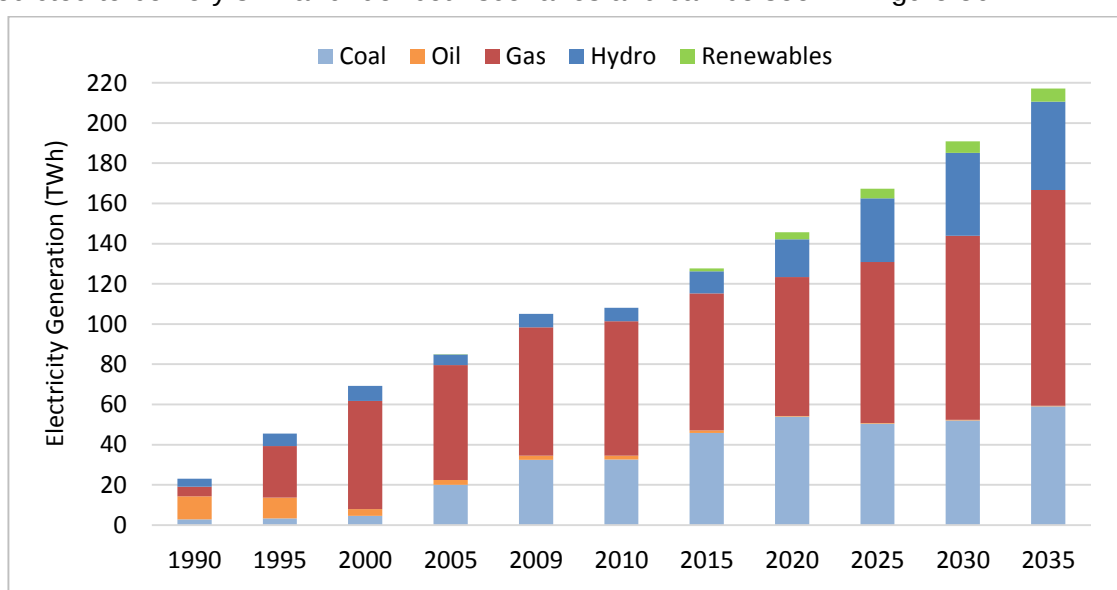


Figure 56: Predicted electricity generation by fuel up to 2035 under both the BaU and HGS scenarios (APERC, 2013b).

The APERC predicted generation mix differs slightly from the government projections. The Energy Commission estimated that 64% of Peninsular Malaysia's installed capacity would be made up of coal based generation in 2020. This compares to APERC's projection of coal only making up 37% of Malaysia's total generation in 2020 and the generation remains stable around 60 TWh until 2035 (APERC, 2013b). Using Enerdata's statistics, coal generation

actually reached 62 TWh in 2014 (Enerdata, 2014a). This indicates that APERC's values are slightly out of date as they are projecting from 2009 historical values of generation. Even taking the approximate proportions of APERC's projections, it is unlikely that electricity generation from coal will remain stable as 7400 MW of coal capacity is planned for Peninsular Malaysia and Sarawak up to 2023.

The increasing importance of hydropower observed in APERC's projections after 2020 is consistent with government projections of the increased installed hydro capacity in Malaysia, with 6159 MW scheduled for construction in the period 2015-2024. The renewable generation is predicted to make up 3% of the total electricity generation by 2030 which is similar to the government's projections in this period.

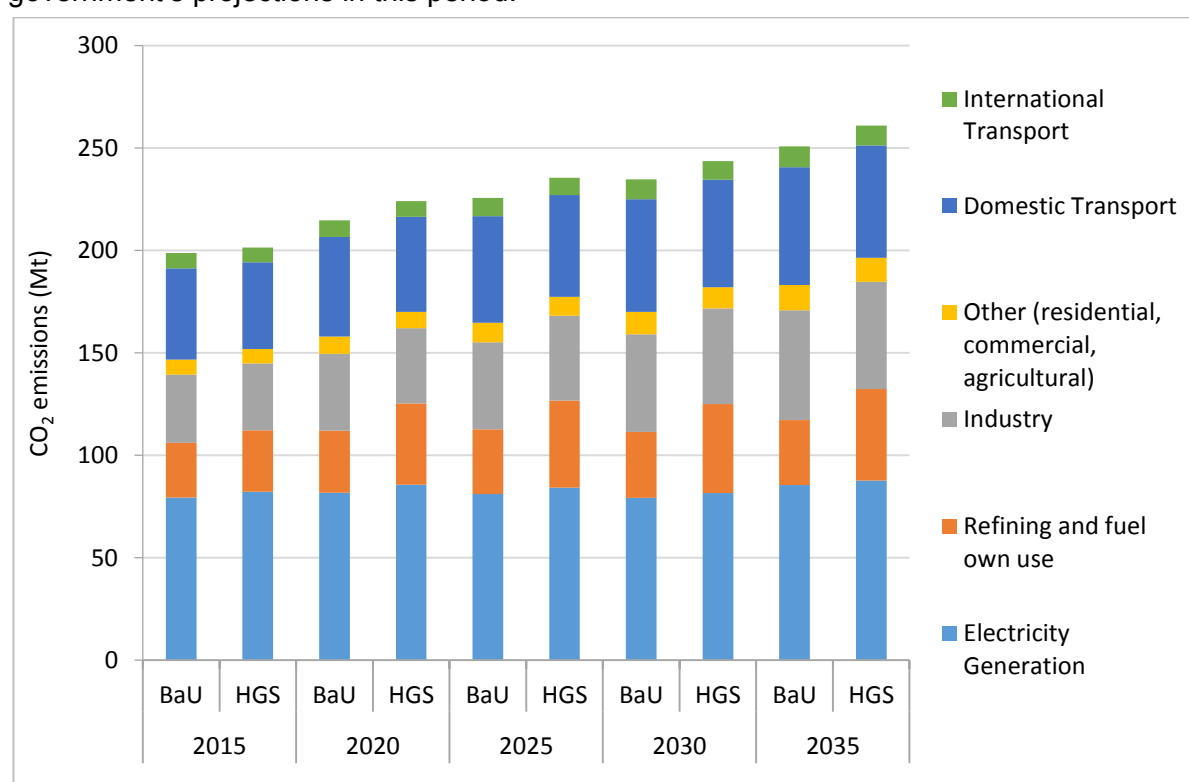


Figure 57: Projected CO₂ emissions by sector under the Business as Usual (BaU) and High Gas (HGS) scenarios (APERC, 2013b).

The predicted CO₂ emissions from each scenario can be observed in Figure 57. Both scenarios predict a similar increase in total CO₂ emissions up to 2035 and the relative contributions of each sector are quite similar under each scenario. However, there is a slight increase in the CO₂ emissions from refining under the HGS scenario. This is due to the assumption that the additional gas production under this scenario would not be used in the power sector. It would instead be exported for economic profit, therefore increasing refining activity and associated CO₂ emissions. Under both scenarios, CO₂ emissions from the electricity sector do not show a marked increase over the modelled period. This seems unusual given the government's plans outlined new coal plants during this period. The apparent shift in Malaysia's electricity system away from natural gas based to coal generation

would result in increased emissions from the power sector if no mitigation technology is deployed, due to the higher carbon intensity of coal fired power plants.

7.5.4 Low Carbon Asia Research Group Projected Capacity

The Low Carbon Asia Research Group (LCARG) conducted a study aiming to develop low carbon society scenarios for Asian Regions including Malaysia. The study uses the Asia-Pacific Integrated Model (AIM) to project potential greenhouse gas emission reductions in various sectors of the economy under different scenarios. Three scenarios for projecting potential greenhouse gas emission reductions in Malaysia were developed: Business as Usual (BaU). Existing (EXT) and Alternative Planning (APS). The BaU scenario assumes development without introduction of low carbon measures. The EXT scenario uses current policies to project capacity and the APS scenario involves a more intensive implementation of low carbon measures (LCARG, 2013). Table 23 outlines the low carbon measures implemented under each scenario that are related to the energy sector.

Table 23: Low carbon measures implemented under each scenario for 2020 and 2030 (LCARG, 2013).

Low Carbon Measures <i>Scenario</i>	2020		2030	
	<i>EXT</i>	<i>APS</i>	<i>EXT</i>	<i>APS</i>
Percentage of technology replaced with higher efficiency types in energy demand sectors (%)	40	60	75	85
Renewable energy in power supply (MW)	2080	4160	4160	10400

The estimates for the amount of renewable capacity in the power sector are based on the NREPAP targets for the EXT scenario, and extrapolated for the APS scenario. Energy efficiency measures play an important role in the potential emission reductions for both the EXT and APS scenarios, especially by 2030. Figure 58 indicates the predicted share of the generating capacity under each scenario for 2020 and 2030. It can be observed that the share of coal capacity in generation will increase up to 2030 under all scenarios. This is in line with government capacity plans. Nuclear energy is projected to enter the generation mix in 2030 under EXT and APS scenarios, which is consistent with the government's long term vision. However, there has been a history of public opposition towards nuclear power in Malaysia and the planning process has been criticised for insufficient public engagement. Therefore it will not be surprising if nuclear power projects are halted due to public concerns.

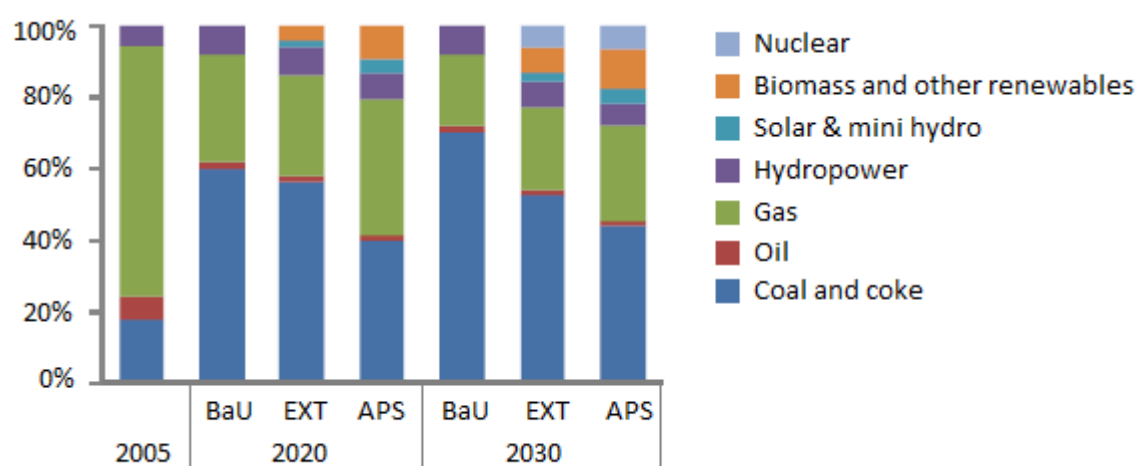


Figure 58: Predicted share of power supply by energy source under the three scenarios BaU, EXT and APS. 2005 is the base year for these projections (LCARG, 2013).

Under the current policies scenario (EXT), renewable capacity accounts for 10% of the total installed capacity by 2030. This contrasts to the APERC scenarios where renewable capacity would only reach 3% by 2030. This is reflective of the fact that the renewable capacity targets in the EXT scenario are based on the ambitious NREPP targets outlined by the Malaysian government. Table 23 indicates that renewable capacity would have to reach 4 GW by 2020 and then 10.4 GW by 2030. These are very ambitious targets given that only 1 GW of renewable capacity had been installed as of 2014.

Malaysia's total greenhouse gas emissions were also predicted under each scenario. Figure 59 indicates that under the BaU scenario, emissions rise to 741 MtCO_{2eq} by 2030 (compared to 2005 levels of 271 MtCO_{2eq}). Under the EXT scenario, emissions increase to 429 MtCO_{2eq} and the APS scenario leads to emissions of 360 MtCO_{2eq}. In Figure 59, the emissions intensity of GDP is shown to decrease from the 2005 level under the EXT and APS scenarios, although APS is the only scenario that achieves the 40% reduction target by 2020 set out by the Malaysian government. This indicates the level of effort required to reach this target as the current policies scenario (EXT) results in only a 20% decrease in emissions intensity by 2020. Under BaU, the emissions intensity increases to 2020 and then decreases by only 16% towards 2030. It is therefore apparent that as the share of coal capacity in the electricity system seems very likely to increase, even more effort will be required to reduce the emissions intensity, as a result of these increased emissions from the power sector.

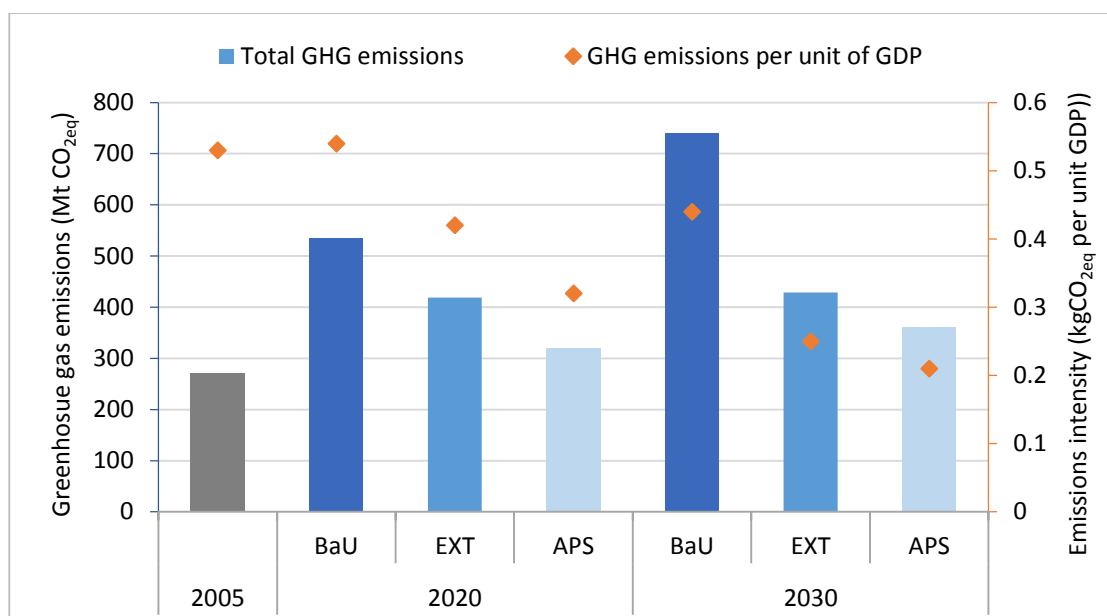


Figure 59: Projected greenhouse gas (GHG) emissions under the BaU, EXT and APS scenarios for 2020 and 2030. 2005 levels are the baseline year. GHG emissions intensity is also plotted on the secondary axis (LCARG, 2013).

It is important to note that GDP is expected to keep increasing as Malaysia tries to reach its ambitions of becoming a high income country by 2020. If GDP increases at a faster rate than is projected in the AIM model, then the emissions intensity may appear to reduce by more than is just occurring through fuel switching and energy efficiency measures. This further highlights the issues associated with a country having an emission intensity goal as absolute emissions can still increase whilst meeting the target.

Figure 60 gives an overview of the scenarios discussed throughout this section. A scenario developed by Khor and Lalchland (2014) is also shown as a comparison. The majority of the scenarios are seen to diverge from the Enerdata historical data which gives an indication of the variation in capacity values between sources. The dominance of thermal generation can be observed in Figure 60 as the scenarios are clustered around the high thermal area of the plot. Nuclear is predicted to enter the generation mix under the LCARG Existing (EXT), Alternative Planning (APS) and Klor & Lalchland scenarios. The influence of this increase in firm low carbon capacity can be observed in Figure 60. The LCARG EXT and APS scenarios seem to indicate a larger proportion of renewable capacity than other scenarios which is due to the fact that the renewable targets included in these scenarios are based on the ambitious government targets that are unlikely to be met by 2030. The LCARG BaU scenario projects a very high dominance of thermal capacity to continue up to 2030 with limited renewables or firm low carbon capacity. With the large hydropower expansion plans, the percentage of firm low carbon looks very likely to increase which would shift this trajectory from its current position.

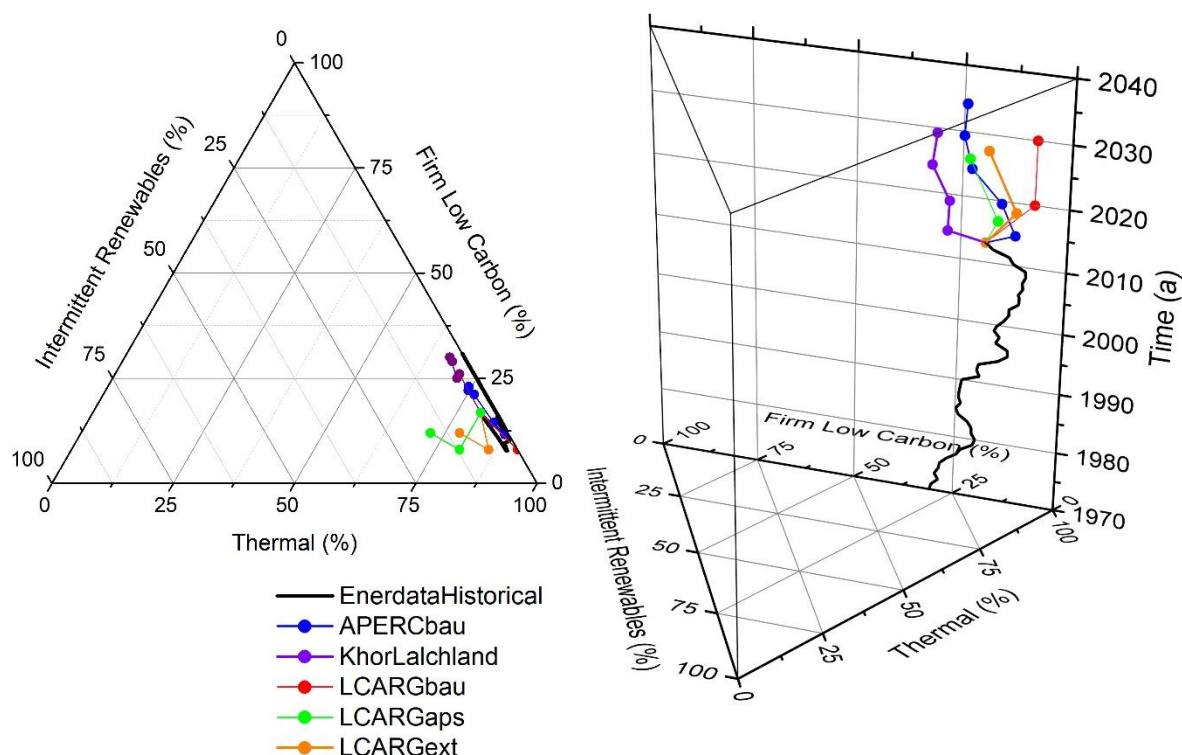


Figure 60: Malaysia's projected capacity scenarios based on APERC's BaU scenario (APERC, 2013b), Khor and Lalchland (Khor&Lalchland, 2014) and the Low Carbon Asia Research Group (LCARG) scenarios: Business as Usual (BaU), Existing (EXT) and Alternative Planning (APS) (LCARG, 2013).

7.6 Summary

Overall, energy security remains the top priority for the Malaysian government. The decarbonisation of the energy sector is evidently not a main concern with the majority of capacity additions consisting of coal fired power stations. With the availability of a stable supply of competitively priced coal from Indonesia whilst natural gas reserves decline, it is not surprising that Malaysia's electricity system is shifting away from natural gas as the main fuel. This shift toward a much more carbon intensive coal is a step in the wrong direction for meeting any kind of emissions reduction target. Even with the two ultra-supercritical coal power plants commissioned by 2016, the majority of the coal fleet will be made up of less efficient, subcritical power plants. There is some interest in CCS within Malaysia with a scoping study underway, however the concept is still in its infancy in this country. There are also major cost implications to consider with the adoption of this technology and Malaysia would likely rely on technology transfer from countries with stronger R&D capabilities.

The government recognised renewable energy as the 'fifth fuel' under the 2001 Five Fuel Diversification Strategy but there has yet to be a realisation of the large renewable potential within the country. Although there has been a recent increase in renewable capacity, the additions have not been sufficient to meet the 2015 target set out by the government. The disappointing outcome of the Small Renewable Energy Power programme initiated in 2001 meant that renewable deployment has only just picked up as a result of the Renewable Energy Act and the FiT launched in 2011. There has been considerable improvement in the sector

under this policy but the rate of deployment is still too slow to meet any of the NREPAP's ambitious renewable targets by 2020.

There is a lack of clarity in energy policy and targets between the three distinct transmission grids of Malaysia in Peninsular Malaysia, Sabah and Sarawak. There are multiple entities involved in the creation and implementation of energy policies within the country and there is a need for a coordinating body to ensure effective application of new policies in each state of Malaysia. The Energy Commission are well positioned to be this organisation but they do not regulate the electricity system in Sarawak. The fact that Sarawak is not regulated by the Energy Commission creates difficulties when trying to gain an understanding of the whole country's capacity targets and plans. There is a real need for an integrated electricity sector plan, rather than having separate plans for the different regions.

The lack of coordination and adequate planning procedures is evident from the interconnector project that has failed repeatedly to gain funding and start construction. The huge capacity expansion plans in Sarawak are based upon this interconnector going ahead as there is currently a huge excess of generating capacity within the state, even with additional demand from the SCORE industries. It is therefore integral that the interconnection project has the sufficient financial strategy in place so that delays do not continue to occur. It is also important that the Sarawak state government do not over compensate in terms of capacity, due to the large hydropower potential. The complex issues and public opposition surrounding the building of large dams should be factors considered when proposing new hydropower for the region. The introduction of many energy intensive industries to Sarawak and the coal power stations to provide for them, indicates that climate focused objectives are not high on the agenda for the Sarawak state government.

The projections of emission intensity reductions in the LCARG modelling have indicated that current policies are not sufficient for meeting the 40% reduction on 2005 levels by 2020. The most ambitious APS scenario reached the emission intensity target but only as a result of dramatically increasing renewable capacity and almost widespread implementation of energy efficient technologies within the energy sector. Both of these are unlikely to occur in the period leading up to 2030 under current rates of deployment. Even if Malaysia manages to achieve their target of reducing the emission intensity of GDP by 40% of the 2005 level by 2020, this does not necessarily ensure a reduction in absolute emissions. Malaysia is aiming to become a high income nation by 2020, meaning that its GDP will continue to rise and will skew the emission intensity value. With the electricity system shifting towards being more heavily focused on coal generation, it seems improbable that the power sector emissions will level out as suggested in APREC's projections. Coal will likely become a dominant presence in the energy system and will contribute greatly to power sector CO₂ emissions. Ultimately, reducing emissions intensity may still be achievable in other sectors through energy efficiency measures but the power sector is unlikely to contribute to this.

8 SINGAPORE

Highlights:

- Singapore is a high-income country ranked 5th in the world in terms of its GDP per capita of \$78,760 (\$US on a purchasing power parity basis).
- Singapore has submitted their INDC and pledged to reduce their emission intensity by 36% from 2005 levels by 2030. Energy efficiency policies are the key strategy promoted by the government for reaching the emission intensity target.
- APERC modelling estimate the emission intensity to decline up to 2035 but it is unclear whether Singapore's energy efficiency policies will be enough to meet the target.
- Singapore is almost completely dependent on imports, as they have no domestic fossil fuel resources. The electricity capacity has shifted from mainly oil-based to natural gas since the mid-1990s. New LNG regasification terminals are under construction to diversify supply.
- With peak demand of only 6,770 MW and installed capacity reaching 12,890 MW in 2015, the electricity system is reliable and has a high reserve margin.
- Solar energy is the renewable source with the highest potential as well as increasing the number of waste-to-energy plants. There are strong R&D capabilities within solar energy sector but slow deployment with only 33.1 MW of PV installations by 2014.

8.1 Background



Figure 61: Map of Singapore showing the location of Jurong Island in the south west. Adapted from (OCHA, 2013).

Singapore is a high-income country, located at the southern tip of the Malaysian Peninsula as seen in Figure 61. As a highly urbanised state, Singapore has the second highest population density in the world with a population of 5.5 million living within a land area of only 710 km² (WB, 2015a). After gaining independence from Malaysia in 1965, the economy started to grow under the responsibility of the Economic Development Board (EDB). The EDB initiated a program of rapid industrialisation with a vision of establishing Singapore as a global hub for

business and investment. Singapore is now a successful free-market economy and is one of the world's leading oil and petroleum trading centres (APEREC, 2013a). The petrochemicals industry is an important part of the economy, accounting for 5% of GDP in 2013 (IEA, 2013). The country has a strong manufacturing sector and depends significantly on exports, particularly I.T. services, consumer electronics, pharmaceuticals and medical technologies (CIA, 2015b). Singapore is currently ranked 5th in the world in terms of its GDP per capita (US\$ PPP) of US\$ 78,760 (Enerdata, 2014a).

8.1.1 Emissions

The change in Singapore's total CO₂ emissions from fuel combustion since 1970 can be seen in Figure 62 along with the increasing GDP. Singapore's CO₂ emissions increased gradually between 1970 and 1986 with an average percentage increase of 6.2% each year during that period. The rate of increase in emissions accelerated between 1987 and 1995 to 10.2% on average each year, which correlates to the increasing GDP at the time. Following this acceleration period, absolute CO₂ emissions have fluctuated around an average value of 41 MtCO₂ between 2000 and 2013. The rate of emissions increase has slowed to an average of 1.3% each year during this period despite GDP increasing rapidly. This is lower than the global rate of CO₂ emissions increase which was 2.5% on average each year between 2000 and 2013.

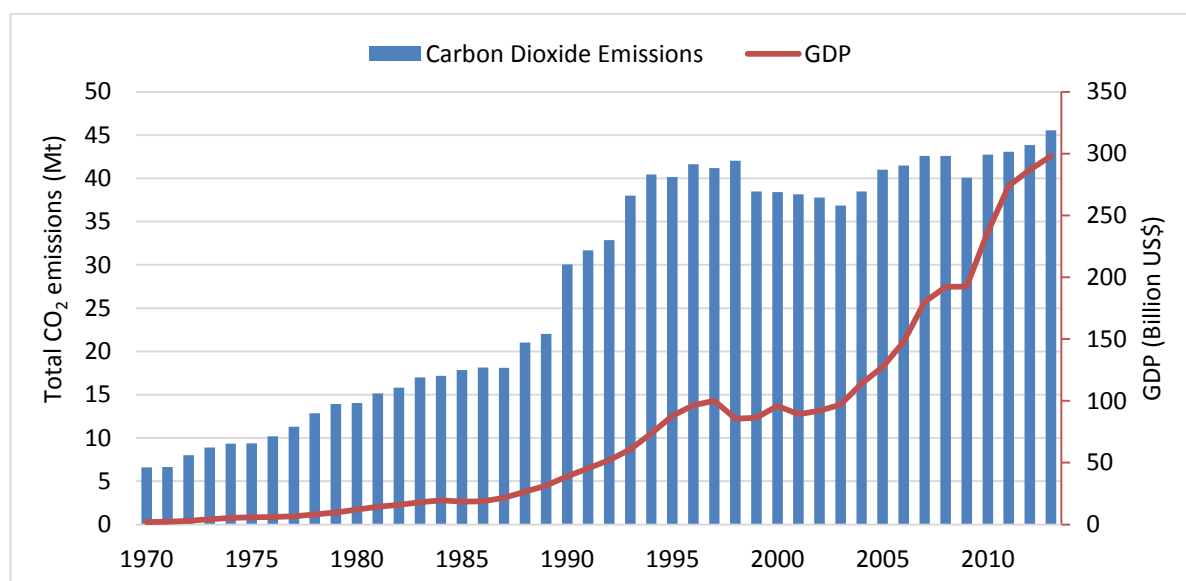


Figure 62: Total CO₂ emissions from fuel combustion in Singapore (EDGAR, 2014) and current GDP (Enerdata, 2014a) from 1970 to 2014.

CO₂ emissions have plateaued in recent years and Singapore currently contributes 0.1% to global emissions (NCCS, 2015). However Singapore ranks much higher globally in terms of its per capita CO₂ emissions. In 2014, Singapore's per capita CO₂ emissions reached 9.5 tCO₂/capita, which is greater than the value for the UK (6.2 tCO₂/capita), Japan (9.0 tCO₂/capita) and much greater than the average for Asia (3.6 tCO₂/capita) (Enerdata, 2014a). It can be observed from Figure 63 that there has been a shift in the sectors accounting for the largest percentage of emissions. In 1975, the refining and transport sectors accounted for half

of the total emissions and the generation of heat and electricity accounted for 40%. In 2013, the industrial sector accounted for a much larger proportion of emissions than in 1975 and the emissions from transport and refining were reduced. Generation of heat and electricity is still the largest overall contributor, accounting for 36% of the total emissions in 2013. Within electricity and heat production, the dominant fuel was traditionally oil. This has now shifted almost entirely to natural gas based production in 2013. Singapore has historically had a strong refining capacity and this is clearly seen in Figure 63 with refining being a large contributor to emissions in both years.

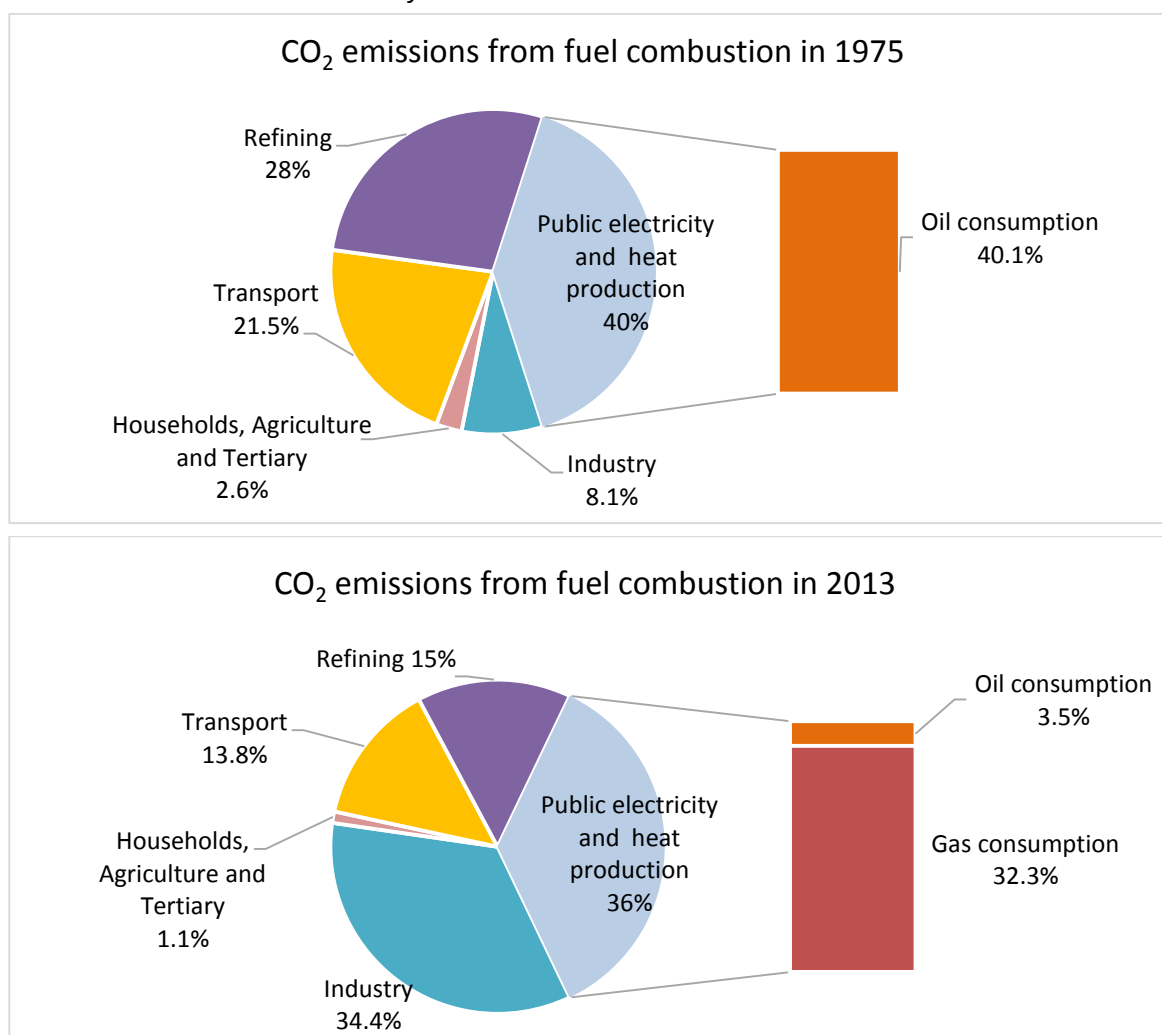


Figure 63: Comparison of CO₂ emissions by sector for Singapore in 1975 and 2013 (Enerdata, 2014a).

8.1.2 Climate Change Targets

Singapore ratified the Kyoto Protocol in 2006 and just prior to the 2009 Conference of Parties at Copenhagen, pledged to reduce emissions by 16% from the 2020 business as usual (BaU) level. However, this target was contingent on a legally binding global agreement being reached (Nachmany et al., 2015). An agreement was not achieved at Copenhagen but nevertheless, Singapore has embarked on a voluntary strategy to reduce emissions by 7-11% below the 2020 business as usual levels, mainly through energy efficiency measures (Enerdata, 2014b). The government has announced that they will strengthen this target to the

previously stated 16% reduction if an agreement is reached at the COP 21 in Paris in December 2015.

The National Climate Change Strategy was first released in 2008 and outlines Singapore's proposal to reduce CO₂ emissions across all sectors. Under the business as usual (BaU) scenario (without policy interventions) it was predicted that Singapore's emissions could reach 77.2 MtCO₂ by 2020. Figure 64 indicates the potential emissions reductions that the government envision from each sector in Singapore in order to achieve the 7-11% reduction goal. The power sector is seen as the sector that could offer the largest emissions savings, mainly through the switching of fuel from oil to natural gas, increasing the average efficiency of plants and the increased use of solar energy (NCCS, 2012).

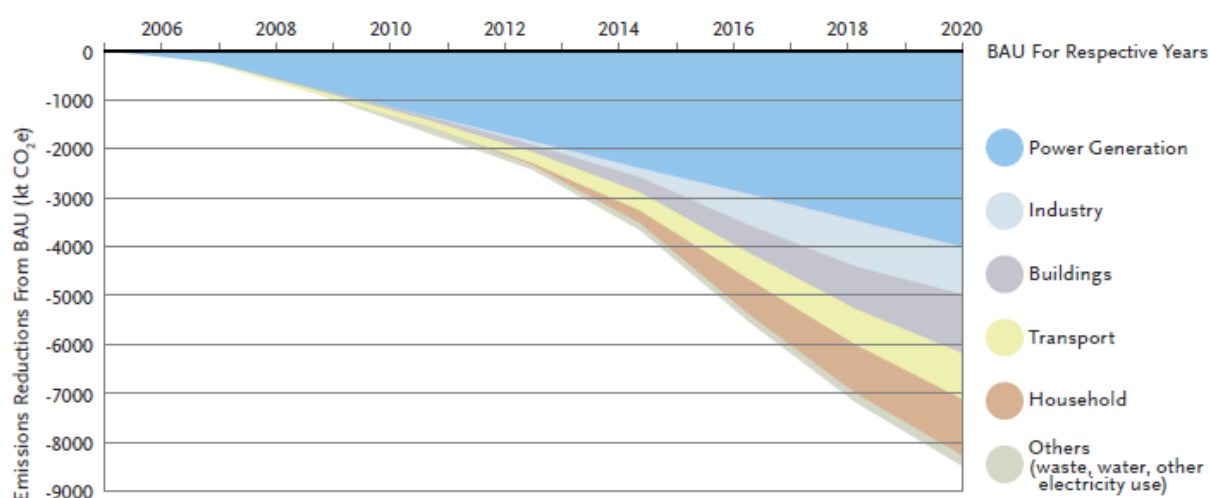


Figure 64: Potential emission reductions each sector in Singapore from BaU projections up to 2020 (NCCS, 2012).

Singapore recently submitted its INDC as required by the UNFCCC before the COP21 meeting in December 2015. Singapore have pledged to reduce their emission intensity by 36% from 2005 levels by 2030 with an aim to peak emissions by that year (LCS, 2015). Climate Action Tracker have assessed this target and deemed it 'inadequate' and is therefore 'not in line with any interpretations of a fair approach to hold warming below 2°C' (CAT, 2015). If other countries imitated this level of ambition, the global temperature increase would likely be 3-4°C. The assessment takes a range of different interpretations from the literature of what is a 'fair' approach to tackling climate change. Some of these approaches include taking the historic contributions of greenhouse gas emissions, assessing the economic capability of a country to reduce emissions and reaching equal cumulative per capita emissions (CAT, 2015).

Figure 65 indicates how the emission intensity (i.e. CO₂ emissions per unit of GDP) has decreased since 1990. It can be observed that emission intensity decreased rapidly until around 2008 when the rate of decrease started to slow. The emissions intensity in 2005 was 0.178 kgCO₂/US\$ (Enerdata, 2014a). To achieve a reduction of 36% to meet the INDC target, the emissions intensity would have to decrease to 0.114 kgCO₂/US\$ by 2030. The emission

intensity was extrapolated up to 2040 based on two different rates of decrease. Taking the average rate of decrease between the baseline year 2005 and 2014, gives a rate of decrease of 2.6% each year. However, if the average decrease is taken for just the years 2010-2014, the rate of decrease in emission intensity is lower at 1.4%. Therefore both of these potential rates of decrease were plotted as indicative scenarios up to 2040.

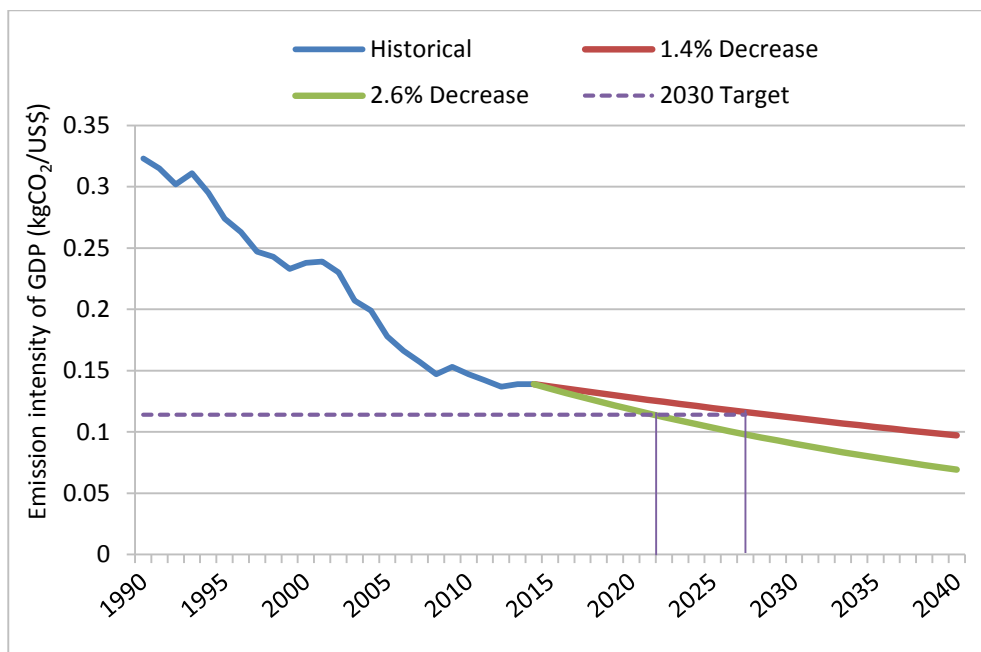


Figure 65: Historical emission intensity from 1990-2014 (Enerdata, 2014a). Two potential reduction pathways for future emission intensity are shown, along with the 2030 target.

It can be seen that if the 2.6% rate of decrease occurs, then the INDC target can be met by 2022. However, if the rate of declining emission intensity follows the most recent trend observed between 2010-2014, (i.e. 1.4% average decrease in intensity) then the target is still met by 2028. This indicates that Singapore's target is not as ambitious as it could be, as the target can be reached even with the lower level of effort. Given the decreasing trend of emission intensity over the past 25 years, perhaps Singapore could aspire to achieve a larger decrease in emission intensity by 2030, or determine a new target based on higher absolute emission reductions.

8.2 Singapore's Electricity System

8.2.1 Electricity Market

Electricity plays an important role within Singapore's economy as the supply of reliable and competitively priced electricity is integral for many energy intensive manufacturing industries and businesses that operate out of Singapore. Liberalisation of the electricity markets has been occurring since 1995 and generation companies now compete to sell their electricity to the National Electricity Market of Singapore that was established in 2003. The market share of these companies is outlined in Figure 66. Three companies dominate electricity generation in Singapore: Senoko Power Ltd, Power Seraya Ltd and Tuas Power Ltd (Enerdata, 2014b). These companies were owned by the state until being sold to private investors as a result of

the deregulation policies that were initiated in 2001 (EMA, 2010). In 2014, Pacific Light Power started operations at their new 800 MW CCGT plant on Jurong Island leading to the company taking an 8.3% share in the electricity market (see Figure 66). It is the first plant in Singapore to be fuelled entirely on imported LNG (PacificLight, 2015).

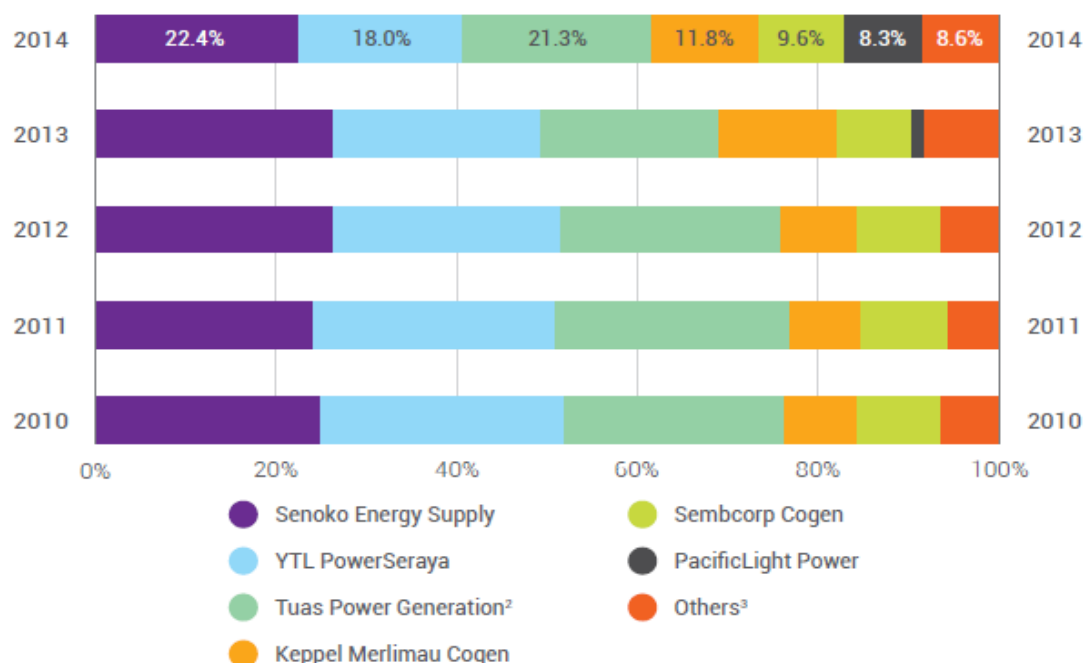


Figure 66: Outline of the percentage share of the six major players in Singapore's electricity market (EMA, 2015).

The transmission network is a monopoly, controlled by the Singapore Power Group (Enerdata, 2014b). The net distribution and transmission losses from the network are low at 1.7% of total distributed electricity in 2014 (Enerdata, 2014b). Singapore is known for having a very reliable electricity system. The System Average Interruption Duration Index (SAIDI) is the average duration of unplanned power outage per consumer. The System Average Interruption Frequency Index (SAIFI) is the average number of interruptions in power supply per consumer. Both the SAIDI and SAIFI values are very low for Singapore, indicating the stability of the network (EMA, 2011).

8.2.2 Resource Potential

Singapore does not have any domestic hydrocarbon reserves therefore imports all of its crude oil and natural gas (EIA, 2014d). In terms of renewable potential, Singapore has limited potential for hydroelectric, wind or tidal power. Wind speeds are around 2 m/s, which are too low for wind energy to be commercially viable, and land availability is a major constraint (MTI, 2007). Wave and tidal energy are not feasible due to the large amount of shipping activity surrounding Singapore's coastline (APEREC, 2013a). Waste-to-energy incinerators have been a part of Singapore's generation mix since the 1970s and there is potential for this to expand

along with developing biomass-fired plants. However, the lack of available land space in Singapore makes the potential for biomass as a feed stock fairly low (Reegle, 2013).

The renewable energy technology that has the most potential in Singapore is solar energy, due to the favourable climate with average solar insolation of 1635 kWh/m², which is very similar to Malaysia (Ismail et al., 2015). One of the main issues with developing solar energy in Singapore is the lack of available space for large installations such as the solar parks being developed in Malaysia. The Solar Energy Research Institute of Singapore (SERIS) produced a solar roadmap for Singapore and estimate that there is 27-45 km² of space available for PV installations. This equates to a maximum of 10 GW of solar PV cumulative installation. The estimate is based on rooftops, infrastructure and the potential for novel approaches such as floating PV installations in lagoons (Luther & Reindl, 2013).

8.2.3 Energy Trade

Due to its strategic geographical location along the shipping routes from the major oil producing countries in the Middle East to Southeast Asian importing countries, Singapore has established itself as a major hub for oil and petroleum trade although it has no domestic oil reserves (Enerdata, 2014b). Singapore has an oil refining capacity of 1.4 mb/day from three refineries, which is well above its domestic consumption. Singapore imports crude oil mainly from the Middle East and exports petroleum products to Malaysia, Australia and China.

Singapore has been importing gas via pipeline from Indonesia and Malaysia for the past 20 years. There have been a number of disruptions in supply over the years and in 2006 a large blackout across parts of Singapore was a result of a cut off in supply from the Malaysian pipeline. Subsequently, with increasing concerns over the security of supply, the government initiated a scheme to build an LNG terminal on Jurong Island, operated by Singapore LNG Corporation (SLNG) (SLNG, 2014). The government completed the creation of the artificial Jurong Island in 2009 just off the southern coast of Singapore in response to increasing land constraints on the mainland. Jurong Island has now become the focus for the countries' petrochemical industry as well as the site of the new LNG terminal.

This LNG regasification terminal was completed in 2013 and has a 6 Mt/year capacity with three 188,000 m³ storage tanks (Enerdata, 2014b). SLNG plan to expand the capacity to 9 Mt/year by 2018 (SLNG, 2014). In 2015, LNG accounted for 22% of gas imports (EMA, 2015). The government also plans to build a second regasification terminal to further decrease reliance on piped natural gas from Malaysia and Indonesia. The Jurong Island 2.0 Masterplan is a strategy to expand the current infrastructure on the island whilst creating an integrated system that optimises the efficient use of water, energy and raw materials. There has been an on-going project to build an underground oil storage facility in the Jurong rock caverns. The project was completed in 2014 and is South East Asia's first commercial underground storage facility that can store up to 9.2 mb of oil (Enerdata, 2014b).

Singapore imports a small amount of electricity from Malaysia through the 450 MW interconnector line that has been operational since 1985 (Enerdata, 2014b). As part of the ASEAN Power Grid project, Singapore could potentially be connected via new 600 MW interconnectors to Batam and Sumatra in Indonesia by 2017 and 2020 respectively. There are also plans for a new interconnection from Peninsular Malaysia with construction starting in 2018 (Ibrahim, 2014b).

8.3 Energy Policy and Drivers

8.3.1 Structure of the Energy Administration

The Ministry of Trade and Industry has an Energy Division which delivers the policy and strategic goals for Singapore's energy sector. The regulator for both the electricity and gas sectors is the Energy Market Authority (EMA) (Enerdata, 2014b). The Energy Policy Group (EPG) was formed in 2006 as an inter-departmental agency, led by the Ministry of Trade and Industry. The EPG has representatives from the Ministries of Finance, Foreign Affairs, Environment and Water Resources as well as from the EMA and National Environmental Agency (Nachmany et al., 2015).

8.3.2 Energy Policies

Singapore has no domestic energy resources, resulting in their high dependence on imports and subsequent vulnerability to global price fluctuations as well as potential geopolitical tensions. Energy policy in Singapore has been focused on securing a reliable and affordable supply of energy for their small country as well as diversifying their energy sources (MTI, 2007). The electricity industry in Singapore was traditionally government owned and vertically integrated. In 1995, the government commenced a strategy to liberalise and deregulate the energy sector in order to reduce the amount spent on subsidies in this sector and also supply electricity at competitive prices (EMA, 2010). The electricity and gas markets were privatised and consequently the EMA was set up in 2001 as a regulator. The National Electricity Market of Singapore was operational by 2003 as a pooled electricity trading system. By 2008, the government had completely divested from the three main power generating companies in Singapore (EMA, 2010).

The National Energy Policy Report (NEPR) was released by the EPG in 2007 as a "holistic national energy policy framework to meet [Singapore's] objectives of economic competitiveness, energy security and environmental sustainability" (MTI, 2007). Although the NEPR acknowledged the need for international solutions to tackle climate change, in the NEPR the government have stated that 'the ultimate aim of our energy policy is to sustain Singapore's continued economic growth' (MTI, 2007). There are six strategies that are focused around this central objective of continuing economic growth including: (i) promotion of competitive markets, (ii) diversification of energy supplies, (iii) improving energy efficiency, (iv) investment into energy R&D, (v) stepping up international cooperation and (vi) developing a whole-of-government approach to energy policy.

Energy Efficiency

Initiatives to improve energy efficiency within Singapore have been an integral part of recent energy policy. Energy efficiency measures are the key strategy employed by the government in order to reduce emissions after 2020 (NCCS, 2012). The Energy Efficiency Programme Office (E²PO) was set up in 2007 to promote energy efficiency initiatives within the country. In 2012, The Energy Conservation Act was released which sets energy efficiency standards for large industrial energy users and mandates them to appoint an energy manager. The energy manager's role is to submit a compulsory annual energy efficiency improvement plan (Enerdata, 2014b). The Energy Conservation Act also introduced mandatory energy efficiency labelling for air-conditioners, refrigerators and many other household appliances (NEA, 2015).

Research and Development

The government places high importance on supporting innovative energy solutions and therefore has set up many R&D institutions. The NEPR outlines some of the R&D activities occurring within the clean energy sector. The National Research Foundation (NRF) has set a budget of US\$ 140 million for research into clean energy technologies. The NRF also launched the US\$ 300 million National Innovation Challenge on Energy Resilience for Sustainable Growth to develop cost effective energy solutions that can be deployed within 20 years (MEWR, 2015). The EMA has also pledged to establish a US\$ 25 million Energy Storage Programme that will support the development of large scale, energy storage systems for the power sector (MTI, 2007).

The Solar Energy Research Institute of Singapore (SERIS) was set up in 2008 to develop the solar market in Singapore and provide a focal point for R&D activity (Enerdata, 2014b). Research areas include novel PV concepts such as organic solar cells as well as the integration of solar technology into energy efficient buildings using intelligent control systems (SERIS, 2015). The Solar Nova program, led by the Economic Development Board (EDB) also aims to build industry capacity in this sector (MEWR, 2015). The Solar Capability Building Programme was set up in 2009 under the Housing Development Board to develop solar technology for use in public buildings and housing. There is also on-going research involving the potential for floating solar PV projects in Singapore's reservoirs and lagoons. The EDB and the national water agency announced a 2 MW pilot project at the Tengeh Reservoir that will cost around US\$ 7.7 million (NCCS, 2011).

Climate Change and Sustainability

For many years, Singapore has placed environmental issues high on the agenda, particularly air and water quality. The country ranked 4th in the world in the Environmental Performance Index in 2014 based on a range of environmental indicators (EPI, 2014). Air pollution has been regulated under the Clean Air Act of 1971 and Singapore has an extensive network of both air and water quality sensors that monitor pollution levels (MEWR, 2015).

The National Climate Change Secretariat was formed in 2010 as a coordinating body for climate change action plans and policies and updated the country's strategy on climate change in 2012 (Nachmany et al., 2015). The clean energy sector was identified as a key area for both emission reductions but also economic growth. As part of the restructuring and liberalisation of the energy sector, attracting international investment into Singapore has been a main target for the government. Several initiatives have been put in place to attract international companies to develop green industries in Singapore in order to create jobs and encourage R&D activities in the clean energy sector (NCCS, 2012).

The Sustainable Singapore Blueprint was first published in 2000 with the latest updated version released in 2015. It outlines the government's vision for all aspects of creating a more sustainable and green economy. A target was announced aiming to reduce energy intensity by 35% by 2030 compared to a baseline of the 2005 level (Nachmany et al., 2015). All the policies discussed in this section are summarised in Table 24.

Table 24: Summary of important energy policies in Singapore.

Date	Policy	Details
2001	Electricity Act	Restructuring of the energy sector through the creation of a competitive market framework for electricity
	Gas Act	Creation of a competitive market framework for the gas industry
2007	National Energy Policy Report	Comprehensive energy policy and strategy for Singapore
2008	National Climate Change Strategy	Overview of Singapore's approach to dealing with climate change
2009	Sustainable Development Blueprint	Outlines targets for air quality, resource management, energy efficiency and other sustainable development issues. Updated regularly (most recent version in 2015)
2012	Energy Conservation Act	Mandates energy efficiency and energy management standards for large consumers. Introduced mandatory energy labelling for appliances

8.4 Current Generation Capacity

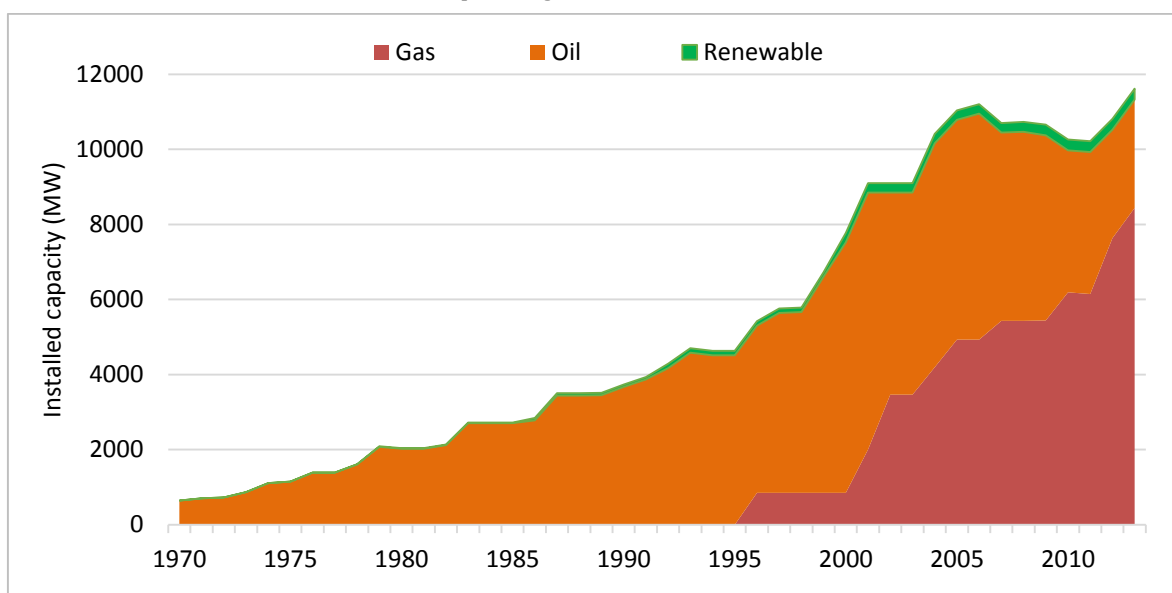


Figure 67: Historical changes in the installed capacity for Singapore (1970-2013). Renewable includes waste-to-energy plants and solar (Enerdata, 2014a).

Total installed capacity was 12,889 MW as of April 2015 (EMA, 2015). Historical electricity generation was dominated by oil until the mid-1990's when the government started to pursue natural gas for electricity generation. The impact of these policies can be clearly seen in Figure 67 with the introduction of natural gas into the electricity mix in 1995. Figure 67 indicates the lack of diversity within Singapore's electricity mix over the past 40 years with only a small percentage of renewable capacity coming online in recent years. Singapore's power generating capacity now almost entirely consists of gas fired CCGT plants with a small amount of waste-to-energy generation (289 MW) and solar PV (33 MW) connected to the grid.

It can be observed in Figure 68 that just over 90% of electricity generation is based on natural gas, although there were still some incumbent oil-fired power stations within the electricity capacity in 2013. Senoko Energy have recently completed the conversion of three oil-fired power turbines into two high efficiency CCGT plants with a combined capacity of 862 MW (Senoko, 2013). The competitive market in Singapore is encouraging the shift to CCGT plants due to the increased efficiency of these plants and consequent cost savings that are gained as a result. The switch from oil fired power stations to higher efficiency gas fired combined cycle gas turbines (CCGTs) has meant that the average efficiency of power generation has increased from 34% in 2000 to 46% in 2013 (Enerdata, 2014a).

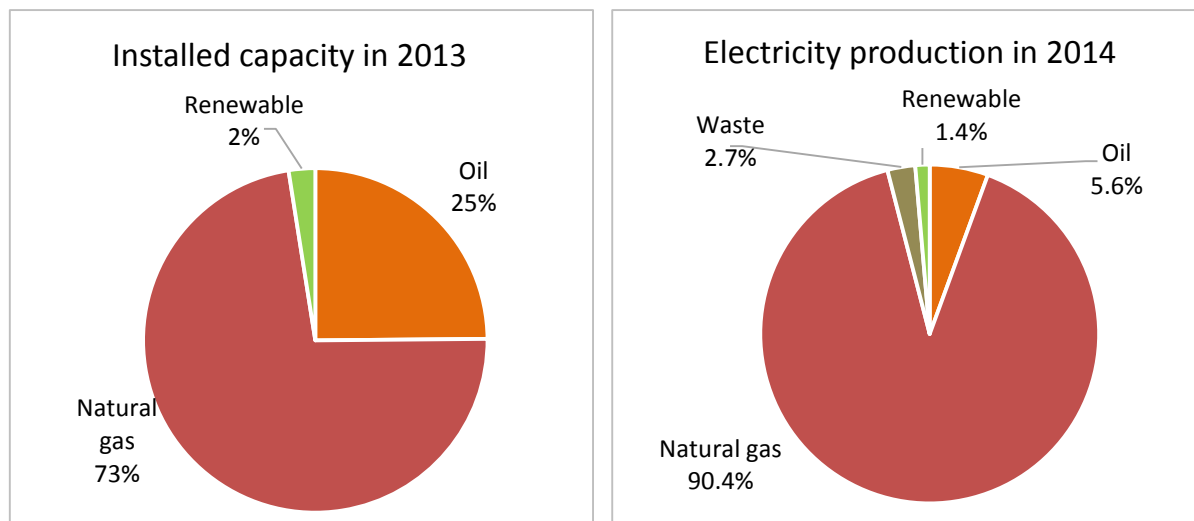


Figure 68: Comparison of installed capacity and electricity production in Singapore for 2013 (Enerdata, 2014a).

Figure 68 indicates that only a small percentage of electricity production is from renewable sources. It can be seen that 2.7% of generation came from waste, which is mostly from municipal waste-to-energy plants as previously discussed. There are currently four waste-to-energy power plants in Singapore operated by Kepple Seghers Tuas, Senoko and the National Environment Agency (EMA, 2015). The National Environment Agency estimated that in 2014, 60% of waste was recycled, 38% was incinerated in these waste-to-energy plants and only 2% was disposed of in landfill (ZeroWaste, 2015). It can be observed from Figure 68 that 1.4% of electricity generated from renewable sources which consists of solar PV installations and renewable biomass.

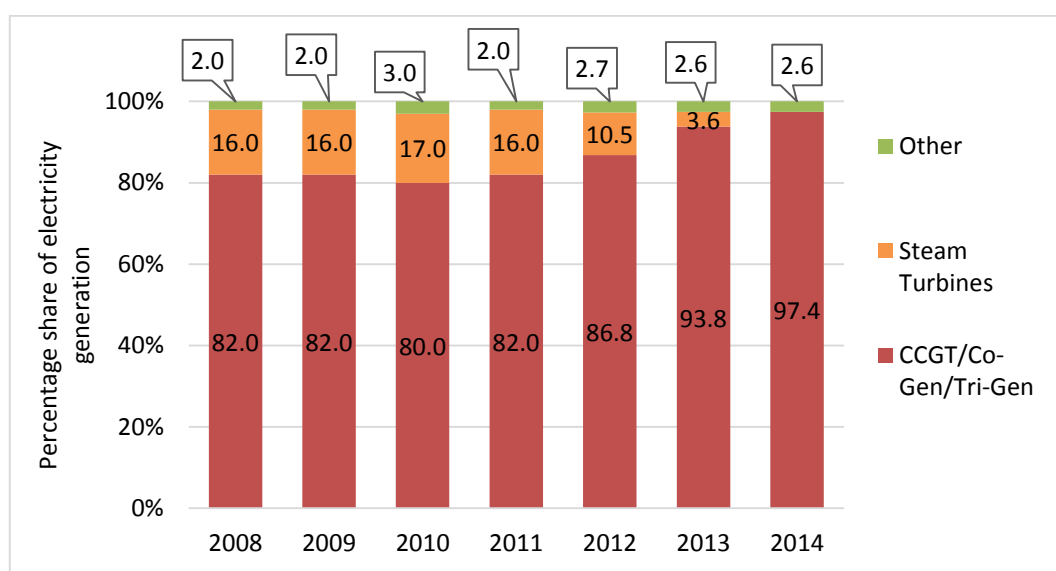


Figure 69: Changes in electricity generation plant type in Singapore from 2008-2014. 'Other' includes electricity generation by Wholesale Licenses, Solar PV installations and Waste-To-Energy Plants (EMA, 2015).

The EMA has the latest statistics concerning electricity generation in Singapore and Figure 69 indicates the recent increasing share of gas-fired power stations in Singapore's generation mix, which includes the expansion of many power plants. Keppel Corporation recently increased the capacity of its co-generation plant from 500 MW to 1300 MW (Keppel, 2010). In 2014, electricity generated from gas fired stations (CCGT, co-generation and tri-generation plants) made up 97.4% of the total. The remaining share (2.6%) consisted of waste to energy plants, wholesale licenses and solar energy. In 2014 there were 636 grid connected solar PV installations totalling 33 MW capacity (EMA, 2015).

8.5 Discussion and Analysis

8.5.1 Government Projected Capacity and Electricity Generation

The government expect that electricity demand will grow by 2-4% annually over the next 10 years and Figure 70 illustrates the range in forecasted estimates. Electricity generation in 2013 was 47.9 TWh (Enerdata, 2014a) which is consistent with these 2011 projections.

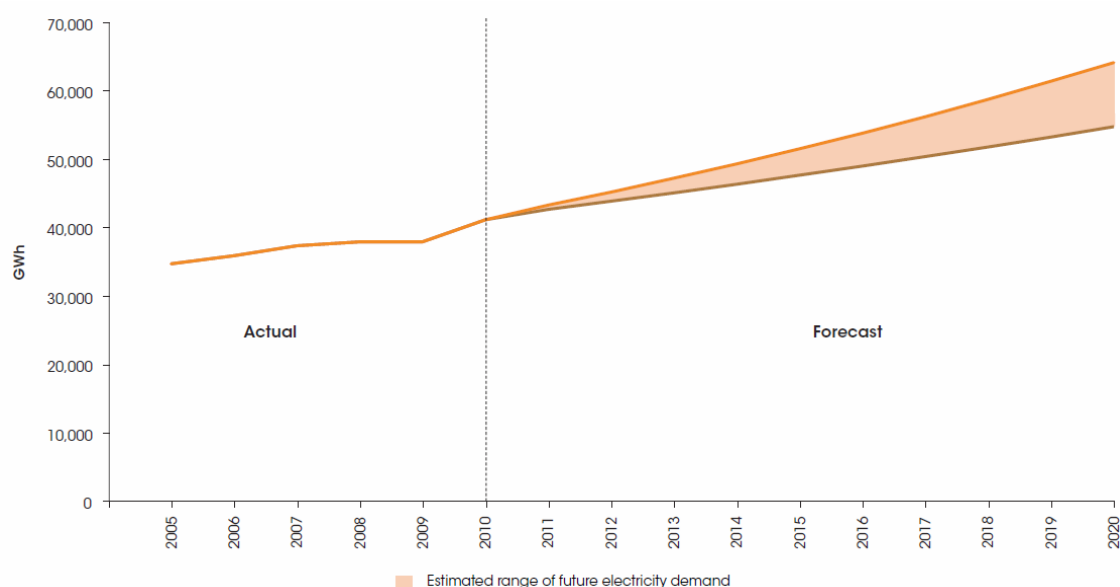


Figure 70: Singapore's projected increase in electricity demand up to 2020 (EMA, 2011).

Power generation companies in Singapore have expanded the electricity capacity considerably in recent years. The capacity has almost doubled from 7773 MW in 2000 to 12,888 MW in 2015. Despite this rapid increase in capacity, peak demand was only 6,771 MW in 2015 (EMA, 2015). This leads to a very high reserve margin and a reliable system that the power system operator is well respected for (EMA, 2015). There is therefore not a pressing need for Singapore to dramatically increase the generation capacity in the near future as there is more than enough capacity to deal with annual demand increases. In 2010, the Government undertook a pre-feasibility study on the potential for nuclear energy to add to the generation mix and concluded that nuclear energy was not suitable for deployment in Singapore for the foreseeable future (MTI, 2012).

As part of the Economic Development Board's ongoing plans to enhance the petrochemical industry on Jurong Island, Tuas Power have commissioned the Tembusu Multi-Utilities Complex, which will feature a desalinisation plant and waste water treatment facility powered by a 160 MW Biomass Clean Coal cogeneration plant (FRS, 2013). The coal power will feature highly efficient Circulating Fluidised Bed boilers that reduce emissions by up to 80% and any excess electricity generated will be sold to the electricity market (TNP, 2014). By introducing coal into the electricity system, the EDB is indicating its desire to further diversify the source of fuel for power generation and enhance energy security.

The four waste-to-energy plants in Singapore incinerate 7740 tonnes of waste per day (MEWR, 2015). Sembcorp are currently constructing a new waste-to-energy plant that will utilise industrial and commercial waste to produce 140 tonnes of steam per day for companies on Jurong Island by 2016 (Sembcorp, 2014). The new plant will incinerate an additional 1000 tonnes per day.

The EMA projected the installed capacity in its 2011 'Statement of Opportunities'. Figure 71 indicates the projected increase in peak demand and total generation capacity. As much of the new generation capacity was planned for the south western region of Singapore (i.e. to provide more power to Jurong Island), there were some concerns that the transmission system would not be sufficient in this area. The EMA therefore projected future installed capacity up to 2020 under two scenarios, one taking into account this transmission constraint and one without. It can be observed that under both scenarios, the installed capacity remains well above the projected peak demand up to 2030. Since installed capacity reached 12,888 MW in 2015, it can be assumed that most of the planned generation capacity in 2011 has been commissioned.

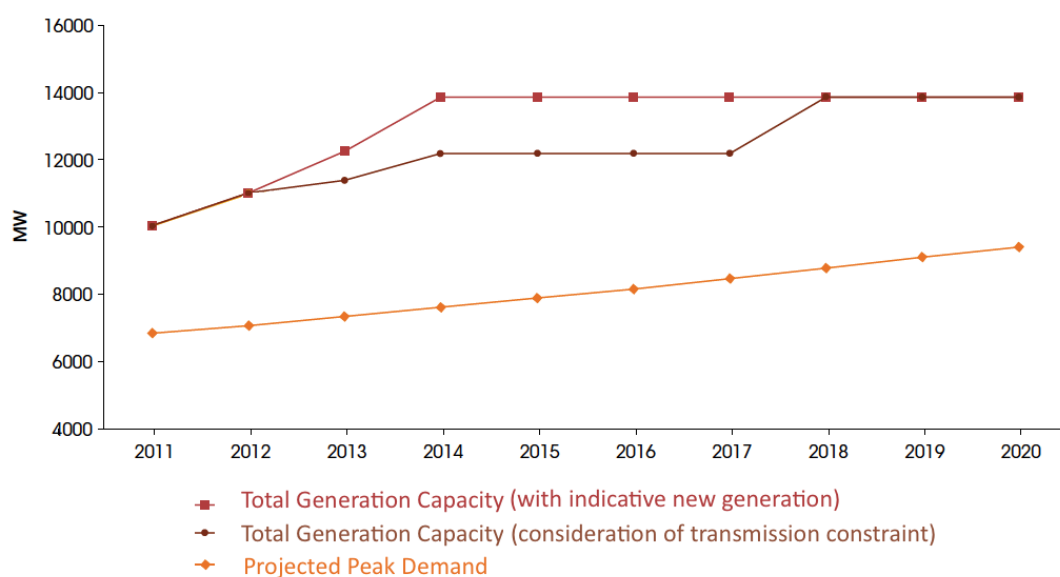


Figure 71: Projected increases in peak demand and total generation capacity under two scenarios. Adapted from (EMA, 2011).

Sembcorp's new waste-to-energy plant and the Tembusu Multi-Utilities Complex 160 MW cogeneration plant will further increase the installed capacity over the next three years. With the strong emphasis on energy efficiency targets, the amount of energy used by intensive sectors such as the petrochemical and manufacturing industries should decline over the coming years. This may lead to peak demand increasing at a slower rate than the EMA have predicted.

8.5.2 Renewable Energy Targets

The Sustainable Singapore Blueprint outlined a target to increase the installed capacity of solar energy to 350 MW by 2020. Increasing the solar energy capacity will involve a rapid acceleration in deployment, as there was only 33.1 MW of capacity installed as of 2014. Under the Solar Roadmap for Singapore, SERIS developed several scenarios to investigate the potential amount of electricity that could be generated from solar energy, based on the land area available for PV installations. The baseline scenario (BAS) takes into account an area of 27 km² for PV installation whilst the accelerated scenario (ACC) uses the maximum 45 km² of space for PV installation (Luther & Reindl, 2013).

Table 25 outlines the details of the two scenarios including the potential CO₂ savings that could arise from the installation of solar PV technology in Singapore up to 2050.

Table 25: The potential for installed capacity and electricity generation from solar energy under the Baseline (BAS) and Accelerated (ACC) scenarios developed by SERIS up to 2050 (Luther & Reindl, 2013).

	Scenario	2012	2020	2030	2050
Cumulative installed capacity (MW)	BAS	10	650	3000	5000
	ACC	10	900	4000	10000
Annual electricity generation (GWh)	BAS	10	800	4000	7000
	ACC	10	1200	6000	15000
Potential Annual CO₂ reductions (Mt)	BAS	0.007	0.4	2	3.5
	ACC	0.007	0.6	3	7.5

Under the baseline scenario, the 350 MW target outlined by the Sustainable Singapore Blueprint could be potentially achieved before 2020. The accelerated solar deployment scenario seems overly optimistic. If the projected electricity demand in 2020 is expected to be approximately 60 TWh (Figure 70) then solar energy is projected to contribute to 25% of annual demand. Under the BAS scenario, solar would contribute 11% to annual demand which is a much more realistic figure but would still require a huge acceleration in deployment.

Adding a significant amount of solar capacity will lead to necessary infrastructure improvements to effectively connect the intermittent power to the grid. The EMA has set up a number of programmes to assess the potential for smart grid applications in Singapore such as the Intelligent Energy System, which involves the deployment of smart metres. Energy storage is another technology that is gaining importance in Singapore's R&D landscape.

Innovative technologies such as these will enhance the resilience and flexibility of the electricity network especially when integrating intermittent solar energy into the system.

8.5.3 APERC Projections

APERC have two main scenarios: the Business as Usual (BaU) scenario and the High Gas (HGS). Although Singapore does not produce any natural gas domestically, the country has been pursuing gas for electricity since the mid-1990s and are currently planning to expand the new LNG regasification terminal to diversity supplies. Therefore, it can be assumed that Singapore will continue to maintain a high percentage of gas fired capacity within its electricity system, making the HGS scenario particularly relevant for Singapore.

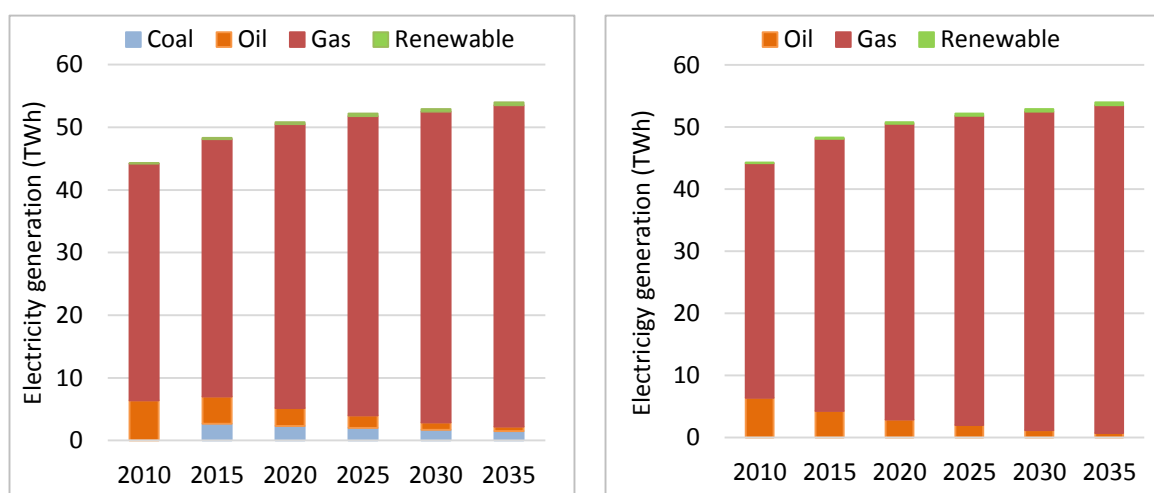


Figure 72: Projected electricity generation under APERC's BaU scenario (left hand figure) and High Gas scenario (right hand figure) (APERC, 2013a).

Figure 72 depicts the projected increases in Singapore's electricity generation under the different scenarios. Both APERC scenarios are very similar in terms of overall generation. However, it can be observed that coal enters the generation mix under the BaU scenario in 2015. This could be the result of the 160 MW coal co-generation plant at the Tembusu Multi-Utilities Complex. However, the BaU scenario predicts that 1000 MW of coal capacity will enter the mix which is much higher than the capacity of the new coal co-generation plant. The Energy Market Authority have not ruled out new coal plants for Singapore as way of diversifying the electricity system:

"In the medium term, EMA is prepared to allow the entry of new energy options on a market basis. Further diversification of our fuel mix will encourage healthy competition in our electricity market and benefit households and industry consumers." (EMA, 2011)

It is unclear whether the government will allow new coal plants as they have strongly emphasised the importance of switching to gas-fired plants, a move that has been contributing

to the countries declining energy intensity. The National Environment Agency also have a number of stringent emission regulations in place that any new coal plants built would have to comply with, increasing the cost of construction.

APERC predict that final electricity demand will increase to 51 TWh by 2035. This is a slightly more conservative estimate than the EMA estimates seen in Figure 70. As the model used historical data up to 2009 to project the future capacity, the results are slightly skewed. As has previously been discussed, Singapore's generation mix is now almost entirely natural gas based so it is very unlikely that any oil capacity will remain up to 2035. The government's plans to expand the LNG capacity of the country further supports this hypothesis.

The percentage of electricity generated from renewable energy does not change between the scenarios and does not increase significantly up to 2035. This is due to the fact that the APERC projections are now out of date and have not been updated to reflect the government's plans to increase the solar capacity up to 2020.

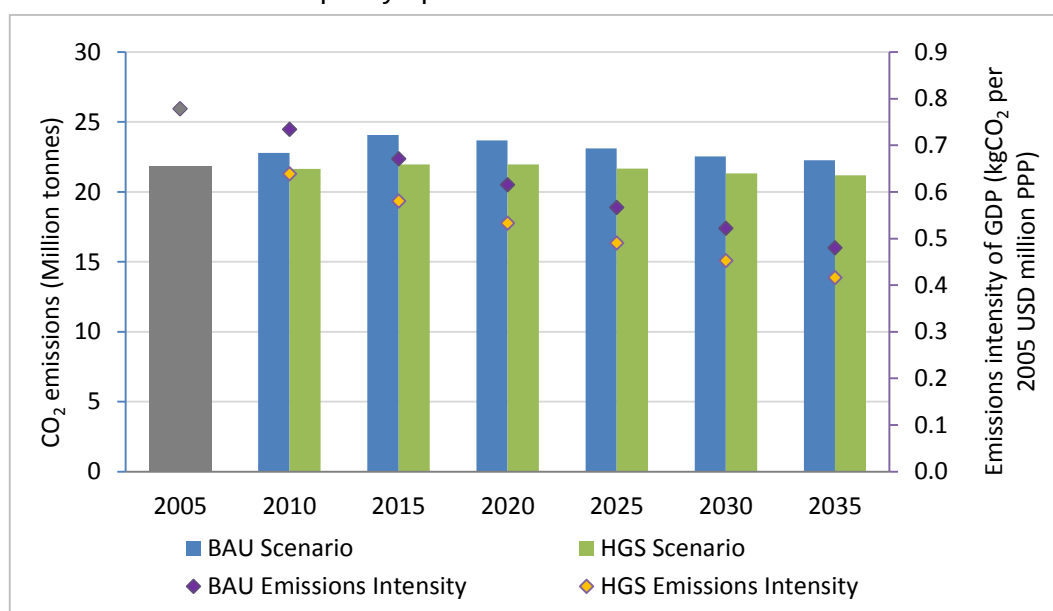


Figure 73: Total CO₂ emissions from electricity generation and overall emission intensity for Singapore up to 2035 under BaU and HGS scenarios (APERC, 2013b).

The APERC projections of CO₂ emissions from electricity generation do not differ greatly for the BaU or HGS scenario as seen in Figure 73. CO₂ emissions from electricity generation under the BaU scenario are slightly higher due to the presence of coal in the generation mix, which accounts for the slightly higher emissions intensity also. The emissions intensity of GDP is expected to decline under both scenarios up to 2035 based on the implementation of energy efficiency measures that Singapore have been pursuing aggressively. Under the BaU scenario, the emission intensity decreased by 32% from the 2005 level by 2030 which does not meet the target outlined in Singapore's INDC. The higher emission intensity could be due mostly to the introduction of 1000 MW of coal into the generation capacity. In the HGS

scenario, the target is reached by 2025, mainly as a result of having no coal entering the generation mix.

As has been outlined throughout this section, there are limited plans to expand Singapore's generation mix due to the current overcapacity in the system. There are a lack of projection studies for Singapore's generation capacity due to this absence of capacity expansion meaning that only APERC's BaU is depicted in Figure 74. APERC's High Gas scenario is not included as the percentage of thermal capacity was very similar to the BaU scenario. The coal capacity that was predicted to enter the capacity mix is projected to displace some gas capacity in the BaU scenario where the availability of natural gas could be uncertain.

It can be observed that the generation mix is predicted to be highly dependent on thermal capacity and this is expected to continue up to 2035. With limited targets for solar capacity and the government focusing on improving energy efficiency as their main action towards climate change mitigation, it seems likely that Singapore's capacity mix will be dominated by natural gas towards 2035.

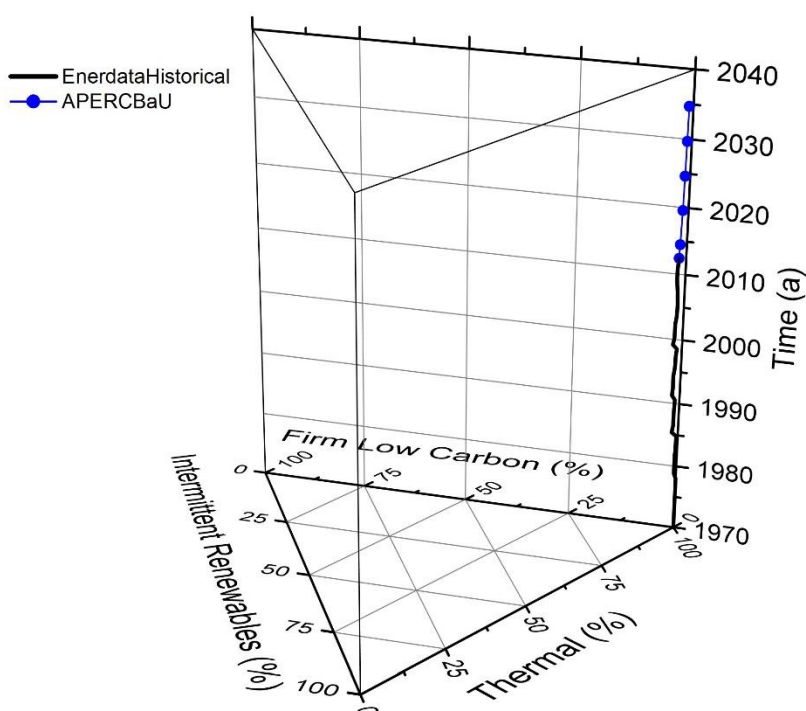


Figure 74: Singapore's projected capacity scenarios based on APERC's BaU scenario (APERC, 2013b).

8.6 Summary

Given Singapore's lack of domestic resources, the country is now in an important position to pursue clean energy and innovative research to improve their energy situation. There is much R&D effort underway in areas of clean energy but large-scale deployment has yet to materialise. Solar PV installations reached 33 MW in 2015, which is less than 10% of the 2020 government target of 350 MW. Having shifted electricity generation away from carbon intensive oil capacity to high efficiency gas-based generation, the carbon intensity of electricity production has decreased significantly over the past three decades. However, fuel switching to natural gas has reached its full potential for reducing emission intensity so Singapore should now be focusing its efforts on increasing renewable capacity in the electricity system.

Diversification of energy sources remains very important as the electricity system is almost entirely based on natural gas. The expansion of LNG infrastructure and the introduction of coal generation in the new Tembusu Multi-Utilities Complex are indicators that the government is pursuing alternative sources of fuel for electricity generation. Singapore will continue to maintain its position as an international hub for oil and petroleum trade into the foreseeable future. The refining and industrial sectors in Singapore are large contributors to overall emissions, accounting for just under 50% in 2014. These sectors must be taken into consideration when understanding Singapore's emissions portfolio towards 2030. Developing an integrated approach to reducing emissions across sectors of the economy is essential.

Singapore has overcapacity in its electricity system leading to a high reserve margin. With energy efficiency measures reducing power consumption from domestic and commercial consumers, this overcapacity is set to continue into the near future. The potential electricity interconnectors with Malaysia and Indonesia will further enhance connectivity and energy security within Singapore although there is no clear progress being made with these projects under the ASEAN Power Grid Programme.

Despite having strong policies in place to tackle other environmental issues such as air pollution, climate change targets are not deemed ambitious enough, based on Singapore's economic and technical capabilities. The emissions intensity target outlined in Singapore's INDC can be met through current energy efficiency policy measures, with minimal additional effort. Increasing competition between generation companies is likely to enhance energy efficiency measures in the long term. Singapore has the economic capability to be much more ambitious in its renewable energy targets as well as promote more innovative energy solutions such as large-scale electricity storage.

9 SOUTH AFRICA

Highlights

- South Africa has been facing an electricity shortage since 2008. This is due to unplanned maintenance outages at Eskom's ageing power fleet and years of underinvestment in generation capacity. These outages have a significant effect on economic development, with analysts at the CIA estimating that the country is unable to exceed a 3% growth rate unless these constraints can be resolved. Addressing this electricity shortage is the main driver shaping South Africa's domestic energy policy.
- The Integrated Resource Plan (IRP) 2010-2030 outlines capacity targets towards 2030. It calls for the addition of 55 GW of capacity by 2030, with the largest increase in capacity from renewable energy sources (18.9 GW).
- Coal is likely to continue supplying the majority of South Africa's generation. This is because the country has limited hydropower capacity, it has limited natural gas reserves, and its nuclear target faces uncertainty as the Department of Energy estimates that no new nuclear baseload capacity is required until after 2025.
- South Africa wants to increase private sector investment in the power sector. The Renewable Independent Power Producer Procurement Programme was implemented in 2011. In 2015, it had procured 5.2 GW of electricity capacity from renewable energy sources. It has also caused the price of renewable energy to decrease, and resulted in fuel savings as the country switched from diesel-fired generation to renewable energy to satisfy some of its peak demand.

9.1 Background

South Africa is a constitutional democracy composed of nine provinces (CIA, 2015d). South Africa's administrative capital lies in Pretoria, while its legislative capital is in Cape Town, and the judicial capital in Bloemfontein. The majority of South Africa's population lives in the coastal provinces, as well as the north-eastern province of Guateng (StatsSA, 2015). In 2014, South Africa's population was 54 million, with an urbanisation level of 64% (WB, 2015a).

The end of apartheid in 1994 ushered in a decade of economic growth, and South Africa is currently the second largest economy in Africa after Nigeria in terms of GDP (EIA, 2015b). With a GDP of US\$ 349.8 billion in 2014, South Africa is classified as an upper-middle income country by the World Bank (WB, 2015c). Real GDP growth is expected to slow towards 2015, however, with the government indicating that the economy is in a 'low growth, middle income trap' (NPC, 2011). This is due to the effect apartheid policies had on the nation, which led to economic exclusion, income inequalities, and high levels of poverty (NPC, 2011). Labour strikes and electricity supply shortages further hinder economic growth (WB, 2015c). The National Development Plan indicates that eliminating income poverty (currently at 39%) and reducing inequality are the government's two main priorities towards 2030 (NPC, 2011).

South Africa has a relatively large service sector, which accounted for 68.4% of GDP in 2013, while the industry and manufacturing sector contributed 29% (CIA, 2015e). The sectors of the economy are interlinked, however, with the service sector of the economy reliant on growth in South Africa's energy sectors, particularly the coal mining industry (EIA, 2015b). The mining,

manufacturing and industry sectors of the economy attract foreign direct investment and account for approximately 60% of its export earnings (IDDRI & SDSN, 2014). South Africa's resource-intensive manufacturing industries thus remain a significant driver of economic growth. As a result, South Africa is the largest energy consumer in Africa, accounting for 30% of the continent's total energy consumption (BP, 2015). While final energy consumption increased 3% on average annually between 2000 and 2007, it has remained stable since 2007 (Enerdata, 2015h). Industry is the largest consumer of final energy, accounting for 36% in 2013. This is followed by the residential-tertiary sector (34%) and the transport sector (24%) (Enerdata, 2015h).

9.1.1 Emissions

South Africa's total GHG emissions were an estimated 543 MtCO₂ in 2010 (IDDRI & SDSN, 2014). Energy-related industries accounted for 78% of total GHG emissions. Processes, waste, and fugitive emissions accounted for 18%, while LULUCF accounted for 3.5% (IDDRI & SDSN, 2014). In 2013, South Africa's CO₂ emissions from the consumption of energy were an estimated 378 MtCO₂, making it the 16th largest emitter globally (Enerdata, 2014a). Although it houses less than 5% of Africa's population, South Africa accounts for 40% of the continent's total (World Bank, 2015a; EIA, 2015b). South Africa's per capita CO₂ emission rate of 9.3 Mt per capita in 2011 is above the global average of 5 Mt per capita, and the Sub-Saharan African average of 0.8 Mt per capita (World Bank, 2015a). South Africa's emission rate and relatively high CO₂ emissions per capita is due to the economy's reliance on energy-intensive industry. As shown in Figure 75, South Africa's CO₂ emissions have risen alongside GDP growth from 2001 until 2009. The economic recession in 2009 caused emissions to drop.

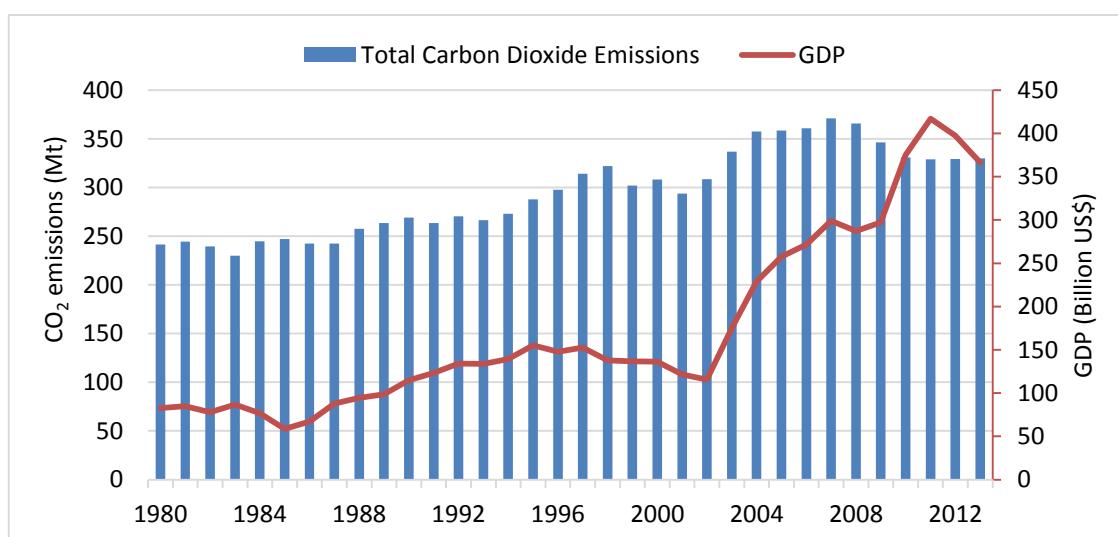


Figure 75: South Africa's GDP (World Bank, 2015a) and CO₂ emissions (EDGAR, 2015), 1980-2013.

As Figure 76 depicts, the electricity sector is the largest emitter of energy-related CO₂ emissions in South Africa, accounting for 52.5% in 2010 (IDDRI & SDSN, 2014). This is due to the dominance of coal in power generation. South Africa's emissions from the heat and

power sector have risen from 174 MtCO₂ in 2000 to 215 MtCO₂ in 2013 (Enerdata, 2014a). Industry is the largest consumer of electricity, accounting for 60% of electricity consumption in 2010. This is followed by the residential sector (20%) and buildings (15%) (IDDRI & SDSN, 2014).

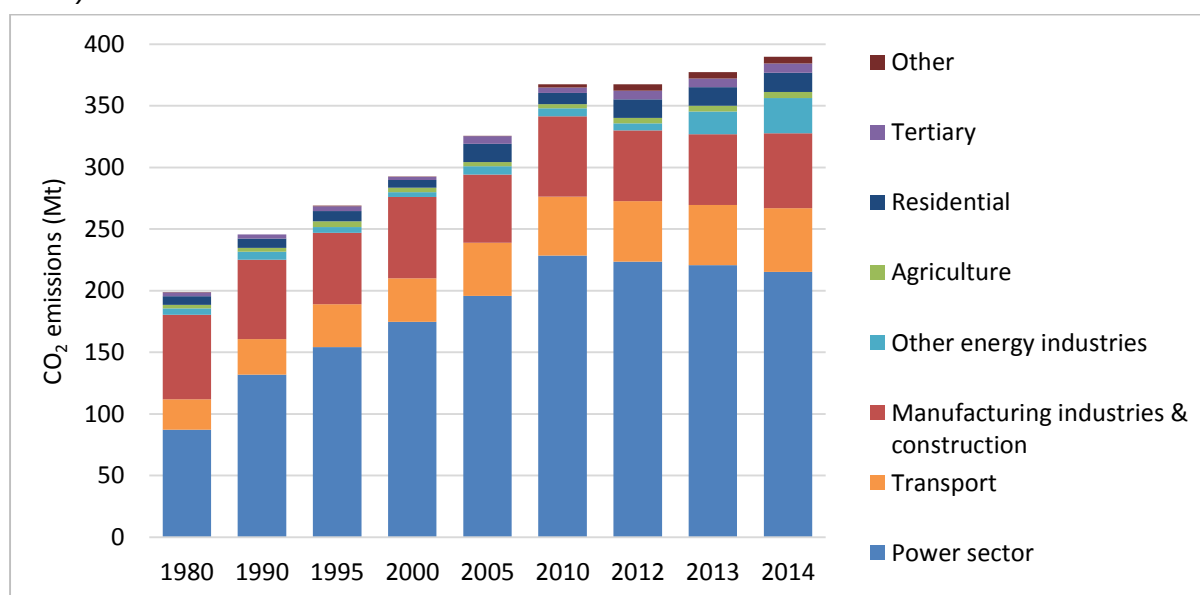


Figure 76: South Africa CO₂ emissions by sector, 1980-2014 (Enerdata, 2014a).

9.1.2 Climate Change Targets

South Africa ratified the Kyoto Protocol in 2002. As a non-Annex 1 country it is not obliged to meet quantify legally binding targets to reduce greenhouse gas emissions (Enerdata, 2015h). The nation's climate change pledges under Kyoto are therefore voluntary. The South African Department of Environmental Affairs and Tourism developed the Long Term Mitigation Scenarios (LTMS) study in 2007 to examine the nation's climate change mitigation potential towards 2050. These scenarios provide the foundation for South Africa's climate change policies (DEA, 2011). The business-as-usual scenario developed in the study is widely assumed to be the trajectory against which South Africa benchmarks its climate change pledges.

South Africa's INDC commitment reiterated its Copenhagen pledge to cut emissions 34% by 2020 and 42% by 2025 below the BaU, known as the 'Growth Without Constraints' trajectory (DEA, 2011). Furthermore, the emission levels are pledged to follow a 'peak, plateau, and decline' (PPD) trajectory. Emissions should peak between 2020 and 2025, plateau until 2035, and then decline towards 2050 (DEA, 2011). The government has repeatedly emphasised the need for climate change mitigation to be 'fair' and based on the principles of 'common but differentiated responsibility' (Marquard, Trollip & Winkler, 2011). South Africa's commitment is thus contingent on the condition that the nation receives 'financial, technology, and capacity-building support' (DEA, 2011).

9.2 South Africa's Electricity System

9.2.1 Electricity Market

The electricity planning system is managed by the Department of Energy, which mandates the amount of power generation that is necessary, and from which sources capacity must be generated (Eberhard, Kolker & Leigland, 2014). These mandates are set out in an Integrated Resource Plan (IRP), with the most recent IRP covering 2010-30. These plans are regularly updated to reflect electricity market developments, with the latest IRP updated in 2013. The National Energy Regulator of South Africa (NESRA) then licenses new capacity within the targets set in the IRP (Eberhard, Kolker & Leigland, 2014).

A state-owned company called Eskom operates the national grid. Eskom also supplies approximately 95% of South Africa's electricity (EIA, 2015b). Imports and generation from independent power producers (IPPs) supply the remaining 5% of electricity. South Africa's electricity consumption has remained around 208 TWh since 2007 (Enerdata, 2015h). South Africa is part of the Southern African Power Pool (SAPP), which also includes Namibia, Lesotho, Swaziland, Zimbabwe, Zambia, Botswana, Mozambique and DR Congo. South Africa is the largest player in SAPP, accounting for approximately 80% of installed capacity in the pool (Enerdata, 2015h).

9.2.2 Energy Resources and Trade

Fossil Fuel Resources

As shown in Table 26, South Africa houses 3.4% of the world's total proved coal reserves with 30.2 billion tons of coal, making it the ninth-largest reserve holder globally. There are 19 official fields in South Africa, located in the eastern and north-eastern provinces. Witbank, Highveld and Ermelo coalfields account for most of South Africa's current coal production, with new infrastructure development focused on the Waterberg basin. Bituminous coal, which makes up 96% of reserves, mostly lies between 5-200m below the surface, with approximately 25% at 15-50m below the surface, which allows for low-cost mining (Eberhard, 2011). Eskom (2014) estimates that South Africa's reserves-to-production ratio is 200 years, although BP (2015) puts the ratio at 116 years.

South African coal production increased 15% from 2000 to 2014, and it was the seventh largest coal producer in 2013. It exports approximately one-third of its coal production, making it the sixth largest coal exporter globally (Enerdata, 2015h). India is the largest importer of South African coal, followed by Europe (EIA, 2015b). Approximately 44% of the domestic coal mined is consumed by the electricity sector (IDDRI & SDSN, 2014). Close to one-fifth of the country's coal production is used in its coal-to-liquids industry, primarily to produce gasoline and diesel fuels (EIA, 2015b).

Table 26: South Africa's Fossil Fuel Resources (BP, 2015).

Fossil fuel	Reserves	2014 share of world total	R/P
Oil			
Total proved reserves	2 Mt	-	-
Production	-	-	-
Consumption	29.1 Mt	0.7%	-
Natural gas			
Total proved reserves	23.3 Mtoe	-	-
Production	-	-	-
Consumption	3.7 Mtoe	0.1%	-
Coal			
Total proved reserves	30156 Mt	3.4%	116
Production	1844.6 Mtoe	46.9%	-
Consumption	89.4 Mtoe	2.3%	-

South Africa has limited reserves of natural gas. Production of gas fields in Mossel Bay started in 2009 and mostly supply Mossel Bay's gas-to-liquid plant, operated by PetroSA (South Africa's National Oil Company) (EIA, 2015b). The majority of natural gas consumed in South Africa is imported from Mozambique through a 705 km-long gas pipeline. South Africa is planning to build a pipeline to import natural gas from Namibia (Enerdata, 2015h). Natural gas is primarily used in the synthetic fuel industry to produce gasoline, which accounts for close to 60% of domestic gas consumption. From 2000 to 2014, consumption of gas rose 8.5% on average annually. Imports increased 25% from 2010 to 2014 to satisfy rising demand (Enerdata, 2015h).

Although South Africa has low natural gas reserves, there has been increasing interest in the nation's potential shale gas reserves. South Africa has the ninth largest shale gas reserves globally with an estimated 370 tcf technically recoverable shale gas resources, concentrated in the Karoo basin (EIA, 2015c). This is depicted in Figure 77. A moratorium on shale gas exploration was enacted in 2011 to study the environmental and water impacts of hydraulic fracturing. This moratorium was lifted in 2014, after a government-funded study encouraged shale gas exploration in 2012 and new regulations governing the process were put in place by 2013 (EIA, 2015b).

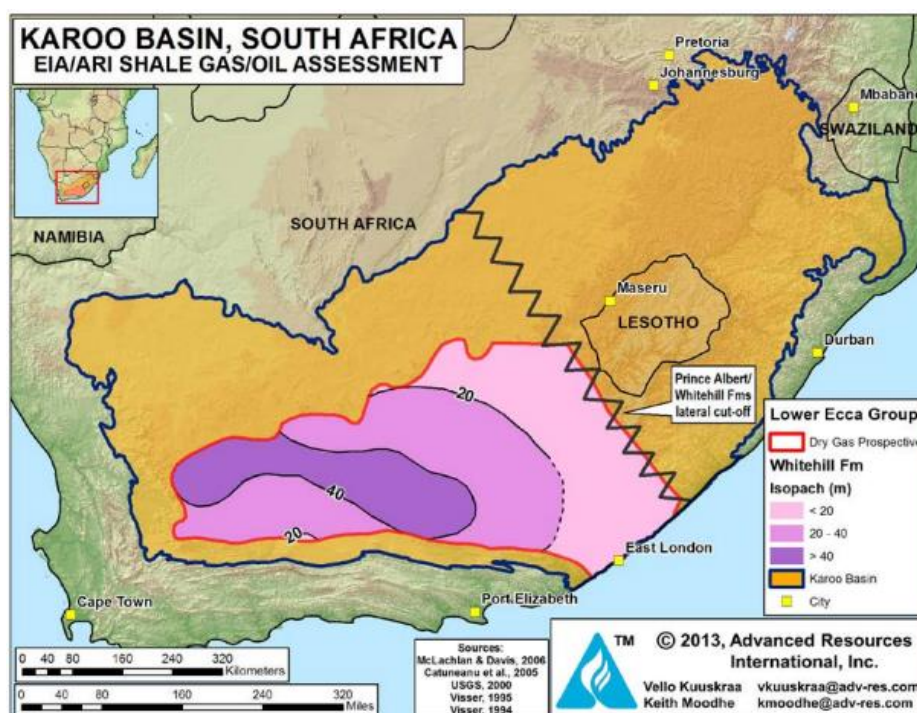


Figure 77: South Africa's shale gas reserves (EIA, 2015c).

As shown in Table 26, South Africa has limited proved oil reserves. The majority of South Africa's oil is imported from the Middle East (47%) and other African countries (49%) (EIA, 2015b). South Africa imports primarily crude oil, which it refines domestically, as it has Africa's second-largest crude oil distillation capacity at 560,000 bbl/d (EIA, 2015b; Enerdata, 2015h). The nation has a sophisticated synthetic fuel industry, producing 185,000 bbl/d, which accounts for 90% of South Africa's domestic petroleum production (EIA, 2015b). The South African petrochemical company Sasol owns and operates Secunda, one of the world's largest coal-to-liquids plants with a total capacity of 160,000 bbl/d of oil equivalent. Sasol is planning on expanding Secunda's capacity, and to build an additional coal-to-liquid plant to satisfy growing domestic demand (EIA, 2015b). In 2014, approximately coal-to-liquid processes accounted for 35% of liquid fuel production (SDSN & IDDRI, 2014). South Africa's National Oil Company, PetroSA, operates a gas-to-liquids plant at Mossel Bay, with a total capacity of 45,000 bbl/d of liquid fuels. Mossel Bay produces unleaded petrol and other synthetic fuels such as kerosene, diesel and propane (EIA, 2015b).

Renewable Energy Sources and Hydropower

South Africa has limited potential for additional large-scale hydroelectric plants, as it has already exploited most of its potential sites (Enerdata, 2015h). With an average solar radiation between 4.5 kWh/m² and 6.5 kWh/m²/d, South Africa has one of the highest solar potential globally (Enerdata, 2015h). Its concentrated solar power (CSP) potential is estimated to be 547.6 GW, with the largest resource potential (approximately 510GW) in the Northern Cape (Fluri, 2009). The Northern Cape, however, is further away from energy-demand centres, as industry is largely concentrated in the eastern provinces and coastal areas. Thus, the

implementation of large-scale CSP plants depends on the country's ability to expand and reinforce its transmission grid.

South Africa has good wind energy potential, with wind resource averages between 4.3-8.8 m/s (Enerdata, 2015f). The most favourable wind resource are along the north-western coast and the south-eastern coast (EPRI, 2012). There is an inconsistency in estimates regarding the nation's wind power potential. The government approximates that the nation's wind power potential is 3 GW, and could supply 1% of South Africa's electricity demand (DEA, 2011). Hageman (2013), however, estimates that South Africa's wind resource potential lies between 6 and 56 GW. This wide range is due to a variety of factors not limited to wind speeds, such as proximity to the transmission grid and roads. This highlights the importance of the development of the transmission grid in the deployment of renewable energy technologies in South Africa.

9.3 Energy Policy and Drivers

South Africa has suffered an electricity crisis since 2008, as electricity generation from Eskom's ageing power fleet has been unable to keep pace with rising demand. Production decreased by 5% between 2007 and 2009 due to unplanned outages, leading to widespread blackouts (Enerdata, 2015h). This problem has continued into 2015. These outages have a significant effect on its economic development, with analysts at the CIA (2015d) estimating that the country is unable to exceed a 3% growth rate unless electricity grid constraints can be resolved.

While Eskom's total installed capacity is approximately 42 GW, available capacity is much lower (EIA, 2015b). Approximately one-third of Eskom's generation capacity was offline in 2013 due to maintenance problems and poor meteorological conditions (Enerdata, 2015h). The government expects that power outages are likely to continue until 2018. This is due to maintenance problems at the Koeberg nuclear power plant (900MW), as well as continuing maintenance issues at Eskom's Majubi coal-fired power plant (Enerdata, 2015h). The problem is compounded by construction delays of the supercritical coal-fired power plants Medupi and Kusile (Enerdata, 2015h).

Eskom has increasingly relied on its four open-cycle gas turbines (OCGT) to limit power outages and meet demand during unplanned outages. These OCGTs run on diesel oil, increasing the cost of power generation. From March 2013 to 2014, Eskom spent an estimated R 10 billion (US\$ 929 million) on diesel fuel, despite only having a budget of R 2 billion (van Vuuren, 2014).

Eskom has introduced load-schedules (planned power outages) across various municipalities to avoid grid collapse (EIA, 2015b). The schedules vary according to the availability of generating units. Although these load-schedules ensure that the grid does not collapse, they have a significant impact on South Africa's economic growth. Businesses and households

across the country have bought diesel and petrol generators to power their facilities during Eskom's outages (Bates, 2014). Such generators are expensive for the private sector, and make controlling and monitoring emission levels difficult.

Addressing South Africa's electricity shortage is the main driver shaping South Africa's domestic energy policy. The government has launched energy efficiency strategies, as well as a comprehensive plan to increase installed capacity by 2030 in order to alleviate pressures on the grid. Table 27 provides an overview of South Africa's key energy policies. The following sections will outline policies relevant to energy efficiency and increasing capacity, and analyse their effectiveness and impact on South Africa's electricity system.

Table 27: South Africa's Key Energy Policies.

Date	Policy	Details
2005	National Energy Efficiency Strategy	12% reduction in final energy demand by 2015 compared to BaU Includes a 15% reduction target in power sector
2010	NESRA Pricing Policy	Aims to raise revenues for Eskom investment and reduce electricity consumption
2010 2013 update	Integrated Resource Plan (IRP), 2010-2030	Electricity plan developed by the DoE Addition of 55GW of capacity by 2030
2011	Renewable Energy IPP Procurement Programme (REIPPP)	Aims to increase IPP investment Aims to add 3725 MW of renewable energy sources by 2016, and an additional 3200 MW by 2020
Proposed	Coal Baseload IPP Procurement Programme	Aims to increase IPP investment Target to add 2500 MW of coal-fired capacity
Proposed	Gas to Power Procurement Programme	Aims to increase IPP investment Target to add 3126 MW of gas-fired capacity
Proposed 2016	Carbon tax	US\$11/tCO ₂ is expected to take effect in January 2016

Energy Efficiency

The National Energy Efficiency Strategy was passed in 2005, and revised in 2008 and 2013. The strategy mandates a 12% reduction in final energy demand for 2015 compared to a BaU scenario outlined in the LTMS (Enerdata, 2015h). The strategy includes sectorial targets, including a 15% reduction in energy demand from the power sector by 2015. Additionally, several information campaigns have been rolled out to reduce peak demand, as well as programmes to provide efficient lamps to residents. Labelling of domestic appliances is expected to commence in 2015. The Energy Efficiency and Monitoring project was launched in 2010 to measure and verify energy savings in industry (Enerdata, 2015h).

NESRA has allowed electricity price increases in order to reduce demand and fund Eskom's investment plan. In 2018, the average electricity price is projected to increase by 35% (Enerdata, 2015h). According to NESRA's pricing policy, 'electricity price increases according to the quantity of electricity bought by households. The largest consumers are charged a higher rate, whereas the electricity bills of lower consumption households are reduced' (Enerdata, 2015h). This should raise revenues for Eskom to invest in additional capacity, as well as incentivise consumers to reduce electricity consumption.

Increase Capacity

The Integrated Resource Plan (IRP) provides the blueprint for South Africa's electricity policy. South Africa does not have generation targets, relying solely on the capacity targets set by the Department of Energy in the IRP. The latest plan, outlining capacity targets for 2010-2030, calls for the diversification of generation mix to promote energy security and reduce greenhouse gas emissions.

The IRP calls for the addition of 55 GW of capacity by 2030 to meet growing demand, more than doubling generation capacity (DoE, 2013). According to the IRP, the largest increase in capacity should come from renewable energy sources, adding 18.9 GW to the electricity grid. The plan also includes 16.4 GW from coal, 9.6 GW from nuclear, 2.6 GW from imported hydropower, and 6.3 GW from gas turbines (2.4 GW from gas-CCGT, and 3.9 GW from peak-OCGT) (DoE, 2013).

A production target of 10,000 TWh of electricity from renewable energy sources in 2013 was set by the government's White Paper on Renewable Energy (Enerdata, 2015h). That year, 4.9 TWh of renewable electricity (including hydro) was produced, and so the target was not met. However, Enerdata (2015h), estimates that the target will be reached in the near future, due to the renewable energy sources projects currently under development.

Increase Private Sector Investment

Private sector investment in the South African electricity sector is seen as a way to enhance generation capacity and diversify supply. In 2007, the government mandated that 30% of all new generation capacity should be constructed by Independent Power Producers (Enerdata, 2015h). IPPs are expected to install 17 GW from renewable energy sources, co-generation, and coal-fired power plants by 2022 (Joemat-Petterson, 2015). Several procurement programmes are under development to increase the role of IPPs.

1. The Renewable Energy Independent Power Procurement Programme

A renewable energy FiT (REFIT) was implemented in 2009 to encourage private sector investment in renewable energy sources. However, uncertainty regarding Eskom's willingness to collaborate and grant power purchase agreements incorporating the FiT, as well as further regulatory uncertainty overshadowed the REFIT. Due to these uncertainties, the REFIT was

unsuccessful in encouraging any private sector investment in renewable energy projects between 2009 and 2011 (Eberhard, Kolker & Leigland, 2014).

The Renewable Energy Independent Power Procurement Program (REIPPP), a competitive tender system, replaced the REFIT in 2011. Whereas IPP procurement programmes were previously entrusted to Eskom, the REIPP is managed by the Department of Energy. This lent credibility to the programme and removed uncertainty regarding Eskom's willingness to encourage private sector involvement and thus weaken its monopoly on power generation (Eberhard, Kolker & Leigland, 2014).

In order to secure approval for a project, bidders make a bid on the level of tariff required for the project to be profitable. Furthermore, project developers have to outline how the project will satisfy a range of socio-economic criteria, such as job creation and economic growth. These factors account for 30% of the total bid value (Eberhard, Kolker & Leigland, 2014). The REIPPP is thus designed to satisfy several government objectives. First, it attempts to increase private sector involvement to alleviate pressure on the electricity system and enhance energy security. Secondly, by making procurement partially contingent on socio-economic criteria, the programme simultaneously encourages investment in regional development.

The REIPPP's initial target was to install 3725 MW of renewable energy generating capacity from IPPs by 2016. The programme has since been expanded to include an additional 3200 MW by 2020 (Enerdata, 2015h). The REIPPP mainly targets the installation of wind (3320 MW) and solar (3125 MW) (Enerdata, 2015h).

2. Coal Baseload IPP Procurement Programme

The Department of Energy aims to add 2500 MW of coal-fired capacity to the grid through the Coal Baseload IPP Procurement Programme. These privately funded plants will each have a maximum capacity of 600MW, and will be awarded power purchase agreements to sell electricity into Eskom's transmission grid (Enerdata, 2015h). The first round of bids for IPPs is expected to close in August 2015, with successful bids announced by the end of 2015.

3. Gas to Power Procurement Programme

The DoE has launched a consultation programme to design the Gas to Power Procurement Programme. This is supported by the Gas Utilisation Master Plan (GUMP), which explores scenarios for the development of gas towards 2050. This procurement programme is expected to add 3126 MW of gas-fired generation to the grid. The government aims to start the process of requesting proposals in September 2015, and launch the first bidding round in the first quarter of 2016 (Joemat-Pettersson, 2015).

Reduce Emissions

The National Climate Change Response White Paper outlined the implementation of a national carbon tax to reduce emissions. After initial delay, a tax of US\$ 11/tCO₂ is now expected to take effect in January 2016, with the rate increasing 10% annually. Approximately 60% of the power sector will be exempt from the tax until 2020 (Enerdata, 2015h).

However, as the DoE determines the electricity mix of South Africa through the Integrated Resource Plan, it is unlikely that the carbon tax will act as an incentive to invest in low-carbon generation capacity, unless the electricity sector reforms. The increased cost to Eskom for generating thermal power is likely to be passed on to consumers, if NESRA allows price adjustments (PwC, 2011). The carbon tax could encourage more private sector investment in renewable energy sources. However, as the REIPPP is a tender system, the amount of projects is limited, capping the amount of renewable energy capacity built by IPPs. The carbon tax is expected to have an impact on other industries within the economy and could thus be effective in reducing emission levels in those sectors.

9.4 Current Generation Capacity

Eskom's installed generation capacity is approximately 42 GW (Enerdata, 2014a). Due to the abundance of cheap coal in South Africa, coal-fired power plants account for 85% of total installed generation capacity. Eskom operates 13 coal-fired power plants with a combined net capacity of 36 GW (EIA, 2015b). The majority of Eskom's plants are located in the east of the country, corresponding to the location of the nation's major coal-fields. As Figure 78 shows, coal has historically been the dominant fuel source in the electricity sector. In 2014, 93% of power was generated from coal (Enerdata, 2014a). The share of coal-fired generation has decreased since 2010 as the amount of unplanned maintenance outages at Eskom's ageing facilities increased. This was compounded by maintenance issues at Eskom's Majubu coal-fired power plant (4110 MW) which came offline in 2014 after a coal silo collapsed (Enerdata, 2015h).

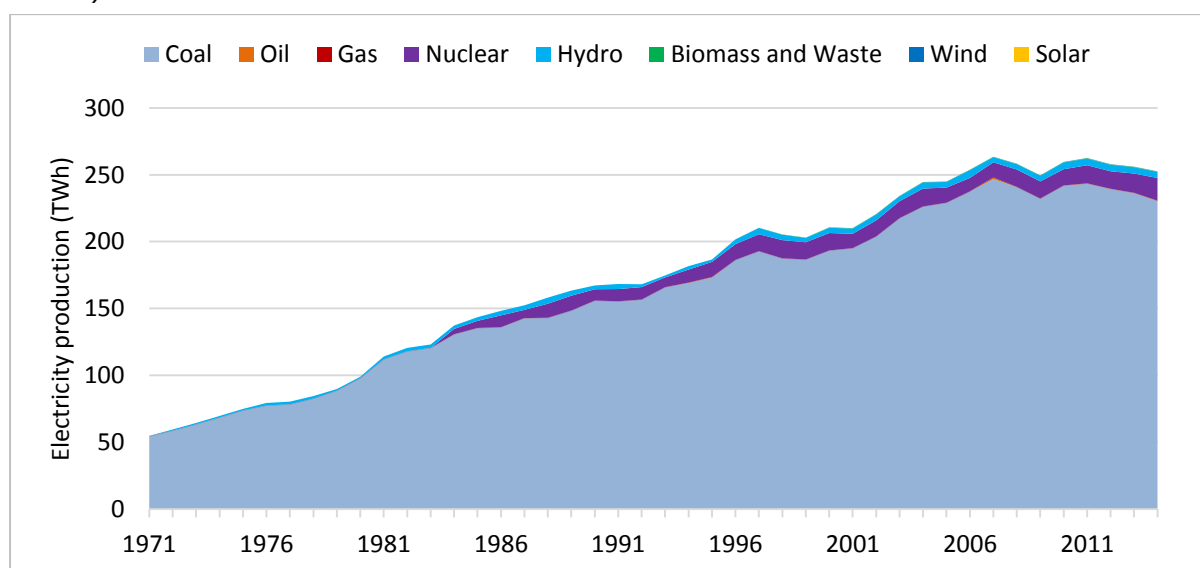


Figure 78: South Africa's Electricity Generation, 1970-2014 (Enerdata, 2014a).

As shown in Figure 79, 3.8% of installed capacity is from nuclear power (Enerdata, 2014a). This is generated at Koeberg, Africa's only nuclear power station. Koeberg has two pressurised water reactors with a combined installed capacity of 1840MW (Eskom, 2015). The nuclear power station is one of the only power stations located in the west of the country and thus supplies power primarily to the cities in the Western Cape such as Cape Town. Operational since 1985, Koeberg is rapidly ageing and regularly taken offline for maintenance and due to unforeseen tripping (van Wyk, 2013). In 2014, nuclear power represented 4.7% of power generation (Enerdata, 2014a).

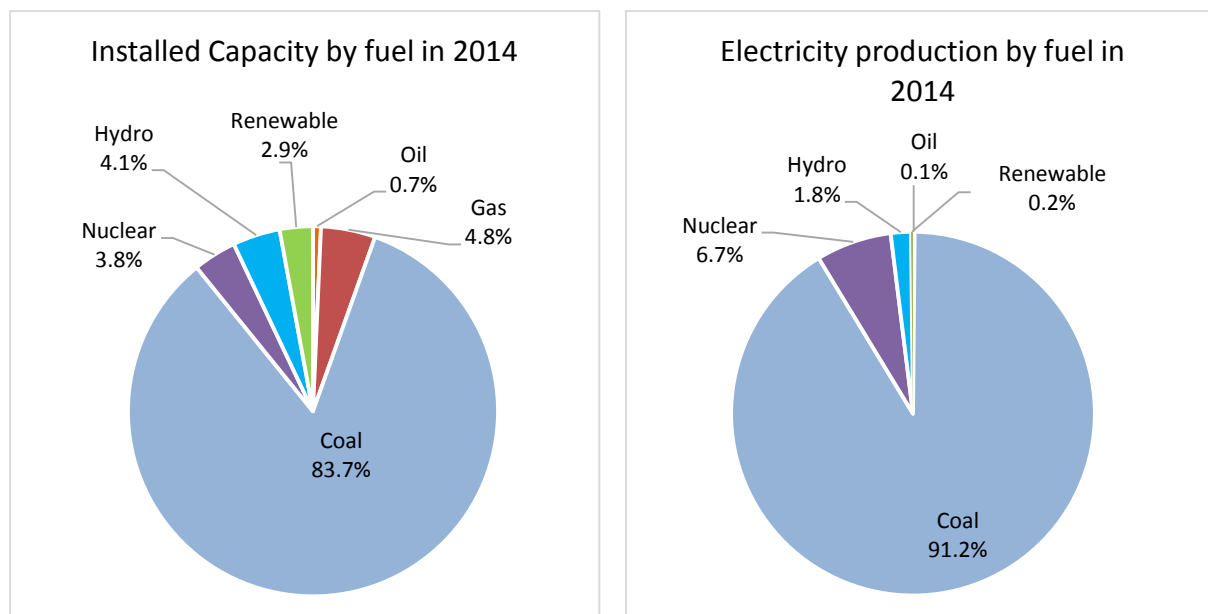


Figure 79: Comparison of installed capacity and electricity production in South Africa for 2014 (Enerdata, 2014a).

Open-cycle gas turbines are used to meet peak demand. Eskom operates four open-cycle gas turbines that run on diesel oil, with a combined installed generation capacity of 2,426 MW (Eskom, 2015). In 2014, electricity generation was 365.4 GWh (Enerdata, 2014a). Hydroelectricity and pumped hydro sites also provide power during peak demand. Eskom operates two hydroelectric plants on the Orange River. Eskom cooperates with the Department of Water and Environmental Affairs to operate the Gariep and Vanderkloof Dams, which have a combined generation capacity of 600 MW (Eskom, 2015). One pumped storage scheme is currently under construction in the Drakensberg mountains, which will have an installed generation capacity of 1332 MW (Eskom, 2015). In 2014, 2% of electricity was generated from hydroelectricity (Enerdata, 2014a).

Less than 1% of South Africa's installed capacity comes from renewable energy sources (excluding hydropower) (EIA, 2015b). Eskom currently owns and operates one wind farm with an installed capacity of 3 MW. At the end of 2014, an additional 1.6 GW of renewable energy capacity was operated by IPPs and connected to Eskom's transmission grid. Of this capacity,

600 MW is from wind sources, and 1000 MW from PV projects (Bischof-Niemz, 2015). In 2014, 0.2% of electricity was generated from renewable energy (Enerdata, 2014a).

South Africa's emission intensity of electricity is relatively high due to the large share of coal in the generation mix. In 2014, South Africa emitted 878.92 gCO₂/kWh (Enerdata, 2014a). This is higher than all countries examined in this report apart from India. Figure 80 shows a decline in both the carbon intensity of generation and total CO₂ emissions from electricity and heat production in 2009. This has been attributed to the economic recession, which caused a reduction in electricity demand (Marquard, Trollip & Winkler, 2011). Total CO₂ emissions from the sector increased from 2011 to 2012, and then declined towards 2014. It is possible that electricity shortages have influenced this trajectory, as it reduces electricity consumption.

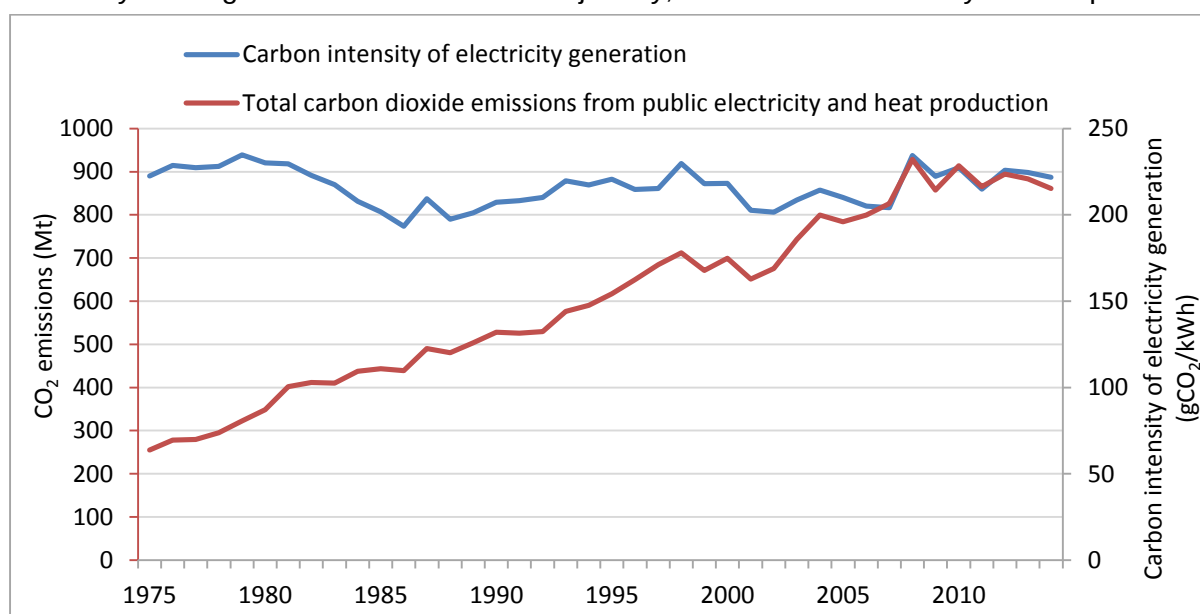


Figure 80: South Africa's carbon intensity of generation and total CO₂ emissions from electricity and heat production, 1975-2014 (Enerdata, 2015b).

9.5 Discussion and Analysis

9.5.1 Government Projected Capacity

According to the government's New Household Electricity Strategy of 2013, South Africa aims 'to achieve universal access to electricity by 2025, defined as a 97% electrification rate, 90% of which should be achieved through grid connection, and the rest through decentralised solar systems' (Enerdata, 2015h). By 2030, electricity demand is projected to be between 345-416 TWh, with peak demand averaging 61.2 GW (DoE, 2013).

As outlined, the Department of Energy published an Integrated Resource Plan outlining capacity additions in South Africa from 2010 to 2030. An update of the IRP was published in 2013, but has not been approved by Cabinet, and thus the old IRP remains the main document that influences electricity market investments (Webb et al., 2015). If capacity targets outlined

in the IRP 2010 are met, the share of fossil fuels in the electricity capacity mix will fall from 89.6% to 56.6%, with coal accounting for 46% of installed capacity (compared to 83.7% in 2014). As shown in Figure 81, the share of renewables will increase to 21%, and hydropower will account for 8.6% of total installed capacity (DoE, 2013). Details regarding planned capacity and barriers that exist to reaching the targets outlined in the IRP are outlined below.

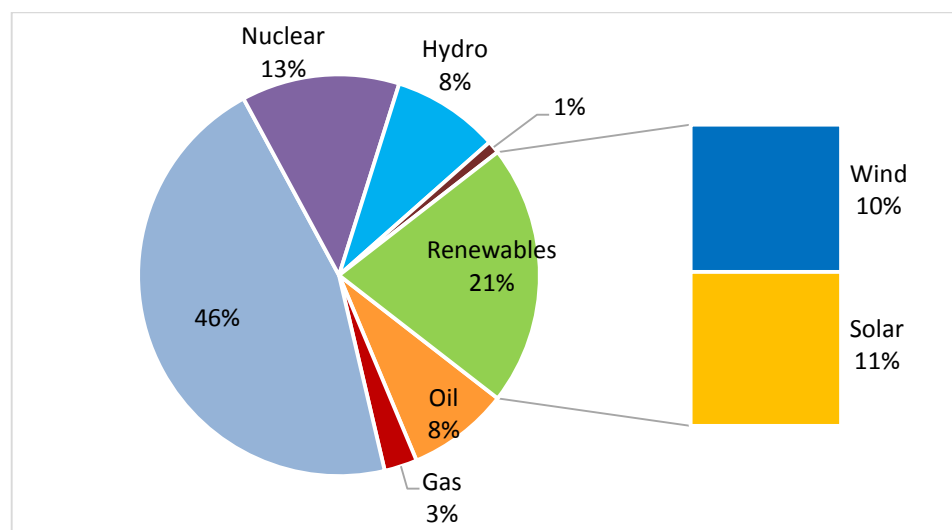


Figure 81: South Africa's installed capacity in 2030 according to the IRP 2010-2030 (DoE, 2013).

Coal-Fired Generating Capacity

The IRP 2010-2030 calls for the addition of 16 GW of capacity from coal-fired power stations. The majority of this capacity, 10 GW, has already been committed to be built. This includes the addition of 1.5 GW of capacity from Eskom's three return-to-service plants at Camden-1, Grootvelei and Komati-1 (DoE, 2013).

While an additional 8.6 GW of coal-fired generation was initially expected to come online in 2011, the latest IRP has been updated to reflect the delays Eskom's Medupi (4788 MW) and Kusile (4800 MW) power stations are facing due to financial difficulties and labour strikes (Enerdata, 2015h). These plants are now expected to be commissioned between 2013 and 2020, although uncertainty still exists regarding the feasibility of this target. The combined generation capacity of these two plants, 9588MW, is equal to approximately 25% of currently installed capacity (IDDRI & SDSN, 2014). Medupi and Kusile are super-critical coal-fired power stations. Both plants will be fitted with flue-gas desulphurisation technology to remove sulphur dioxide emissions, and Kusile is intended to be 'carbon capture and storage ready', meaning that it can be retrofitted at a later date (Eskom, 2011).

The updated IRP decreased the total installed coal-fired generation capacity from 6.2 GW to 2.5 GW (Webb et al., 2015). This is to reflect a lower electricity demand forecast towards 2030

than anticipated in the 2010 IRP. This coal-fired capacity is expected to come from imports, and fluidised bed combustion and pulverised fuel technologies, and are expected to come online between 2014 and 2030 (DoE, 2013).

Eskom's coal-fired power fleet is ageing. However, six out of Eskom's thirteen coal-fired power plants, totalling 25 GW, are still expected to be operational in 2030. Furthermore, the DoE is exploring the option of extending the life of Eskom's existing power fleet. This would have significant implications on emission levels, as the majority of Eskom's power stations are coal-fired and use less efficient technologies (DoE, 2013). South Africa is exploring the option of developing carbon capture and storage (CCS) technologies. The South African Centre for Carbon Capture and Storage (SACCCS) aims to construct a CCS Demonstration Plant by 2020 (Enerdata, 2015h). While Eskom's new-build plants Kusile and Medupi are CCS ready, Eskom's older coal-fired plants are not. Thus, CCS technologies would not reduce emissions if the DoE opts to extend the life of Eskom's existing power fleet.

Gas and Diesel Generating Capacity

The IRP envisages that an additional 6 GW of capacity will come from open-cycle gas turbines and combined-cycle gas turbines by 2030. By 2016, two projects run by GDF Suiz totalling 1 GW of power are expected to come online (Enerdata, 2015h). These are run on diesel (DoE, 2013). The remaining 5 GW is expected to come online between 2019 and 2030.

South Africa's significant shale gas reserves present an opportunity to decrease the country's reliance on imports from Mozambique. The exploration of these reserves, however, faces significant challenges. Five companies have submitted applications to start exploring the shale gas resources of the Karoo Basin. Due to regulatory difficulties, however, Shell decided to withdraw its application in 2015 (Enerdata, 2015h). Thus, it seems likely that South Africa will continue to rely on imports for the majority of its natural gas consumption, which in turn impacts the profitability of its new power capacity.

Nuclear Power Generating Capacity

Eskom intends to extend the lifespan of its existing nuclear plant Koeberg by installing new steam generators. The French company Areva was contracted to install the new generators and plans to complete the project by 2018 (Enerdata, 2015h). This would extend Koeberg's lifespan by approximately ten years, keeping 1.8 GW of baseload nuclear capacity online.

According to the IRP 2010-2030, an additional 9.6 GW of capacity should be built by 2030, accounting for 23% of new generation capacity between 2010 and 2030. The first plant is

expected to come online in 2023 (DoE, 2013). If achieved, total installed nuclear capacity in 2030 would be 11.4 GW, accounting for 13% of total installed capacity. Eskom is carrying out Environmental Impact Assessments at three sites to identify suitable locations for new nuclear capacity. These sites are in Bantamslip (Western Cape), Duinefontein (located next to Koeberg), and Thyspunt (Eastern Cape) (van Wyk, 2014). In 2010, draft EIA's were released for public consultation which seem to favour Thyspunt.

The government has signed intergovernmental agreements with China, France, Russia, the US, and South Korea in order to encourage skills development and training, trade, and solidify interest in procurement (Webb et al., 2015). According to the DoE, contracts to construct new nuclear plants will be awarded by March 2016.

Despite these agreements, and the promise of finalising the nuclear procurement process in 2016, South Africa's nuclear plans face significant uncertainty. While the DoE's IRP mandates the installation of 9.6 GW of new nuclear capacity, the updated report (published in 2013) also states that 'no new nuclear base-load capacity is required until after 2025 and that there are alternative options, such as regional hydro, that can fulfil the requirement and allow further exploration of the shale gas potential before prematurely committing to a technology that may be redundant if the electricity demand expectations do not materialise' (DoE, 2013). This indicates that there is a lack of consensus within the DoE and within the government in general regarding the need to construct new nuclear capacity.

Furthermore, local actors have criticised the nuclear procurement process as lacking transparency and accountability. For example, the Russian company Rosatom announced in 2014 that it had procured the rights to construct eight reactors in South Africa, although the DoE denies that such a contract has been rewarded (Brock, 2015). These conflicting statements have caused concern and led critics to believe the procurement process is possibly corrupt. This has raised concerns regarding the cost of nuclear power, as there is no public participation or analysis by third-party institutions of the potential nuclear contracts being made (Brock, 2015).

With uncertainty within the government itself regarding the need to install nuclear, as well as concerns raised by other actors, it is unclear whether South Africa will install 9.6 GW of new nuclear capacity. The effect this has on the overall electricity mix depends on whether this capacity will be replaced by coal-fired power plants, from renewable energy sources, or gas-fired power stations.

Renewable Energy Sources (Including Hydropower)

According to the updated IRP, 18.9 GW of capacity from renewable energy sources (including hydropower) should be added to the grid by 2030. This includes the construction of an additional 8.4 GW of wind power, and 9.4 GW of solar (DoE, 2013). Achieving this target would increase installed wind capacity to 9.2 GW and solar to 9.6 GW in 2030. Eskom's Sere Wind Facility became fully operational in 2015, adding 100 MW of renewable energy sources capacity to the grid. Eskom is also constructing a concentrated solar plant, which will supply 100 MW of power (Eskom, 2011).

Imported hydropower is expected to supply an additional 2.6 GW. Mozambique and Zambia identified as potential suppliers for large-scale generation (Joemat-Pettersson, 2015). The government is also collaborating with the Democratic Republic of Congo on the Grand Inga hydropower project (Joemat-Pettersson, 2015). Due to South Africa's limited hydropower resources, local generation is likely to come from small plants. The White Paper on Renewable Energy (2003) outlines several domestic locations for small hydropower plants, which would each generate less than 10 MW.

The majority of new renewable energy capacity is expected to be constructed by IPPs. Four bidding rounds have occurred since the launch of the REIPPP, through which 5.2 GW of renewable energy generating capacity has been procured (Joemat-Pettersson, 2015). Of this, 1827 MW from 37 projects had been connected to the grid in May 2015. By mid-2016, 47 projects are expected to be fully operational and contribute 7000 GWh per annum to the grid (Joemat-Pettersson, 2015). The fifth bidding round of the REIPPP is scheduled for the second quarter of 2016. The REIPPP is expected to procure an additional 6.3 GW in order to reach the IRP target for renewable energy sources (Climate Action Tracker, 2015b).

The REIPPP has been successful in encouraging private sector investment in the electricity sector, and diversified South Africa's power generation mix. Due to the programme, South Africa has one of the highest renewable energy generating capacity IPP investment rates globally (Eberhard, Kolker & Leigland, 2014). According to government statistics, R170 billion in capital investment had been secured from 2011-2015 through the programme. Furthermore, investment in local development such as health care, infrastructure, and skills development has increased. This is in part attributed to the socio-economic criteria the projects have to adhere to when securing bids (Joemat-Pettersson, 2015).

The price of renewable energy has decreased since the implementation of the REIPPP. For example, the average bid price for solar photovoltaic (PV) declined by 68%, wind bid prices

decreased by 42%, and the bid price for concentrated solar power fell by 45.6% over three bidding phases between 2011 and 2014 (Eberhard, Kolker & Leigland, 2014). The decrease in the cost of renewable energy was driven by competition in the procurement programme process, but also due to decreasing costs of renewable energy equipment and increasing economies of scale (Eberhard, Kolker & Leigland, 2014). This is encouraging for potential future growth of renewable energy generation in South Africa, as renewable energy sources will potentially be able to compete with cheap coal-fired power generation.

Increased renewable energy capacity has also resulted in other financial benefits, in the form of fuel savings and macroeconomic benefits. In 2014, for example, renewable energy generation replaced 1.07 TWh of electricity from diesel-fired gas turbines employed during peak demand, which saved R 3.33 billion (equivalent to approximately US\$ 0.26 billion) in diesel fuel costs (Bischof-Niemz, 2015). Furthermore, renewable energy sources provided additional capacity, and thus resulted in a reduction in the amount of hours during which load shedding would have had to occur to balance the electricity grid. This reduction in the interruption of electricity supply resulted in macroeconomic savings of R1.6 billion (equivalent to approximately US\$ 0.13 billion) (Bischof-Niemz, 2015). The CSIR Energy Centre calculated that the total financial benefit of renewable energy in 2014 was R 5.3 billion. As tariff payments to IPPs for renewable energy generation totalled R 4.5 billion, renewable energy resulted in a net financial gain in South Africa in 2014 (Bischof-Niemz, 2015). Renewable energy sources thus provide a cheap, reliable source of power generation that can alleviate current pressures on the electricity grid.

However, the future success of the REIPPP in encouraging generation from renewable energy sources depends on the strength of Eskom's transmission grid, and Eskom's financial circumstances. If the transmission grid is not developed further, REIPPP projects face the risk of being installed but not connected to the grid. Furthermore, if Eskom's financial situation continues to worsen, it might not be able to continue purchasing generation from IPPs (Eberhard, Kolker & Leigland, 2014). Thus, whilst the REIPPP has successfully increased installed renewable energy capacity in South Africa since 2011, there is uncertainty regarding the actual amount generated and utilised from these sources, as well as the future stability of the programme.

Implications for Emission Levels

As outlined, the LTMS provides the framework for South Africa's scenario development regarding future emission levels and mitigation potential. The electricity sector is the only sector of the economy for which alternative emission level scenarios have been developed.

These have been developed during the IRP modeling. As shown in Figure 82, these scenarios lead to differing levels of emissions from the power sector towards 2030.

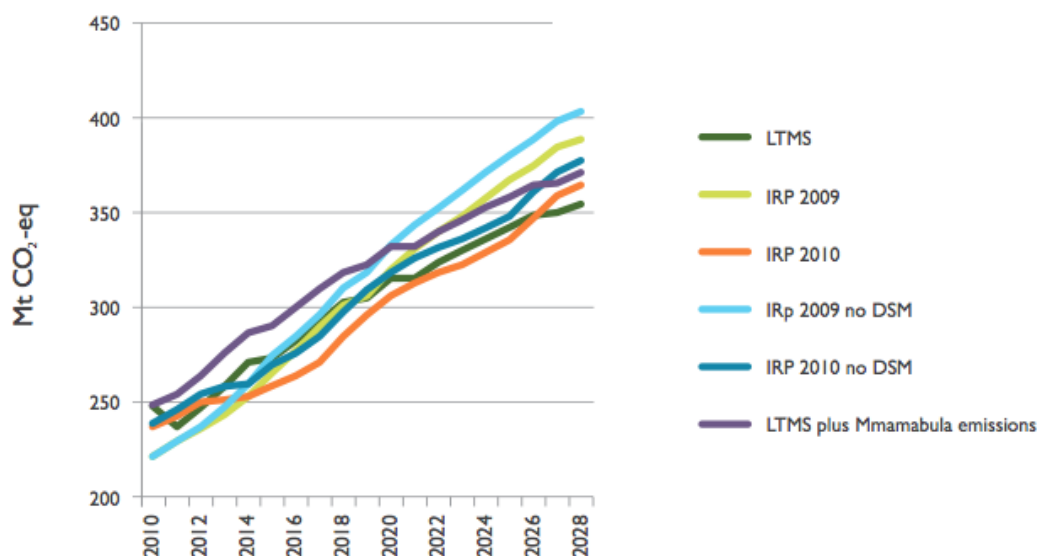


Figure 82: Government BaU Scenario Projections of Emission Levels from the Power Sector, 2010-2028 (Marquard, Trollip & Winkler, 2011)

Figure 82 highlights the difficulty in predicting future power sector emission levels, as these calculations are based on differing assumptions. For example, while the LTMS included an assumption that electricity would be imported from Botswana's Mmamabula coal-fired power station, emissions from this source were not included in emission level calculations (Marquard, Trollip & Winkler, 2011). As shown, LTMS emission projections increase when these emissions are taken into account. Furthermore, the IRP 2009 and 2010 BaU scenarios included demand-side management (DSM) measures, which were not included in the LTMS study.

The IRP recommends supporting coal projects situated in other countries in the region, so that electricity can be imported through the SAPP. This is seen as an attractive option as emissions from this generation will not count towards South Africa's total (DoE, 2013). While this is true, this would not reduce global emission levels.

The studies also have different assumptions regarding the role of renewable energy technologies. At the time of the LTMS publication, wind- and PV-generation technologies were relatively expensive and thus calculated to have limited potential. The IRP predicts that the cost of these technologies will continue declining over the next two decades, and thus the electricity plan outlines a larger role for renewable technology in the electricity mix (Marquard, Trollip & Winkler, 2011). The mitigation potential of the power sector remains higher in the LTMS than in the IRP, however, due to the LTMS assumption that no new coal-fired

generation is constructed in South Africa. This is inconsistent with the current construction of two new supercritical power plants at Medupi and Kusile (Marquard, Trollip & Winkler, 2011). It is thus likely that emission levels from the electricity sector will be higher than the range specified by the LTMS.

Despite these differing assumptions, however, Figure 82 shows that the BaU scenarios developed by the IRP and the LTMS both predict that total emissions from the power sector are likely to continue increasing towards 2030. This is due to the uncertainty surrounding the growth in low-carbon generation, as it is unclear whether South Africa's nuclear capacity will expand to provide more baseload capacity. Furthermore, coal-fired generation remains cost-competitive in the current market. Although carbon intensity of generation is likely to decrease as new generating capacity employ supercritical technology, total emissions from the power sector are likely to continue increasing towards 2030 (Marquard, Trollip & Winkler, 2011).

9.5.2 Enerdata Scenarios

Enerdata has developed three main scenarios for the electricity sector in South Africa towards 2040 (refer to Chapter 3 for an explanation of these scenarios).

Figure 83 displays South Africa's electricity generation capacity according to Enerdata scenarios and government projections. It can be seen that the government IRP capacity targets lead to a lower share of total thermal installed capacity in 2030 than the Enerdata scenarios predict. Furthermore, if South Africa meets the capacity targets outlined in the IRP, the share of firm low-carbon increases to 21%. It can be seen that Enerdata's scenarios are less optimistic about the share of firm low-carbon sources. Enerdata's scenarios will now be examined in detail.

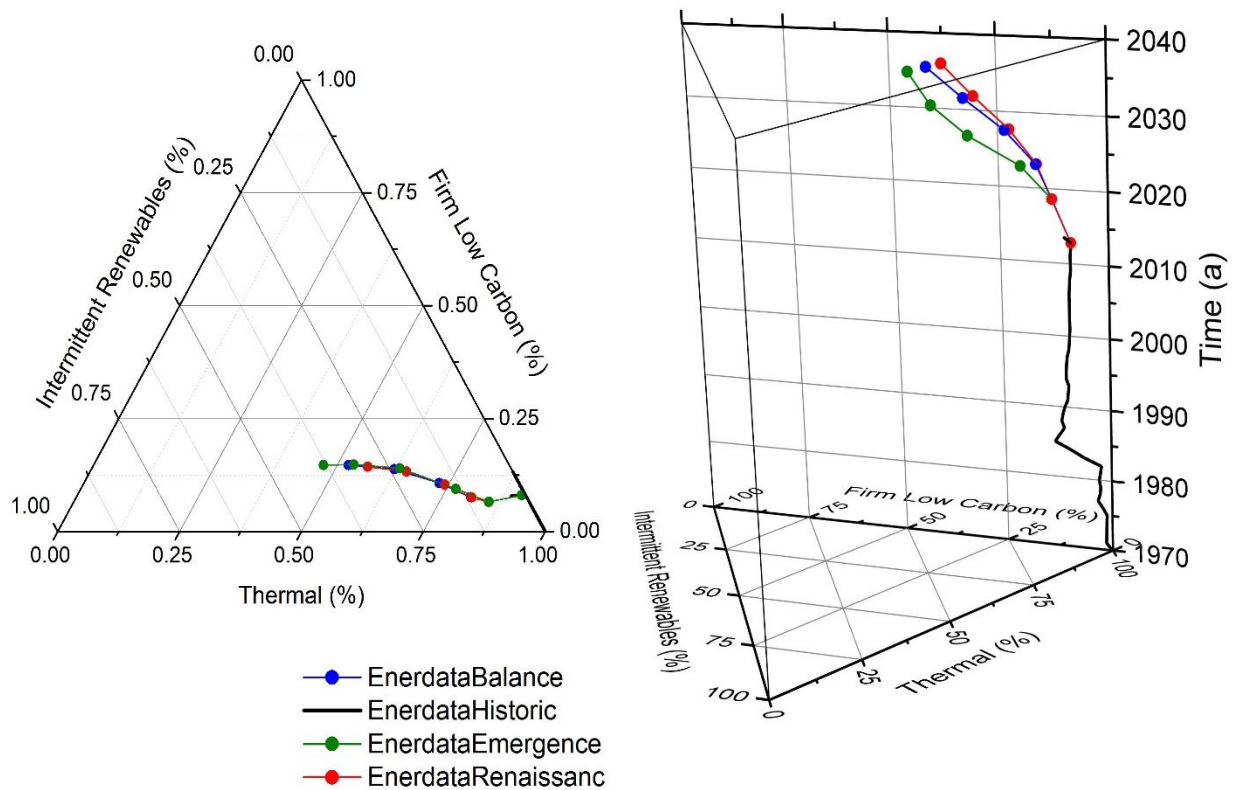


Figure 83: South Africa's electricity generation capacity according to scenarios, 1970-2040 (DoE, 2013; Enerdata, 2014a).

As shown in Figure 84, all three Enerdata scenarios expect coal-fired generation capacity to remain relatively stable after 2020. While coal-fired generation capacity is expected to increase from 41 GW in 2013 to 47 GW in 2020, total installed coal-fired capacity remains between 46 and 48 GW in all Enerdata scenarios (Enerdata, 2014a). Balance and Emergence project coal-fired capacity to fall after 2030, while Renaissance predicts a decline in generation capacity after 2035.

The share of nuclear power capacity is expected to increase in all scenarios to increase baseload capacity. Enerdata's scenarios do not expect nuclear power capacity to increase to 9.6 GW in 2030, even though this is a target set in the IRP. As outlined, it seems likely that the IRP nuclear target will not be reached and thus it is likely that the Balance and Renaissance scenario, which predict a smaller share for nuclear power than Emergence, more closely follows South Africa's current capacity trajectory. The IRP's nuclear target is more consistent with Enerdata's scenarios in 2040 rather than 2030.

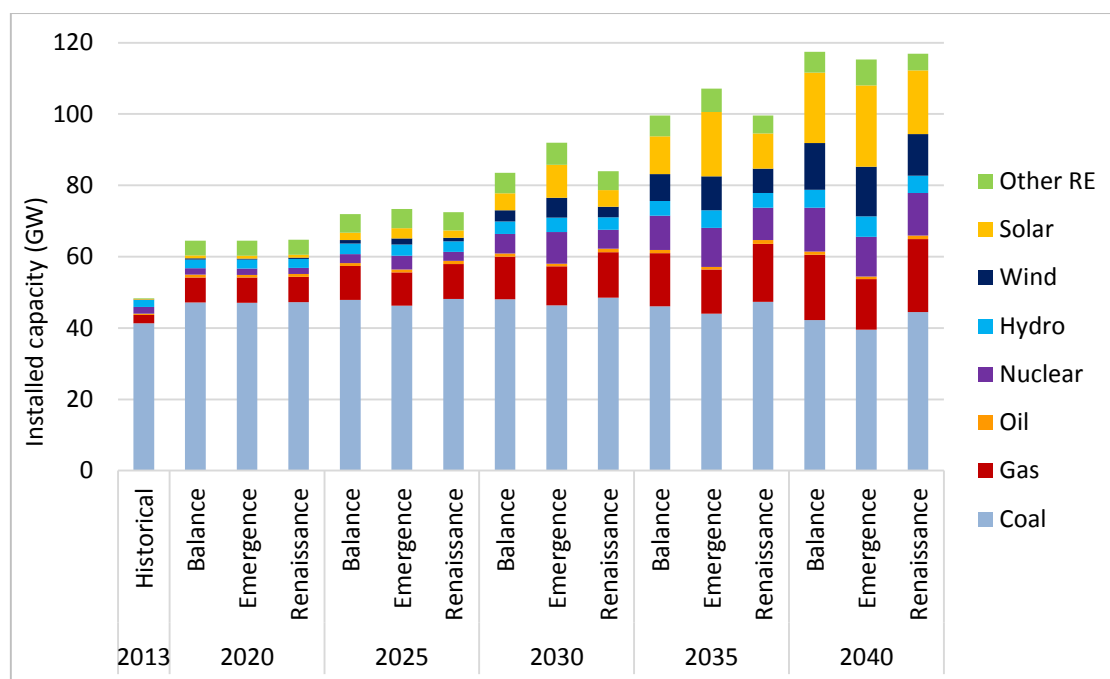


Figure 84: Enerdata's scenarios of South Africa's installed capacity, 2013-2040 (Enerdata, 2014a).

As shown in Figure 84, all three Enerdata scenarios predict a higher share of thermal installed capacity in 2030 than the targets outlined in the IRP. If the renewable energy targets identified in the IRP are met, however, approximately 22% of South Africa's installed capacity in 2030 will come from intermittent renewables. This is similar to Emergence, which projects that renewable energy sources will account for 22.8% of installed capacity (Enerdata, 2014). These differing installed capacity projections have significant impacts on forecasts regarding power sector emissions, as displayed in Figure 85.

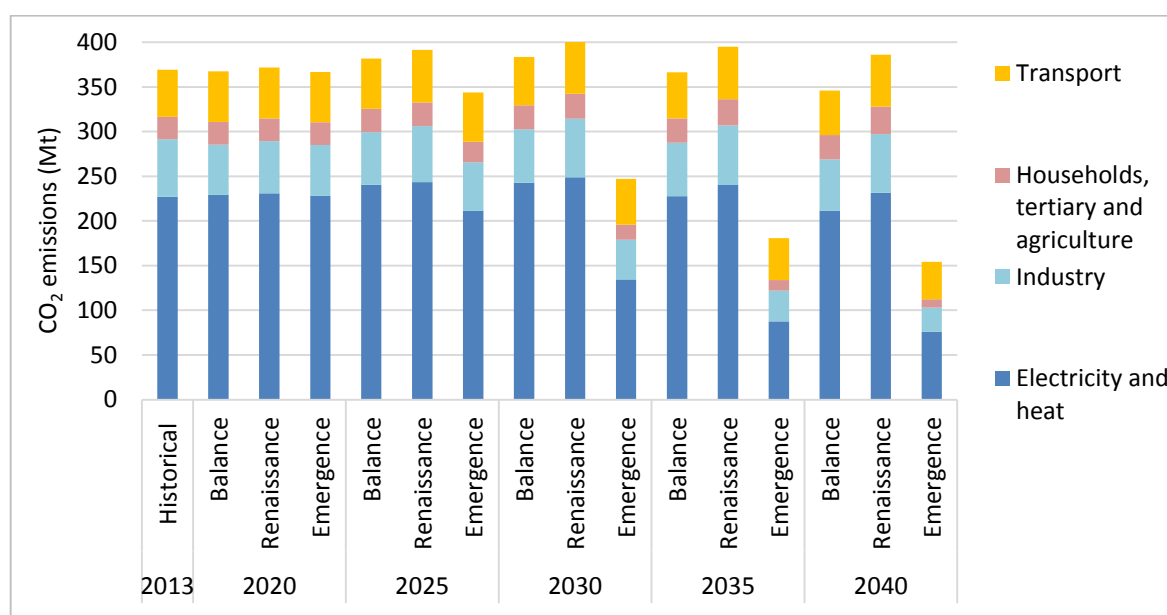


Figure 85: Enerdata's scenario comparison of sectoral emissions, 2013-2040 (Enerdata, 2014a).

As Figure 85 shows, emission levels from industry, transport, and households, tertiary and agriculture are expected to remain relatively similar towards 2035. In 2040, the Emergence scenario envisages that emissions from industry declines. The largest reduction in emission levels is envisaged to come from the power sector. In the Emergence scenario, power sector emissions are expected to decline after 2025. The reductions in this scenario highlight the mitigation potential of the electricity sector, and the effect that emissions abatement in this sector would have on economy-wide emission levels. As outlined, emission levels from the power sector are projected to continue rising towards 2030 in all government projections. This aligns more closely with the Balance and Renaissance scenarios.

9.6 Summary

The main driver shaping South Africa's energy policies is the need to increase capacity to address the country's electricity crisis. Although the country has long-term climate change targets towards 2050 in place, these are contingent on South Africa receiving support from developed countries. Climate change concerns do not seem to be a major driver in the diversification of the country's electricity mix.

Electricity capacity targets are determined by the Department of Energy, and outlined in the Integrated Resource Plan. The government expects power outages to continue until 2018, due to maintenance issues at the Koeberg nuclear plant and construction delays at the supercritical coal-fired power plants Medupi and Kusile. Significant uncertainty exists surrounding the achievability of the capacity targets outlined in the IRP. Particularly, the nuclear capacity targets outlined in the IRP are unlikely to be met by 2030. Although the government has signed intergovernmental agreements with several countries, no contract has been officially awarded to construct new nuclear plants in South Africa. Local actors have criticised the nuclear procurement process for lacking transparency and accountability, raising concerns regarding the cost of nuclear power. Furthermore, there is uncertainty about whether nuclear power capacity is necessary as base-load power, as electricity demand is growing at a lower rate than previously expected.

The government envisages that Independent Power Producers will play a larger role in supplying electricity in the future. The success of increasing renewable energy sources through private sector investment, however, depends on Eskom's financial stability and the strength of the transmission grid.

Delays at Eskom's two new-build supercritical power plants due to financial constraints suggest that further investment in large-scale coal-fired generation is unlikely. Extending the life of Eskom's ageing coal-fired power fleet would keep subcritical plants online. This would cause emission levels from the power sectors to remain high. Government business as usual projections regarding power sector emission levels were developed in the IRP and the Long Term Mitigation Scenario projections. All of these scenarios predict that emission levels from the power sector will continue to increase towards 2030.

10 UNITED KINGDOM

Highlights

- The United Kingdom (UK) has a stable, predominantly service based economy. The GDP was £1,791,490 million in 2014, with a growth rate of 2.6% (CIA, 2015). The energy industry contributed 3.3% to the overall GDP in 2013 (Department of Energy & Climate Change, 2014).
- The current electricity mix includes 61% from fossil fuels, 19% nuclear, 13% renewables, and 8% other sources (Department of Energy & Climate Change, 2015). Total greenhouse gas emissions have been starting to decline since 2008. In 2013 one third of emissions (189.7 MtCO₂-eq of total 568.3 MtCO₂-eq) came from the energy supply sector.
- With the Climate Change Act of 2008, the government has set strict and legally binding absolute carbon emission budgets up to 2027 and a reduction goal of 80% comparing to a 1990 level by 2050.
- A range of energy policies are concerned with supporting low-carbon electricity generating technologies, such as renewables, nuclear, and CCS. Regulations are pushing for a system change towards low-carbon generation, however, in compliance with competitive markets and secured electricity supply.
- Uncertainties and incoherence in energy related policies have partly delayed action and investment instead of fostering development. However, intermittent renewable energy sources, mainly wind power, are expected to grow, accounting for a significant share of > 40% in the installed capacity mix in the 2020s and beyond.
- The proportion of gas-fired and nuclear power stations are likely to increase, as unabated coal fades out entirely by 2030. CCS technology is seen to be deployed from 2020 onwards, accounting for approximately 8% of the capacity share in 2035.

10.1 Background

Since the heights of the British Empire in the 19th century and its transition to the Commonwealth nations the United Kingdom (UK) has globally influenced political and economic landscape. In the early 20th century, the UK shifted from the leading industrial power to a dominant position in world finance and trading (Fessler, 2003).

As constitutional monarchy, the UK has until today remained its monarchical structures on the highest decision-making level. However, mainly functioning with democratic elements its hierarchical model is often referred to as the Westminster system, constituted of a two-chamber parliament and the monarch. As part of the executive the House of Commons and House of Lords discuss and vote on bills, also energy policy related bills, which are then signed by the monarch before becoming a law.

Internationally, the UK is founding member of the NATO and the US Security Council. In 1973, the UK joined the European Union (EU), however, it is not part of the European Economic and Monetary Union but remains in an informal bond with the former pound sterling area (CIA, 2015; Newton, 1985). The UK's economy today is predominantly service based with a total GDP in 2014 of £1,791,490 million or £26,385 per capita (Office for National Statistics, 2015).

In the past decades, the UK's energy sector has experienced significant changes in its generation capacity. The main energy sources today, however, are still fossil fuels. Electricity in 2014 came to 61% from fossil fuels (coal, oil gas), to 19% from nuclear, to 11% from wind, 2% from hydro, and 8% from other sources (Department of Energy & Climate Change, 2015).

In compliance with global efforts to mitigate climate change, the UK is pursuing a path of decarbonisation, particularly in the energy sector. Being one of the first countries with energy legislations restricting greenhouse gas emissions, the UK is playing a vanguard role in international energy politics.

10.1.1 Emissions

Total greenhouse gas emissions in the UK by end-user were 568.3 MtCO₂-eq in 2013, of which 189.7 MtCO₂-eq came from the UK energy supply sector (Department of Energy & Climate Change, 2015). The emissions from agriculture accounted for 53.7 MtCO₂-eq, transport accounted for 116.8 MtCO₂-eq, businesses (90.9), industrial (12.8), and public processes (9.5) for 103.7 MtCO₂-eq, and for the residential (77.6) and waste management (22.6) for 100.2 MtCO₂-eq. Land use had a positive effect on the total greenhouse gas emissions and reduced the total by 5.3 MtCO₂-eq in 2013 (Department of Energy & Climate Change, 2015).

As indicated in Figure 86, since the deindustrialisation of the UK, total CO₂ emissions have been rather constant. However, the mitigation of anthropogenic climate change through decarbonisation has been an increasingly important driver pushing for environmentally benign energy sources.

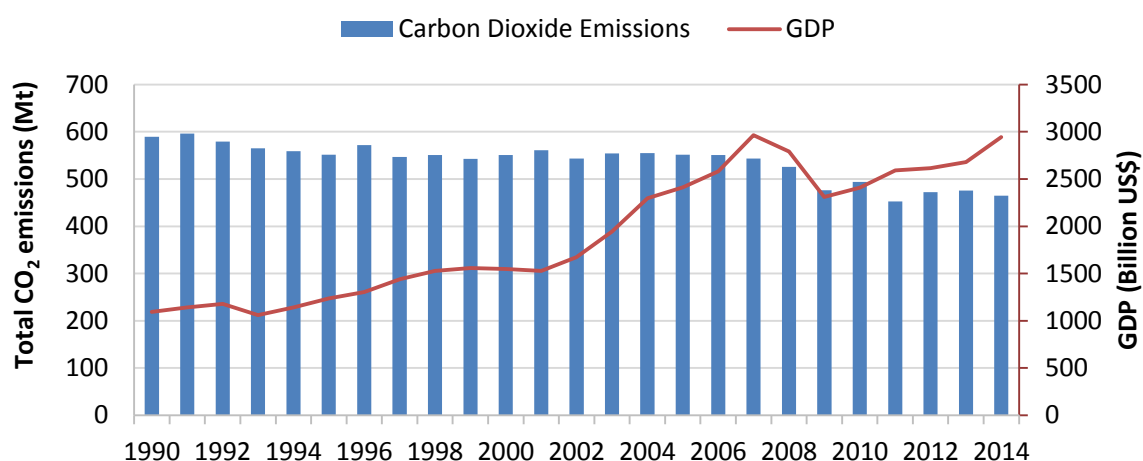


Figure 86: The UK's GDP (World Bank, 2015) and CO₂ emissions (Department of Energy & Climate Change, 2015) 1990-2014.

In 2012 the main fuels used for electricity generation were coal and gas, meeting 40%, respectively 28%, of total annual electricity demand (International Energy Agency). Figure 87 illustrates the share in CO₂ emissions coming from electricity generation with the largest part coming from coal power plants. However, a shift to increased gas utilisation as the less carbon

intensive fuel is becoming visible. Emissions from natural gas-fired power plants are approximately 350 gCO₂/kWh (International Energy Agency GHG, 2012), whereas electricity from coal-fired power stations emit approximately 750 gCO₂/kWh (International Energy Agency GHG, 2014). In 2014, coal and gas accounted in equal parts for 30% of electricity generation (Department of Energy & Climate Change, 2015).

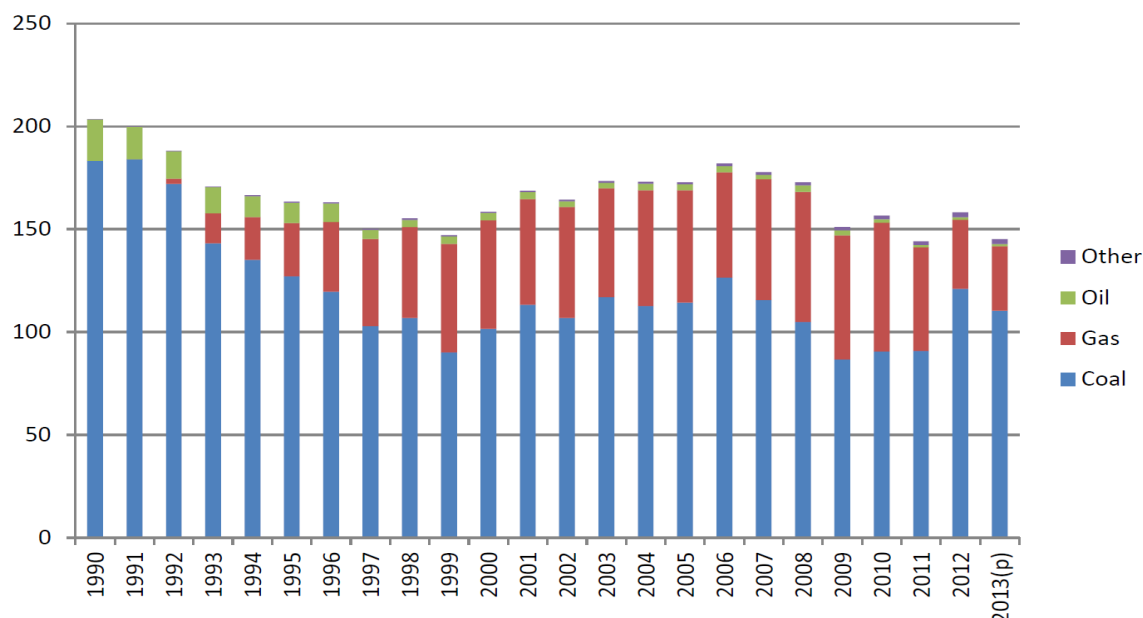


Figure 87: Carbon dioxide emissions from electricity generation in the UK from 1990-2014 (Department of Energy & Climate Change, 2014).

10.1.2 Climate Change Targets

The UK has stated the reduction of carbon emissions as legally binding according to the Climate Change Act. Under the Labour government in 2008, the Climate Change Act was the first energy bill to set strict emission targets. A reduction goal of 80% (compared to the 1990 level) by 2050, and 34% by 2020, even exceeds the EU targets. As agreed upon in the EU Effort Sharing Decision (ESD) in 2008, the UK committed to reduce 16% of emissions by 2020 (European Parliament, 2009).

Five carbon budgets were introduced as a step-wise allocation of the carbon reduction targets. The first carbon budget has been met with a net carbon account of 2,982 MtCO₂e in the period of 2008 - 2012 staying below the legislated 3,108 MtCO₂e (Committee on Climate Change, 2014).

Table 28: UK Carbon Budgets for 2008 – 2027 (Department of Energy & Climate Change, 2015)

Budget Phase	Budget 1	Budget 2	Budget 3	Budget 4
Time Horizon	2008-2012	2013-2017	2018-2022	2023-2027
Level (MtCO ₂ -eq.)	3,018	2,782	2,544	1,950
Equivalent average annual emissions (MtCO ₂ -eq.)	603.6	556.4	508.8	390.0

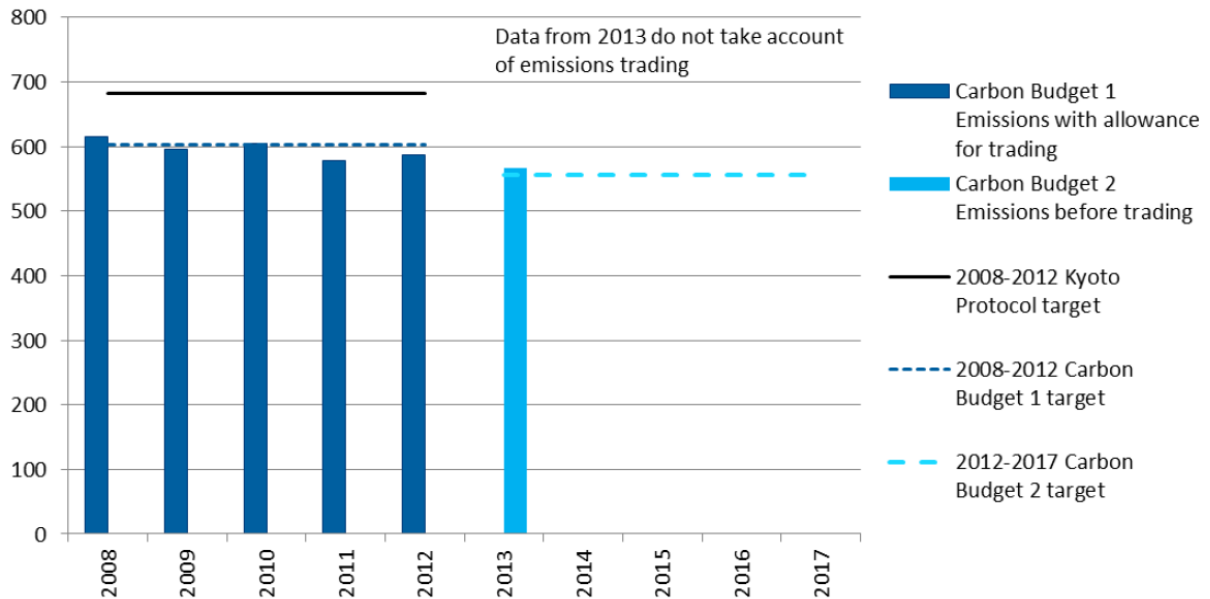


Figure 88: Illustration of UK Carbon Budgets (Department of Energy & Climate Change, 2015). The first budgets has been met.

Another element of the Climate Change Act was the establishment of an independent 'Committee on Climate Change' (CCC) in charge of evaluating possible energy transition strategies and consulting the UK government. The first parliamentary report recommended an extensive decarbonisation of the power sector by 2030 (Committee on Climate Change, 2013). This is further specified to happen through off-shore wind commercialisation and the depletion of CCS in the latest CCC report (Committee on Climate Change, 2014).

10.2 UK's Electricity System

10.2.1 Electricity Market

The UK's electricity market is organised on the two major levels of a wholesale and a retail market. In general, the wholesale market facilitates the selling of electricity from producers to utility companies or competitive electricity providers. Furthermore, the retail market links the resellers and the end-consumer. However, in some cases links are not as black and white, as utility companies might operate power production facilities or large production firms trade directly in the retail market.

Since 1990's the wholesale electricity market in the UK is privatised, free and competitive. With the introduction of the New Electricity Trading Arrangements (NETA) in 2001, the market was opened from a centralised pool design to bilateral structure. However, up to today only a few major organisations control the power generation and transmission (International Energy Agency, 2005). The "Big Six" energy production companies in the UK are Centrica with British Gas, EDF Energy, E.ON, RWE npower, Scottish Power, and SSE (previously Scottish and Southern Electric). All six firms are vertically integrated and work in electricity generation and

retail (Competition & Markets Authority, 2015). Figure 89 and Figure 90 show the regional allocation of the transmission and distribution network operators across the UK.

It is the responsibility of the system operators, for example National Grid in Great Britain (GB), to ensure electricity availability and balance a supply and demand mismatch. The Office of Gas and Electricity Markets (Ofgem) on the other hand, controls the gas and electricity prices and sets a cap for the revenues of the four (transmission) system operators. The UK's retail market was fully privatised in 1999 (Office of Gas and Electricity Markets, 2015). Since then, the end consumer of electricity is able to choose from a range of electricity suppliers. These function as market link and make use of the transmission and distribution network in order to deliver the electricity to their customers. Currently 25 electricity suppliers are selling their service to domestic and non-domestic customers (Competition & Markets Authority, 2015).

Electricity Transmission

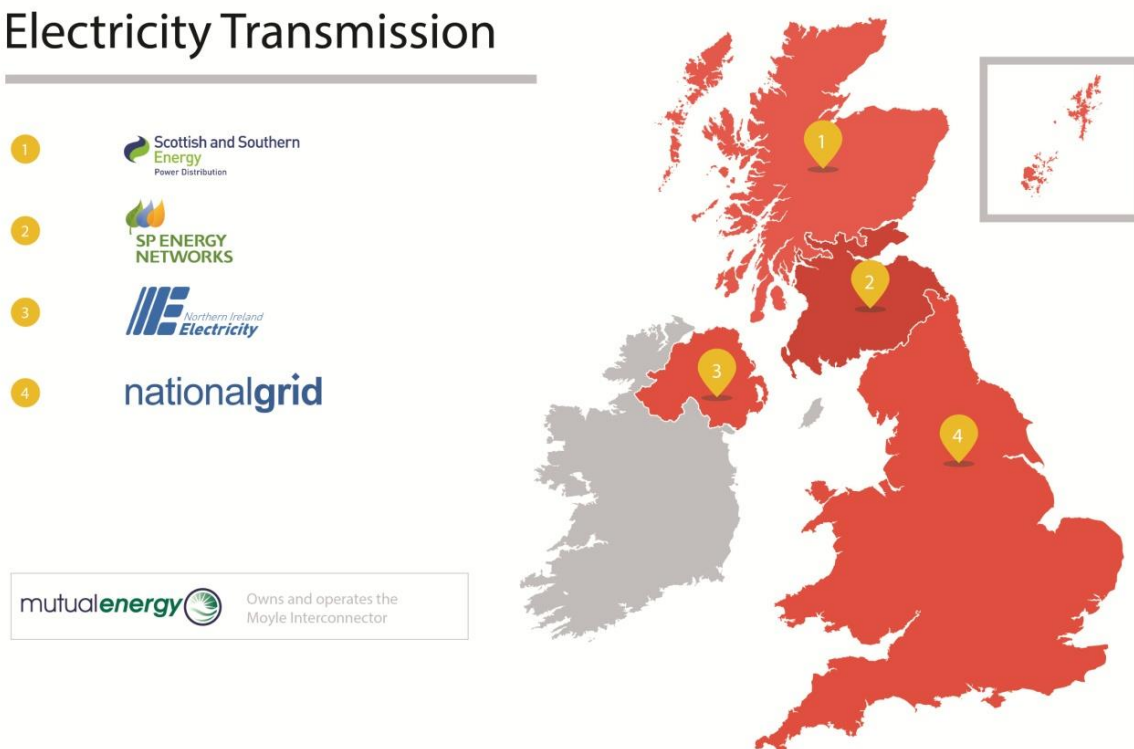


Figure 89: Regional electricity transmission networks, responsible for high-voltage connections to distribution facilities (Energy Networks Association, 2015).

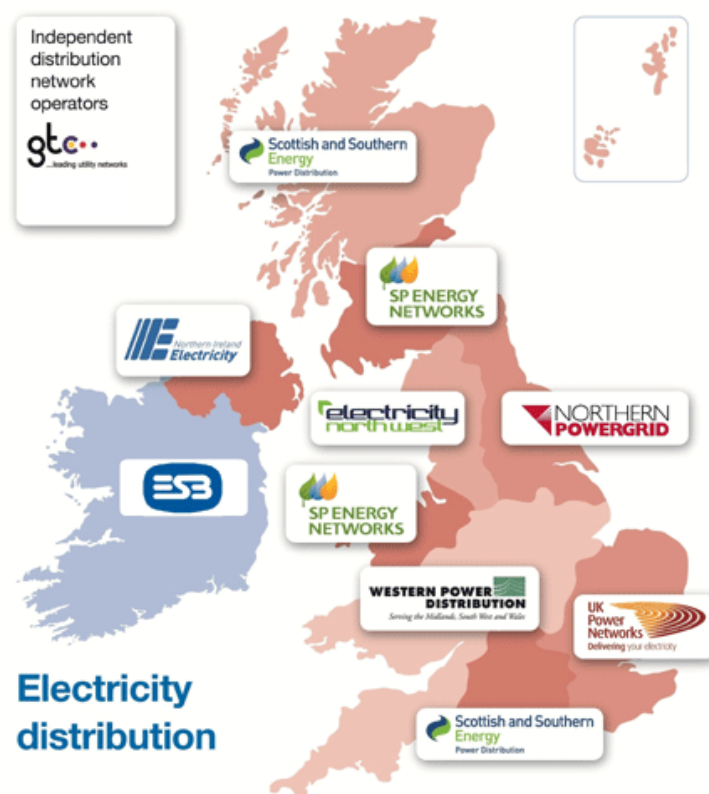


Figure 90: Regional electricity distribution network operators, responsible for low-voltage connections to residential, commercial and industrial consumers (National Grid, 2015)

The interaction of the different electricity markets can be condensed into the electricity price to the consumer. This is generally composed of 45-55% wholesale market costs, 20-25% network costs, 15-20% retail market costs (including profit), and approximately 15% of costs from "social and environmental policies" (Competition & Markets Authority, 2015).

10.3 Energy Resources and Trade

Fossil Fuels

The UK's indigenous resources of fossil fuels are dominated by oil reserves. In 2014 crude oil reserves were estimated at 3,100 million barrels (R/P of 5.5-9.8 years), coal reserves at 228 million tonnes (R/P of 20 years), and natural gas reserves at 253 bcm (R/P of 5.33-6.6 years) (World Energy Council, 2015; BP, 2015).

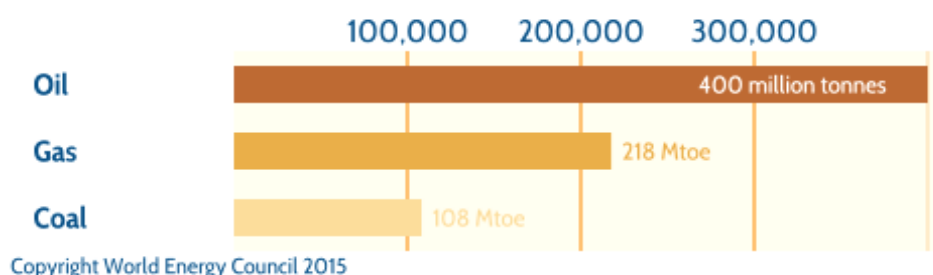


Figure 91: Fossil fuel reserves in the UK as estimated by (World Energy Council, 2015); the underlying dataset is from 2011.

Interconnection

To date the UK operates 4 standing electric interconnectors of a combined capacity of 4 GW. The connection to France (IFA) is 2 GW, to the Netherlands (BitNed) 1 GW, to Northern Ireland (Moyle) 500 MW, and to the Republic of Ireland (East West) also 500 MW. New interconnection capacity is being planned or currently under discussion with several other European countries such as Belgium, Denmark, France, Germany, Iceland, Ireland, the Netherlands, Norway, Spain, and Sweden (Department of Energy & Climate Change, 2013).

The importance of interconnection for the UK, as opposed for a country like Germany for example, is becoming more important with an increasing penetration of intermittent electricity generation. Intermittent generation requires balancing ability of the other power generators, energy storage technologies, and the electric network. Figure 92 visualises the history of the UK's net electricity import as proportion of primary energy supply. The share of electricity from interconnectors of total electricity supply in 2013 accounted for approximately 5% (Department of Energy & Climate Change, 2015).



Table 29: Summary of existing interconnections capacities

Name	Country	Capacity
IFA	France	2 GW
BitNed	The Netherlands	1 GW
Moyle	Northern Ireland	500 MW
East West	Republic of Ireland	500 MW

Figure 92: Electric interconnection from UK to other European countries (The Guardian, 2012).

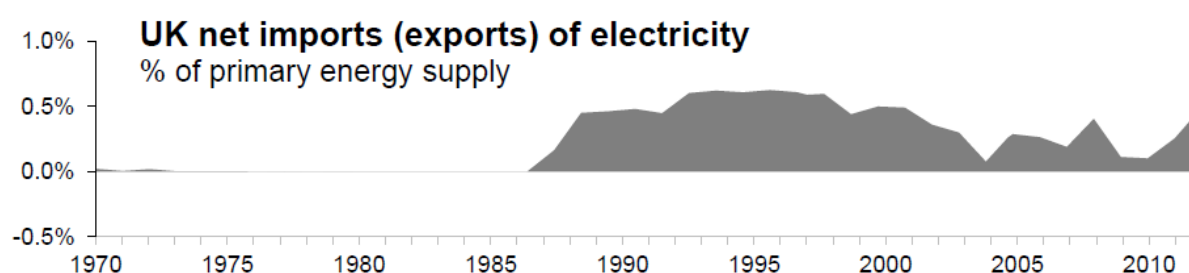


Figure 93: Net import of electricity as share of primary energy supply (Bolton, 2013).

Renewables

In recent years the UK has been focussing on expanding renewable electricity capacity. The share of electricity supply from renewables in 2005 was only 1% but in 2014 wind, solar, and other renewables accounted for 15% of the mix (Department of Energy & Climate Change, 2015). Figure 94 shows the current installed renewable power plant capacity in the UK.

The potential for renewable energy deployment in the UK, especially for wind power, is greater than in most other European. The capacity factor describes the fraction of firm capacity of the total amount of installed capacity. It is therefore an important measure to indicate the potential of an intermittent renewable technology to substitute firm, conventional power generators such as thermal power plants. The wind capacity factors for the UK range at 28 % for onshore and at 42% for offshore regions in the North Sea. This compares to a relatively low potential of less than 20% in central European countries (Staffell, 2014).

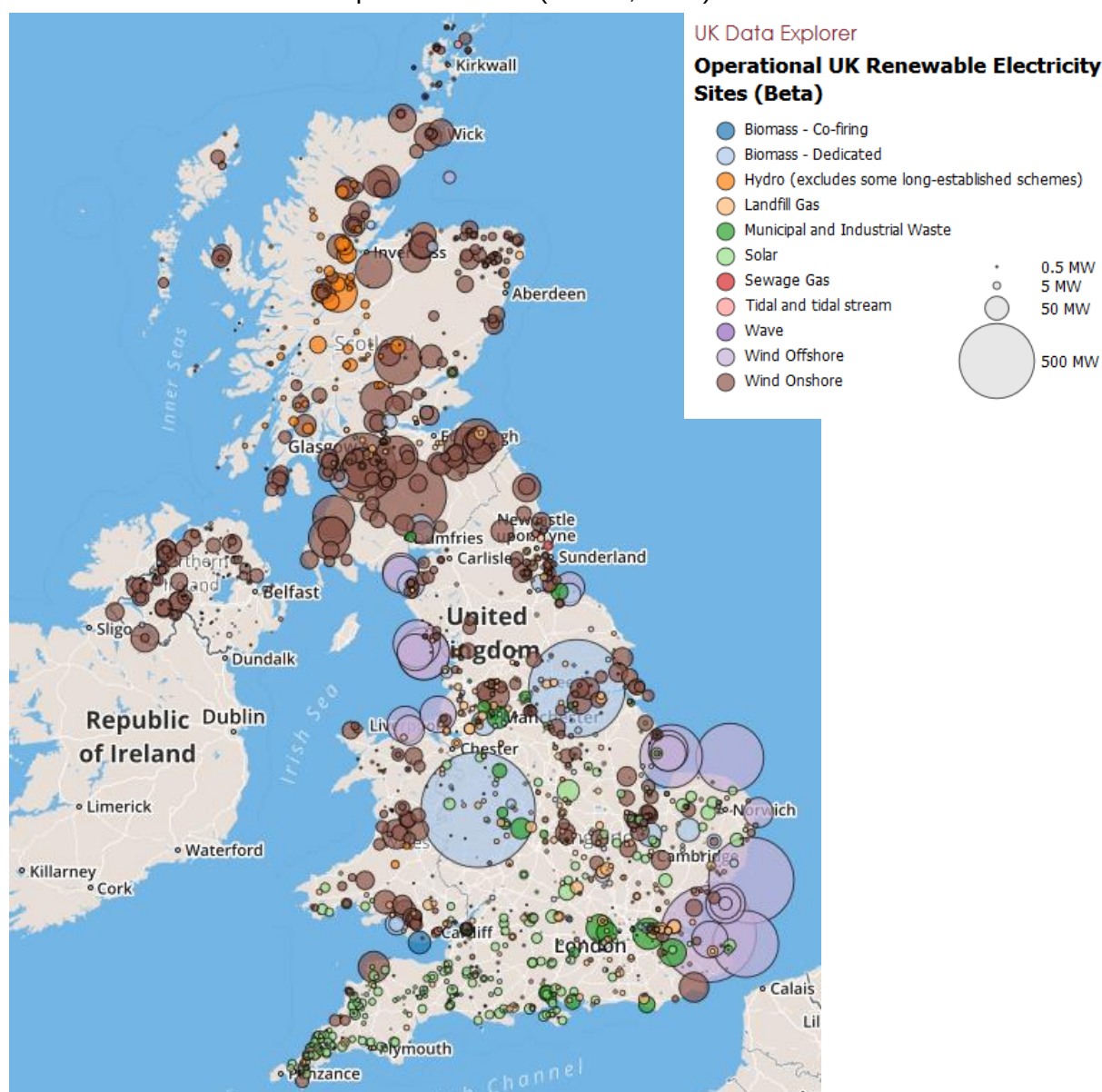


Figure 94: Installed renewable electricity capacity as of March 2014 from (UK Data Explorer, 2015) using RESTATS data.

The theoretical hydro potential of the UK is estimated at 4 TWh/year (World Energy Council, 2013). Most large-scale hydro power plants are located in Scotland. The total installed hydro capacity at the moment reaches 4 GW and pumped storage power plants accounted for 2% of electricity supplied in 2014 (Department of Energy & Climate Change, 2015).

10.4 Energy Policy and Drivers

In recent years, UK energy policy has found itself between the poles of reducing emissions, keeping energy affordable, and ensuring security of supply. A number of energy bills have been passed which aim at reducing greenhouse gas emissions in electricity production as well as in transportation, heating and buildings.

As the driver for energy policies in previous years has been to increase privatisation and competitiveness of the market, policies today are also motivated by the long-term desire to decarbonise the energy sector. Various support mechanism aim at increasing the use of low-carbon technologies. At the same time, the electricity market is extended and reformed to stimulate foreign and private investment. The aim of an increased energy independence is pursued by domestic oil and gas exploration and production. The existing policy mix in the UK is summarised in Table 30 and described in more detail thereafter.

Table 30: Major existing and planned policies relating to the electricity sector in the UK. Table adapted from (Renewable Energy Directive, 2010).

Policy	Type	Expected Result	Target Group	Time Horizon
Renewable Obligation (RO)	Regulatory	Increase electricity generation from various renewable energy sources	Large-scale operators	2002-2037
Feed in Tariffs (FITs)¹	Financial	Incentivise low-carbon electricity generation	Small-scale operators	2010-2021
European Investment Bank (EIB)	Financial	Provision of £700 million support for onshore wind power projects	Operators	To be determined
Green Investment Bank (GIB)	Financial	Provision of £3.8 billion funding for renewable energy and waste-handling projects	Developers of renewable energy generation	To be determined
Energy Market Reform (EMR)	Regulatory and Financial	Reduction of carbon emissions through incentives for low-carbon electricity, and efficiency measures while considering security of supply	Operators and investors	2011-beyond 2020
CCS demonstration programme	Financial	Support of CCS commercial-scale project (£1 billion), and technology innovation (£125 million)	Large-scale investment, research	2011-2015

¹ The Feed in Tariffs are further addressed and adjusted in parallel/subsequent policies such as the RO and the EMR.

Renewable Obligation 2002

England, Wales, and Scotland (in 2002), and Northern Ireland (in 2005) implemented the Renewable Obligation (RO) policy. The support through Feed in Tariffs (FiT) aims at small-scale and large-scale projects for renewable electricity. However, the support for large-scale photovoltaic (PV) and onshore wind projects (> 5 MW) closed in 2015. The FiTs are index-linked payments in £/MWh of renewable electricity fed into the electric grid. Tariffs differentiate between generation technologies and have been declining continuously for example £8.67/MWh² for PV power plants (of 50 - 100 kW size), or £13.73/MWh for wind power plants (15 - 100 kW) in the period from October to December 2015 (Office of Gas and Electricity Markets, 2015).

Another mechanism of the RO policy is the introduction of Renewable Obligation Certificates (ROCs), which are issued for the electricity generated from eligible renewable sources. In order to meet the required number of ROCs, operators can trade the "green certificates" or pay into a "buy-out fund" (Office of Gas and Electricity Markets, 2015). In the period of 2013/2014 the ROCs ranged at £42/MWh (Non-Fossil Purchasing Agency Limited, 2015). In March 2017 the RO program will terminate, however, accredited support will continue until 2037 (Office of Gas and Electricity Markets, 2015).

National Renewable Energy Action Plan

The National Renewable Energy Action Plan (NREAP) was implemented in 2010 as a fulfilment of the European Union directive 2009/18/EC. It outlines the UK's roadmap to achieve the committed EU 2020 targets of 20% renewable energy. As a compilation of the UK's policies it is therefore not listed as a single measure in Table 30.

The NREAP strategy sets to achieve 15% of energy coming from renewable sources by 2020. Energy in 2005 came only to 1.5% from renewable sources. For the electricity sector this is estimated to require 30% of renewable power in the mix. Heating is supposed to include 12%, transport 10% of renewable energy (Renewable Energy Directive, 2010). In the NREAP report, the UK indicates ambitions to "go a lot further" than the EU directive induces. With "greater leadership in tackling international climate change" the UK is trying to advance the EU targets from a 20% to a 30% emission reduction by 2020 (Renewable Energy Directive, 2010).

Electricity Market Reform 2011

Led by the conservative party since 2010, energy policy has taken a different direction. The 2011 Electricity Market Reform (EMR) sets out five main plans of action (Department of Energy & Climate Change, 2012).

² This value refers to the "middle rate" price level which is paid to operators who own at least 25 registered PV power plants. The "lower rate" for October to December 2015 ranges at £-p5.94/MWh and is paid if the PV system powers a building or does not suffice the efficiency standard (A-D) (Office of Gas and Electricity Markets, 2015). The "higher rate" of at £-p9.63/MWh is paid in every other case.

1. The establishment of a carbon price floor was initially legislated in the Financing Act 2011. The target price floor for 2020 is £30, £70 per tCO₂ in 2030.
2. The 'Contract for Difference' (CfD) and 'Feed in Tariff' (FiT) scheme incentivises investment for low carbon electricity generating technologies. Important here is the technology neutrality, hence CfD and FiT support intermittent renewables just as new nuclear power plants (Massachusetts Institute of Technology, 2011). The CfD aims at levelling out the volatility in electricity prices to an even strike price as to increase investment security. Initially technologies will be assigned different strike prices, eventually all low carbon electricity generators will compete at one level.
3. The introduction of a capacity market broadens the UK's trading portfolio. Capacity provider can compete centrally for annual contracts with steady payments several year in advance. This new framework supports also energy storage technologies and demand side management. Additionally, it highlights the increasing importance for reserve capacity to ensure supply reliability.
4. The 'Emissions Performance Standard' (EPS) regulates emissions caused by fossil fuelled power generators. The initial standard is set to 450 gCO₂/kWh of electricity generated. Ultimately, this scheme can force unabated coal generators to cease work or to implement CCS technologies (Platchkov, 2011).

The EMR directives are planned to be implemented in a four stage approach (Department of Energy & Climate Change, 2012).

Stage 1 → to 2017: CfD, capacity auctions subject to security of supply

Stage 2 → to 2020: Technology-specific auctions, capacity market

Stage 3 → 2020s: Technology-neutral auctions, demand side, storage, and interconnection as important role in balancing

Stage 4 → beyond: High carbon price, generators compete equally and fairly "without intervention" (Department of Energy & Climate Change, 2012)

The Department of Energy and Climate Change states to evaluate the key parameters in close collaboration with the system operator National Grid. DECC also indicated that with EMR coming in force "electricity prices are estimated to be, on average, 4% lower over the next two decades than they would otherwise have been" (Department of Energy & Climate Change, 2012).

CCS Programme 2011

Fossil fuels are to remain an important source of supply in the UK's energy mix. Carbon Capture and Storage (CCS) is seen to be the only option to reduce carbon emissions whilst continuing to use fossil fuels as established, yet reliable energy provider. Additionally, for the UK CCS has been identified as the cheapest option to reduce the system's carbon intensity (Edenhofer, 2014; Low Carbon Innovation Coordination Group, 2012; Energy Technology Institute LLP, 2015b).

From 2011 to 2015 the UK ran a CCS development programme to promote a CCS industry. As part of this, the government launched a "commercialisation competition" for large-scale CCS projects. The winner is being supported with a £1 billion fund; whereas the competition aims at leading to an overall promotion in commercial CCS development. Additional parts of the CCS program are a 4-year research and innovation fund of £125 million, as well as the organised collaboration with the Energy Industry Council aiming to drive supply chain project forward (Department of Energy & Climate Change, 2015c).

Current UK Energy Politics

The conservatives manifesto states to "not support additional distorting and expensive power sector targets" (Conservatives, 2015). The subsidies for on-shore wind power projects are ending in April 2016, one year earlier than planned. At the same time, the current government is open towards the build of new nuclear power stations.

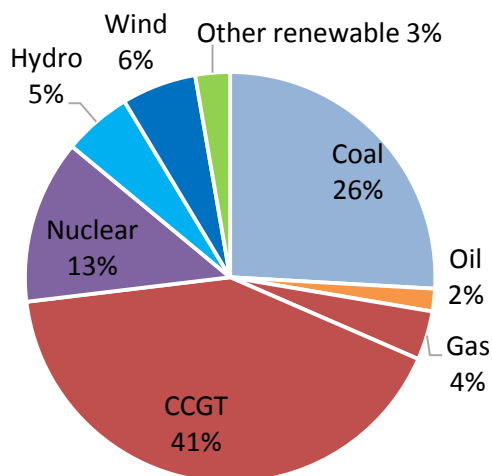
The Infrastructure Act from February 2015 covers in part energy related issues on transport, heating, and petroleum and geothermal energy. It sets out a plan to assess the compatibility of the carbon targets with the extraction and production of shale gas in the UK. Although the act aims at "maximising economic recovery of UK petroleum", it additionally outlines safety measures for hydraulic fracturing in the UK (Parliament of the United Kingdom, 2015).

Also in February 2015, the party leaders have signed a joint climate pledge. Herein government and opposition affirm to strive for a "legally binding, global climate deal" in order to keep the 2 °C target within reach (Green Alliance, 2015). Furthermore, it manifests a cross-party agreement on keeping the carbon budgets of the Climate Change Act as well as the transition to a low-carbon economy and the fade out of unabated coal power generation.

10.5 Generation Capacity

The current total of electricity generation capacity is summarised in Figure 95. It is dominated by gas-fired power stations, however, electricity production is equally split among these two energy sources. Production from renewables accounts for 16 % of the total in 2014, combining wind, hydro, and other thermal renewables such as power generation from bioenergy and waste. Nuclear power plants provided 21 % of electricity demand which equals just above 63 TWh of total 339 TWh in 2014 (Department of Energy & Climate Change, 2015).

Installed capacity by fuel in 2014



Electricity production by fuel in 2014

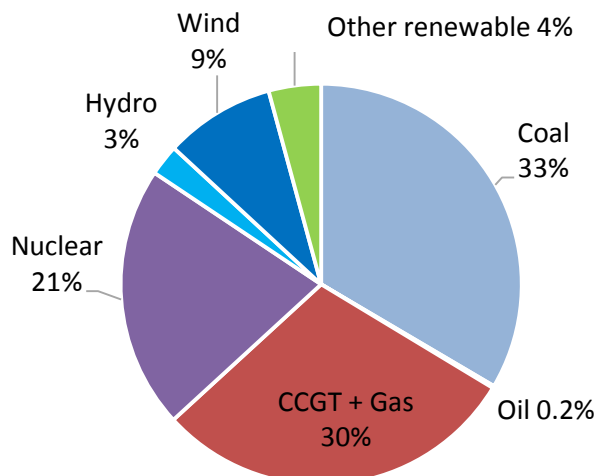


Figure 95: Installed electricity generation capacity and electricity production by fuel in 2014 (Department of Energy & Climate Change, 2015).

Net electricity supplied from all electricity generating companies in the UK totalled 318 TWh. Combined with the net import of 20 TWh a total of 338 TWh was available. 303 TWh of electricity were actually consumed in 2014; the difference in available electricity and consumed electricity made up for losses due to distribution and transmission, as well as losses on the end-user side.

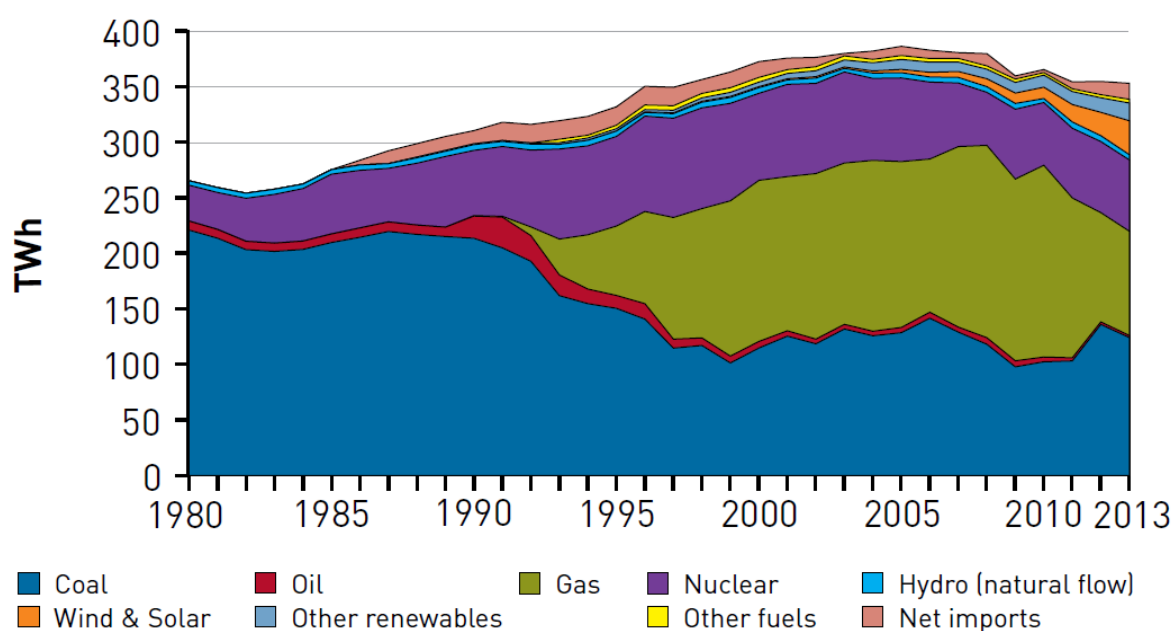


Figure 96: Electricity generation by fuel type from 1980 to 2012 (Department of Energy & Climate Change, 2014).

Historically, electricity generation in the UK has been led by coal and nuclear power. Since the 1990s gas-fired power stations, especially CCGTs due to their high efficiency, have become a major component in the electricity mix. Only within the past five years, renewable electricity generation is becoming to meet a considerable proportion (16 % in 2014) of electricity demand. In comparison, the proportion of low-carbon energy (including energy from nuclear power stations and fuels for transport) in the UK was the 10th lowest among the EU countries (Department of Energy & Climate Change, 2014).

10.6 Discussion and Analysis

Major changes in the UK's energy system are necessary in order to reduce carbon-intensive power generation. The policies in place, such as the EMR, do focus on incentivising low-carbon generation. However, if the mix of regulations will lead to compliance with the climate targets remains to be seen.

The following section deals with projected estimates for the future electricity sector. Government institutions as well as major national and international research institutions have released a number of scenarios for future electricity generation capacity and production in the UK. As benchmark, the reference scenario by DECC will be looked at more closely. The ensuing section compares a range of scenarios in the threefold categorisation of “Intermittent Renewables”, “Firm Low-Carbon”, and “Fossil Fuel and CCS” (FF/CCS) power technologies.

Capacity Targets

The reference scenario published by DECC published in September 2014 reveals a significant build-up of electricity generating capacity for the next three decades. Figure 97 visualises an increase of power supply related asset base to 40%, from 103 GW in 2014 to 142 GW in 2035. This is due to an expected increase in electricity demand of approximately 22% from 2014 to 2035 (Department of Energy & Climate Change, 2014).

Another reason for the growing total installed capacity is the changing mix of generating technologies. Different types of generating technologies have different characteristics in terms of their efficiency, their carbon intensity, or their availability for instance. One important feature is the capacity credit, which refers to the percentage of firm, or reliably available capacity of the net installed capacity of the respective type of technology. In general, the capacity credit for conventional thermal power plants is 100%, given the permanent availability of fuel and capability of operation. The capacity credit of intermittent power generators is significantly less as it depends on the external availability of the renewable source, such as wind or solar irradiation. The annual average capacity credit for wind power stations in the UK is close to 28% for on-shore and 42% for off-shore regions of the North Sea (Staffell, 2014; Holttinen, 2013).

In consequence, a large build-up of intermittent generation capacity can substitute conventional technologies only to a certain extent, respectively according to the capacity credit of the technology. As the proportion of wind power capacity (in figure 97 as part of “Renewables”) increases considerably (nearly doubles from 2014 to 2035), conventional thermal capacity together with interconnectors and storage remain to account for 55% of the asset base.

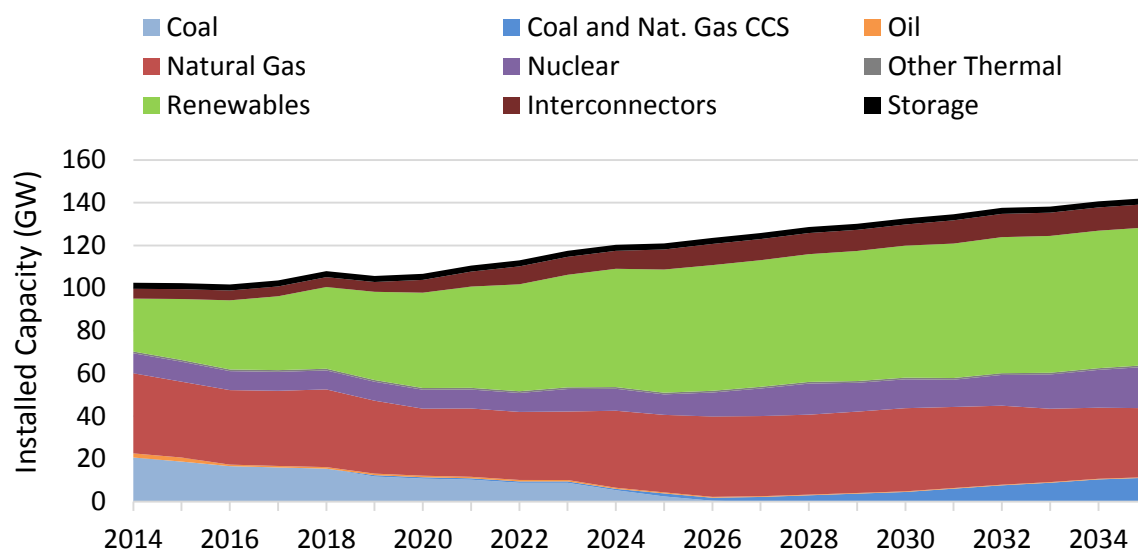


Figure 97: Installed electricity generating capacity in the reference scenario of DECC (Department of Energy & Climate Change, 2014). This scenario is based on the central growth and fuel price estimates and considers existing and designed energy policies.

Further implications of the changing mix of power generating capacity such as a decrease in utilisation of thermal power stations and an increased cycling and operation off the nominal point due to balancing issues exceeds the scope of this study. A starting point for further studies and material on these topics can be found in (Gross, 2006; National Renewable Energy Laboratory, 2013; Energy Research Partnership, 2015b).

10.6.1 Future Scenarios and Projections

The rate of change in the UK's mix of electricity generation is expected to increase significantly over the next decades. Coming from a fossil dominated system, the UK has started moving towards low-carbon energy sources. Figure 98 presents a range of scenarios for a time horizon between 2010 and 2050. The historic data for 1960 to 2010 is taken from the IEA's energy statistics (International Energy Agency, 2015).

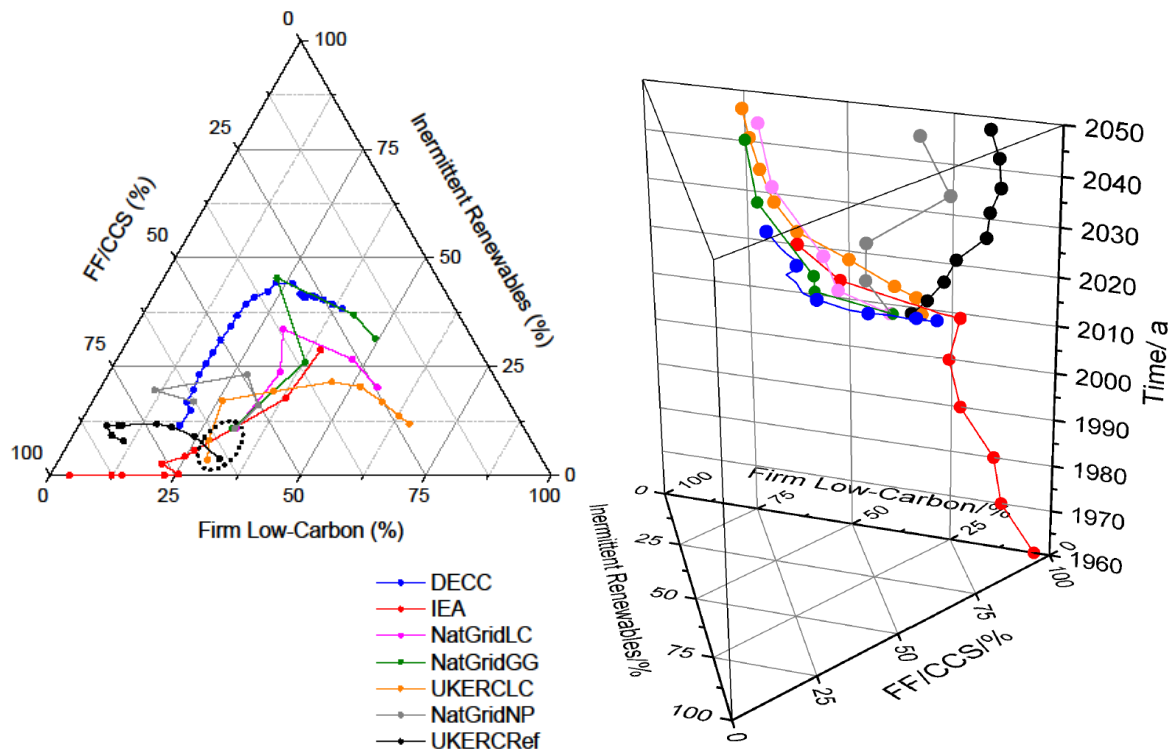


Figure 98: Electricity generation scenarios for the UK up to 2050 (Department of Energy & Climate Change, 2014; National Grid, 2014; UK Energy Research Centre, 2013; International Energy Agency, 2015). The abbreviation "FF/CCS" here refers to fossil fuel based and CCS combined power stations

There are two main branches visible in the set of trajectories. The one, leading on a path of high shares of intermittent renewable energy sources, reaching close to 45% in 2025 as the reference scenario presented by DECC indicates (Department of Energy & Climate Change, 2014). Other publications, such as the National Grid's "Gone Green" (NatGridGG) and "Low Carbon" (NatGridLC) scenario, as well as the UK Energy Research Centre's (UKERC's) "Low Carbon" (UKERCCLC) and IEA data (IEA) are following this trend line. The second branch, represents a business-as-usual case where electricity demand remains to be met by fossil energy sources. This possible path is National Grid's "No Progression" (NatGridNP) and the UKERC's reference scenario (UKERCRef).

In the set of scenarios presenting the low-carbon transition, all references indicate a fade out unabated coal-fired capacity between 2027 and 2035. This is in compliance with the recent joint climate pledge signed by the current leaders of the major political parties in the UK, who agreed to focus on decommissioning unabated coal-fired power stations. At the same time, CCS technology is beginning to be deployed in combination with coal and natural gas power stations, accounting for 8 - 9% in the estimated capacity mix of 2035 for DECC's, UKERC's low-carbon, and National Grid's low-carbon scenario. In the other scenarios CCS is either not explicitly listed or not deployed.

As the Electricity Market Reform induces, all carbon intensive power generators are reduced or fade out entirely from the future mix of technologies. Conversely, nuclear and renewable

energy capacity increases by 50%, and respectively 88% according to DECC's reference scenario. The projected electricity system of 2035 would then indeed consist of 70% low-carbon power generators, the other 30% coming from natural gas power stations and interconnectors. These numbers indeed indicate compliance of the political plan and the projected electricity system of 2035. However, it remains to be seen whether action will follow these plans.

10.7 Summary

The UK is the only country analysed in this report with a long term energy transition plan to 2050. The energy mix today is still dominated by fossil fuels, however, ambitions to move to a low-carbon system are evident. A political promotion of low-carbon power generators through the Electricity Market Reform (EMR) highlights an environmentally and economically driven approach. The EMR tries to tackle the emission reduction targets by considering the power generating mix of capacities and subsidising low-carbon technologies with the Contract for Difference (CfDs) and Feed in Tariffs (FiTs) schemes. Emission regulations for fossil fuel power plants underline the climate focus. Simultaneously, the introduction of a capacity market emphasises the concern on security of electricity supply and a reliable system coping with a greater share of intermittent power generators.

However, the implemented policies have also led to disorientation about the strategic direction as well as the eligibility of support. For example, the uncertainty in the level of CfDs has yet delayed investment decisions, although a support for investment is exactly the purpose of this measures. Similarly, the auctions in the newly introduced capacity market are set for a yet unspecified time scale.

Also previously implemented policies, such as the Renewable Obligation (RO) in 2002, lack the possibility for foresight and long-term planning. Initially, RO was providing support for various renewable power generators. However, in July 2015 the ending of the support for small-scale PV (< 5 MG) as of April 2016 is causing confusion and frustration to PV operators. Additionally, the prices of the Renewable Obligation Certificates (ROCs) are released only one year ahead of time such that the decision for power plant operators between investment, trade, or buy-out has little lead time. However, in 2027 DECC is planning to fix ROC prices for the final ten years up to 2037 (Department of Energy & Climate Change, 2015b). Recent UK energy politics have changed direction, ending on-shore wind power support and announced the promotion of research and development in shale gas fracturing.

Other existing energy policies such as the support for renewable energy projects through the European Investment Bank (EIB) and the Green Investment Bank (GIB) have an economical character in their way of stimulating investment in low-carbon power generation and research. In combination with the government's affirmation of following the most cost-effective path and minimising energy cost, this could create the appearance of an economic driven policy-making rather than one sincerely aiming at mitigating anthropogenic climate change.

According to energy transition scenarios from DECC, the National Grid, and other UK research organisations, the UK's mix is likely to develop in the direction that policies are aiming for. The environmentally optimistic scenarios, which are however compliant with existing policies, all include a significant amount of intermittent renewable energy sources, mainly wind power, as well as gas and nuclear power plants by 2030, respectively 2050. An electricity system dominated by low-carbon power generators seems within the realms of possibility.

It is evident that UK energy politics are holding on to its long-term carbon targets of 34% reduction of total carbon emissions by 2030, respectively 80% reduction by 2050. Across the different parties and positions, the overarching direction is meant to remain consistent. Policies in place aim at ultimately providing a technology-neutral support to all types of low-carbon power generation as to create equal and market-driven playing field. However, this indiscriminative approach might be ineffective at first and more political guidance and coherency necessary.

Unlike other developing or low-income countries the UK has financial resources and regulatory power to support and push the energy industry in a low-carbon direction. Efforts are being made in politics, industry, and research. The problem remains within the trilemma of carbon avoidance, cost, and the security of electricity supply. The future will show which side of the triangle will outweigh the others or if a stable balance is possible.

11 Discussion and Conclusions

This report examined how the electricity systems in Australia, China, India, Malaysia, Singapore, South Africa and the UK are likely to change towards 2030 based on current installed capacity, planned capacity, and policy trends. Furthermore, likely consequences of these trends on sectoral emission was determined. This country-level analysis of the power sector has allowed for the identification of several varying characteristics across country electricity systems. For one, climate change mitigation does not seem to be the main policy driver in any of the countries examined. There is an emphasis on stimulating economic growth, enhancing energy security and addressing constraints within the electricity system and supply. Furthermore, capacity expansion and transmission improvements through private sector investment seems to be encouraged in countries with state controlled systems. Additionally, capacity and generation targets in the countries examined do not extend beyond 2030. These main findings are explained below.

1. Emphasis on stimulating economic growth is evident in all countries.

- **Australia's** Energy White Paper calls for ensuring the nation's international competitiveness in the global energy economy and to provide affordable energy to domestic consumers in order to promote economic growth. This seems to have had implications on Australia's climate change policy, as the nation's climate change legislation was deemed to run contrary to these objectives.
- **China's** growth was seen to be hindered by energy dependence, resource constraints and an over-reliance on government-led investment. Its mitigation actions and targets are primarily driven by these domestic considerations and the need to reduce local environmental degradation.
- **India's** 12th Five-Year Plan called for faster, sustainable, and more inclusive growth. Their economic objectives are focused on increasing the annual GDP growth rate in order to provide access to electricity for the remaining 25% of the population that currently does not have access.
- **Malaysia** aims to reach high-income status by 2020, which caused it to initiate programmes such as the development corridors (eg SCORE) and the Economic Transformation Programme (ETP). These both have an emphasis on the energy sector with the oil and gas sectors are integral components in fostering Malaysia's economic growth.
- **Singapore** have been focusing on the promotion of a fully competitive market and the National Energy Policy report provided a framework for continuing their economic growth whilst improving energy security and diversifying fuel supplies. Singapore is a major hub for oil and petroleum trade and has a significant refining capacity. The petrochemical industry is an important contributor to GDP and Singapore have strong ambitions to expand this.

- **South Africa's** economic growth is hindered by electricity supply shortages. Addressing this issue is key to the National Development Plan goal to reduce income inequality and eradicate poverty.

2. Energy security concerns promote the diversification of the electricity mix.

- **China** is a net importer of coal, natural gas and oil. There is also a geographical mismatch between where its unexploited reserves are located and the major energy demand centres in the eastern provinces. The government is investing in infrastructure to address bottlenecks in the transportation of coal, as well as diversifying its imports of natural gas by constructing pipelines and LNG terminals. Renewable energy generation is seen as a viable means to reduce reliance on foreign imports of fuel.
- **India** is becoming increasingly dependent on coal and natural gas imports as a result of insufficient domestic production and ever growing electricity demand. The government is expanding the LNG regasification terminals to secure natural gas from the global markets as well as placing ambitious targets for renewable energy deployment. There has been a nuclear programme in place for many years aiming to utilise India's abundant thorium reserves, but progress has been historically slow with this.
- The **Malaysian** government have been diversifying the generation capacity by increasing the proportion of coal fired power stations. Malaysia is promoting the use of other fuels in the electricity generation mix so that they can maintain their position as the world's second largest exporter of LNG. The expansion of hydropower is also an integral part of Malaysian energy policy in order to fully exploit domestic resources.
- **Singapore** are almost completely dependent on energy imports, particularly pipeline natural gas from Indonesia and Malaysia. The government has therefore have been focusing on diversifying their supply of natural gas through the building of LNG terminals. There has also been the introduction of a clean coal and biomass cogeneration plant which indicates that the government are considering other fuels to diversify the power sector.

3. A key driver of capacity expansion and improvement is the need to address shortages in electricity supply.

- **China** expects electricity demand to continue growing towards 2020. It is investing in new power generating capacity in order to prevent shortages. Whereas India is promoting primarily fossil fuels, China is promoting a more diversified electricity mix due to concerns regarding air quality and environmental degradation.
- **India** has one of the highest T&D losses in the world and has frequent blackouts due to lack of capacity to meet peak electricity demand. India's continued effort to integrate its regional transmission grids is an attempt to improve the reliability and flexibility of its grid. Furthermore, India's coal-fired capacity targets reflect its ambition to increase generating capacity in the most cost-effective manner. Furthermore, India's ambitious

plan to expand hydropower capacity in its northern states is a reflection of its need to increase its peak power capacity.

- **South Africa** is facing an electricity crisis, as unplanned outages at Eskom's ageing power fleet has caused production to decline and led to widespread blackouts. This has had significant effect on South Africa's economic growth, and businesses and households across the country have bought diesel and petrol generators to power their facilities during outages. South Africa's capacity targets, as outlined in its Integrated Resource Plan, are intended to alleviate pressures on the grid. As coal-fired generation is relatively cost-competitive, it is likely to increase.

4. In countries with large state-owned electricity actors, private sector investment is seen as key to diversifying the electricity mix and stimulating infrastructure enhancements.

- As the **Chinese** government shifts away from a government-led investment model, it envisages a greater role of private sector investment in the electricity sector. The government also intends to restructure state-owned enterprises in the sector in order to make them more efficient.
- In **India**, the state-owned generating companies continue to miss government targets for installed capacity additions. Private sector investment is seen as necessary to increase capacity and improve existing transmission infrastructure.
- As state-owned Eskom is facing financial difficulties, private sector investment in the **South African** electricity sector is seen as a way to enhance generation capacity and diversify supply. To this end, the government has mandated that 30% of all new generation capacity should be constructed by Independent Power Producers. It has launched several private sector procurement programmes to increase investment in renewable energy sources, gas-fired generation, and coal-fired capacity.
- The **UKs** electricity market has been extended and reformed to stimulate foreign and private investment.

5. There is a lack of long-term planning beyond 2030 in the electricity sector in the countries examined.

- The only generation target that is in place in **Australia** is the target set by the RET to increase the share of renewable energy generation to 20% by 2020. The RET does not specify which renewable energy sources should be installed, however, making it likely that that new generation will be dominated by the most cost-competitive technology. Furthermore, the current policy climate makes it unlikely that the RET is extended or even replaced by further targets regarding the expansion of low-carbon generation. Neither the government nor the market operator have detailed targets regarding what sources should be used to generate electricity in upcoming years. This lack of long-term planning combined with the lack of incentives is likely to cause an increase in coal-fired capacity.

- **China** has detailed installed capacity targets for renewable energy sources in place towards 2020. China does not, however, outline its intended installed capacity for thermal generation sources. It is likely that these will be published in its 13th Five Year Plan in October 2015, as previous FYP's have outlined installed capacity targets.
- **India** have targets for capacity expansions up to 2022 although multiple contrasting ambitions exist. The five year plans outline capacity targets along with scenarios developed by the Central Electricity Authority. The Ministry of New and Renewable Energy also outline the renewable capacity targets and these are much more ambitious than other government targets that have been outlined. The lack of coordination between government ministries is evident and leads to an uncertain environment for investors. This is further enhanced by the lack of long term planning in the power sector.
- Capacity expansion plans in **Malaysia** only exist up to 2025. Differing capacity targets exist for the three regions of Malaysia and there seems to be a lack of coordination between states. The huge expansion of generating capacity in the eastern state of Sarawak is based upon an interconnector being built to export electricity to Peninsular Malaysia. The project has been continuously delayed leading to large overcapacity in the electricity system of Sarawak, whilst the majority of demand increases are in Peninsular Malaysia.
- **Singapore** have limited targets for generation expansion due to the current overcapacity in the system. A solar energy target exists for 2020 but beyond this, the ambitions for the power sector are unclear although the potential benefits and CO₂ savings from further solar deployment have been outlined.
- **South Africa's** Integrated Resource Plan outlines capacity targets towards 2030. This plan is supposed to be updated every two years to reflect developments in the electricity sector. The approval process of the latest update, however, has faced delays, and so investment decisions are still based on the original IRP 2010.
- The **UK** is the only country analysed with a long term energy transition plan towards 2050. The legally binding Climate Change Act in 2008 set the strict target to reduce carbon emissions by 80% of 1990 levels by 2050. Nevertheless, there is a change of direction from the current government with the subsidy cuts for small-scale solar PV and onshore-wind. Additional uncertainties and inconsistencies in existing regulations have delayed new investment in the energy sector and could have a detrimental impact on the move towards the 2050 goal.

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