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International Renewable Energy Agency

SMART ELECTRIFICATION WITH RENEWABLES

Driving the transformation of energy services

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About IRENA

The International Renewable Energy Agency (IRENA) is an intergovernmental organisation that supports countries in their transition to a sustainable energy future, and serves as the principal platform for international co-operation, a centre of excellence, and a repository of policy, technology, resource and financial knowledge on renewable energy. IRENA promotes the widespread adoption and sustainable use of all forms of renewable energy, including bioenergy, geothermal, hydropower, ocean, solar and wind energy in the pursuit of sustainable development, energy access, energy security and low-carbon economic growth and prosperity. **www.irena.org**

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CONTENTS

FIGURES

TABLES

BOXES

ABBREVIATIONS

1.5-S	1.5°C Scenario
BES	Baseline Energy Scenario
BEV	Battery electric vehicle
CCS	Carbon capture and storage
CHP	Combined heat and power
CO_2	Carbon dioxide
CSP	Concentrating solar power
ERS	Electric road systems
EV	Electric vehicle
FCEV	Fuel cell electric vehicle
GDP	Gross domestic product
GHG	Greenhouse gas
HVDC	High-voltage direct current
IEA	International Energy Agency
ICT	Information and communication technology
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
LCOE	Levelised cost of electricity
LHV	Lower heating value
MENA	Middle East and North Africa
NA	Not applicable
OECD	Organisation for Economic Co-operation and Development
P2G	Power-to-gas
P2M	Power-to-methane
P2X	Power-to-X
PEM	Proton exchange membrane
PHEV	Plug-in hybrid electric vehicle
PtL	Power-to-liquids
PV	Photovoltaic
R&D	Research and development
RD&D	Research, development and demonstration
REmap	Renewable Energy Roadmap
SGERI	State Grid Energy Research Institute
T&D	Transmission and distribution
TES	Transforming Energy Scenario
TSO	Transmission system operator
VPP	Virtual power plant
VRE	Variable renewable energy
V2G	Vehicle-to-grid
ZEV	Zero emission vehicle

UNITS OF MEASURE

EJ	Exajoule
GJ	Gigajoule
Gt	Gigatonne
GW	Gigawatt
GWh	Gigawatt hour
GW-km	Gigawatt-kilometre
hr/yr	hours per year
kg	Kilogram
km	Kilometre
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt hour
m^2	Square metre
MW_e	Megawatt electric
MWh	Megawatt hour
Pj	Petajoule
t	tonne
t/yr	Tonnes per year
TW	Terawatt
TWh	Terawatt hour
yr	Year

ABOUT THIS REPORT

The latest work from the International Renewable Energy Agency (IRENA) shows that electrification is a top priority in the short and medium term to set the energy system on the path needed to keep the rise in global temperatures to well below 2°C. In IRENA's "World Energy Transitions Outlook" (2021) electricity consumption more than doubles to over 50% of global final energy consumption by 2050. This means electricity's growth as a share of total global final energy consumption must accelerate almost four or fivefold to about 1% each year, from relatively consistent historical levels averaging around 0.2-0.25% since 1980. This must begin as soon as possible, as every year the increase in electrification with renewables is delayed means an even greater acceleration is needed. If the world would like to hold the line at a 1.5°C temperature increase, then the pace of electrification with renewables must accelerate further still to meet additional clean electricity uses required by 2050.

IRENA has recently addressed a wide range of key topics related to the urgent drive toward greater electrification, as summarised in Box 1.

Crucially, this report has been jointly developed through a partnership with the China State Grid Energy Research Institute (SGERI). As such, it benefits from the perspective of the world's largest grid operator, and one that is strongly focused on the challenges and opportunities of rapid electrification, digitalisation and renewables deployment. Many of the critical innovations related to smart electrification with renewables are expanding at their fastest pace in China – for example in the electrification of transport – so their involvement in this work and in future discussions on the topic has the potential to provide invaluable lessons.

This report aims to consolidate IRENA's work in this area, and in doing so provide policy makers with a conceptual overview of the global transition to electrification with renewables. It presents recent trends in relevant technologies and innovations, sets out possible long-term pathways for electrification with renewables, and identifies priority actions to enable those pathways.

Throughout the paper, the underlying concern is how to achieve "**smart electrification with renewables**", rather than poorly planned electrification. Smart electrification with renewables focuses on the potential synergies between major increases in renewable power generation, electrification and digitalisation, and looks to create the conditions for the unprecedented co-ordination of their deployment and more efficient use across end-use sectors – power, transport, industry and buildings. To provide more insights into the strategies behind and benefits of such an approach, an extensive literature survey has also been performed as part of this study.

A summary of this report and its main findings is available in the publication "Electrification with Renewables: Driving the transformation of energy services – A Preview for Policy Makers" (IRENA, 2019a).

Box 1. IRENA work on electrification with renewables

In exploring the trends and possible long-term pathways for electrification with renewables, this report benefits significantly from a wide range of other existing and ongoing IRENA work on the subject. In the context of the complex and systematic transition toward smart electrification with renewables, the following publications act as helpful complements to this report, by providing rich detail on more specific elements:

- **Power system flexibility for the energy transition** (IRENA, 2018a): This report outlines a planning approach and a range of options to boost flexibility, specifically to accommodate the largest possible shares of variable renewable energy (VRE) sources (solar and wind).
- **Hydrogen from renewable power: Technology outlook for the energy transition** (IRENA, 2018b): This report studies the role of hydrogen, including the technical maturation and cost reductions needed to meet a range of energy needs that are difficult to address through direct electrification.
- **Innovation landscape for a renewable-powered future: Solutions to integrate renewables** (IRENA, 2019b): This major study identifies and analyses a suite of 30 innovations to integrate high shares of VRE into power systems across four key dimensions: enabling technologies; business models; market design; and system operation. As part of this work, dedicated briefs are also available for the innovations identified.
- **Hydrogen: A renewable energy perspective** (IRENA, 2019c): This paper examines the potential of hydrogen fuel to fulfil hard-to-decarbonise energy applications, including energy-intensive industries, trucks, aviation, shipping and heating.
- **Demand-side flexibility for power sector transformation: Analytical brief** (IRENA, 2019d): This brief maps out applications and examples of demand-side flexibility with different maturity levels and timescale impacts, including via electrified heat and transport.
- **Navigating the way to a renewable future: Solutions to decarbonise shipping** (IRENA, 2019e): This report explores the impact of maritime shipping on carbon dioxide (CO_2) emissions, the structure of the shipping sector and key areas that need to be addressed to reduce the sector's carbon footprint.
- **Innovation Outlook: Smart charging for electric vehicles** (IRENA, 2019f): This outlook shows how policy and technological breakthroughs can advance the development of smart charging technology for renewables.
- **Global Renewables Outlook: Energy Transformation 2050** (IRENA, 2020a): This comprehensive analysis outlines the investments and technologies needed to decarbonise the energy system in line with the Paris Agreement. It also explores deep decarbonisation options for challenging sectors, aiming to eventually cut CO_2 emissions to zero.
- **Rise of renewables in cities: Energy solutions for the urban future** (IRENA, 2020b): This report explores the rise of renewables in cities and the untapped opportunities for locally available renewable energy given the variety and maturity of technology applications in cities. It also examines the available modelling tools for urban energy system planning that can be used to identify feasible options.

- **Reaching zero with renewables: Eliminating CO_2 emissions in industry and transport** (IRENA, 2020c): This report explores how the world can achieve zero emissions by 2060, particularly by leveraging the power of renewables, and what technological, policy/regulatory and economic changes can enable it in main industrial and transport sectors.

In addition to this report and the work cited above, IRENA will be taking the topic of smart electrification forward with a new edition of its **Innovation landscape** series: "In**novation landscape for smart electrification of energy demand**". This report will delve deeper into the definition of smart electrification and how to anticipate bottlenecks in its deployment. It will provide an overview of systemic innovations to accelerate end-use electrification, as well as a toolbox to establish strategies for successful smart electrification.

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1 ELECTRIFICATION IN THE GLOBAL ENERGY TRANSITION

1.1 BASIC UNDERSTANDING OF ENERGY TRANSITIONS

Put simply, an energy transition represents a profound change in the energy system. It includes major changes in the supply of energy; in how energy is processed, converted, delivered and consumed; and in a wide variety of markets and policies. It also has important implications and effects that go far beyond the energy system itself, transforming many parts of the economy, society and environment. This section addresses three important observations:

(1) Energy transitions are highly complex.

Energy systems are both complex and highly integrated, making them difficult to change. The fossil fuel-based energy system, for example, has led to an enormous and entrenched web of intertwined infrastructure assets, policies, regulations and subsidies, from thousands of miles of pipelines to billions of cars, heating systems and other devices that run on fossil fuels. Transitioning from the current system thus requires massive changes, not just in technologies, but in policies and regulations as well. Making such changes, in turn, requires unprecedented amounts of political will, clear policy direction and national ambition. As a result, there may be significant differences in the extent and pace of the energy transition among different countries.

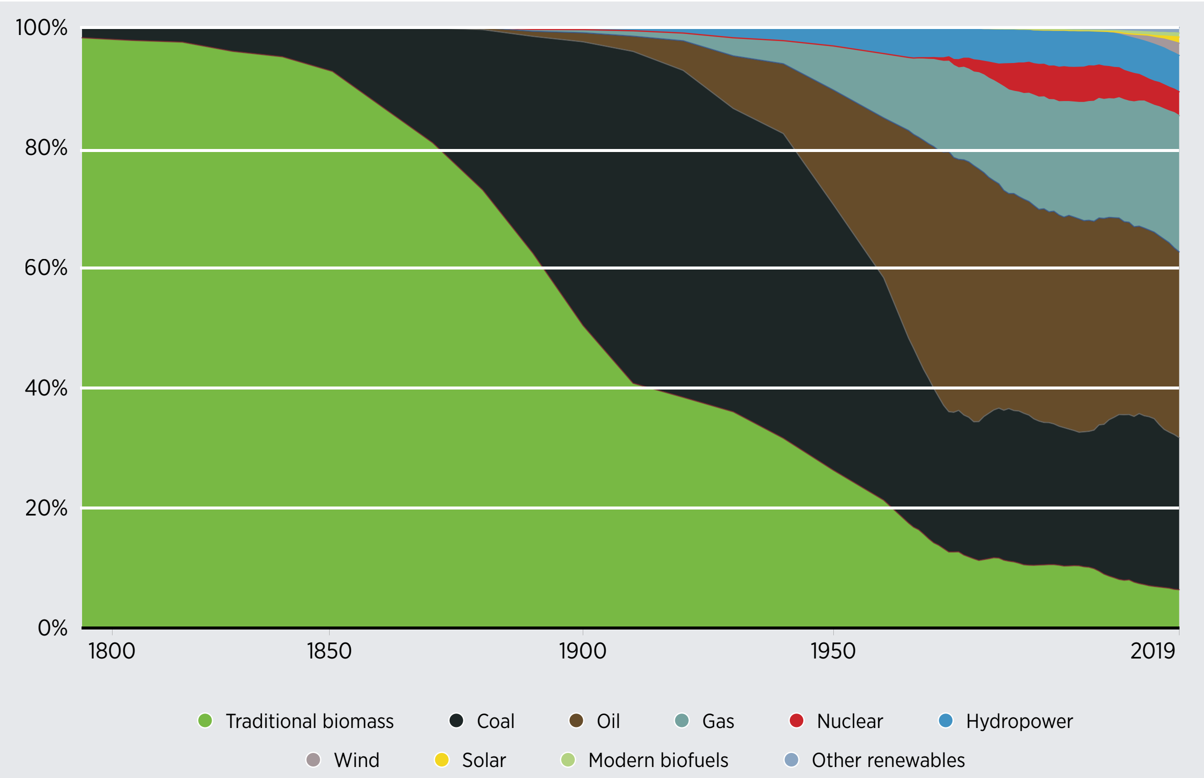
(2) The current energy transition must be faster than those in the past.

Due to their complexity, energy transitions are not necessarily easy or naturally quick processes; previous energy transitions took place over relatively long time periods. For example, it took roughly 70 years for the share of oil in the primary energy mix to rise from about 1% in 1890s to overtake coal as the predominant form of energy. Given the urgency of climate change, however, the next transition must be accomplished far more quickly than those of the past.

(3) Energy transitions require a systemic perspective.

The energy system includes the supply of energy, the consumption of energy, technologies to use energy, energy infrastructure and much more. An overall vision for the whole system is therefore required, rather than focusing just on isolated and fragmented elements, and the impact of non-energy systems must also be accounted for. Only through in-depth analysis of the relationships and mechanisms at work between these individual elements and in systems as a whole can we begin to understand the key characteristics of the next energy transition. At the same time, a truly systemic approach also goes beyond technology and infrastructure to include the policy, financial, regulatory and business model frameworks necessary to accelerate the transition. All elements emerge simultaneously and interact with each other.

Figure 1 Global primary energy consumption (1800-2019)



Note: In the figure above, primary energy is calculated according to the "substitution method", which takes account of the inefficiencies in fossil fuel production by converting non-fossil energy into the energy inputs required if they had the same conversion losses as fossil fuels.
Source: Our World in Data (2021).

1.2 THE DRIVING FORCES BEHIND THE CURRENT ENERGY TRANSITION

In the 21st century it has become increasingly clear around the world that the large-scale exploitation and use of fossil energy is causing serious problems, in particular climate change and ecological and environmental damage. At the same time, global innovation in energy science and technology has accelerated, making it possible to envision and create a new energy transition based on energy efficiency and renewable energy. These driving forces behind the current energy transition are discussed here:

(1) Climate change

Global climate change is now an indisputable fact, and the main cause is the emission of greenhouse gases into the atmosphere from human activity, predominantly the burning of fossil fuels. In 2013 the Intergovernmental Panel on Climate Change (IPCC) reported in its Fifth Assessment Report that atmospheric concentrations of greenhouse gases such as CO_2, methane and nitrous oxide had risen to the highest levels ever seen in 800 000 years. Greenhouse gas emissions between 1951 and 2010 increased the earth's surface temperature on average by 0.5-1.3°C. In addition, climate change is causing more extreme weather, such as more severe rainfall events and droughts, and is causing sea levels to rise.

In 2015, at the 21st UN climate change conference, nearly 200 parties passed the Paris Agreement. In order to prevent the potentially catastrophic impacts of climate change, the parties agreed to limit the global temperature rise above pre-industrial levels to 2°C at most, with a preferable target of only 1.5°C. More recently, most of the world's largest economies have announced more ambitious "net-zero" targets that aim for either carbon neutrality or full greenhouse gas emissions neutrality. For example the European Union and Japan have set targets to achieve net-zero greenhouse gas emissions by 2050, and China has set a goal to achieve carbon neutrality before 2060.

Meeting the Paris Agreement target requires a profound transformation of global energy systems, from those largely based on fossil fuels to those that enhance efficiency and are based on renewable energy. There must also be widespread substitution of electricity for liquid fuels. Such electrification not only significantly increases the efficiency of the energy systems, it also makes it possible to achieve a higher share of renewables in the total primary energy supply when combined with further deployment of carbon-free electricity (mainly from solar photovoltaics [PV] and wind).

(2) Innovation, improvement and cost reduction

In the field of renewable power generation technologies, the efficiency and economy of wind and solar power continue to make remarkable improvements. Over the past decade the unit capacity and efficiency of wind power have increased greatly, as has the efficiency of solar PV modules. These technological improvements, alongside economies of scale, increasingly competitive supply chains and growing developer experience, have made renewable power generation technologies the least-cost option for new capacity in almost all parts of the world (IRENA, 2020d). According to the latest cost data from IRENA the global levelised cost of electricity (LCOE)[1] on a weighted average basis from utility-scale solar PV and onshore wind is potentially set to fall to USD 0.039/kWh and USD 0.043/kWh in 2021, making new renewable power projects cheaper than even operating an increasing number of existing coal-fired power plants. In the future the full extent of innovations occurring around renewable power generation will enable even greater cost-effectiveness and accelerate larger-scale utilisation. Innovations extend to improved battery technologies, innovative service models such as aggregators to enhance system flexibility, and the use of intelligent control systems through greater digitalisation.

1 *The LCOE is a measure of the average net present cost of a unit of electricity generation for a generating plant over its lifetime. The lifetime cost of electricity generation is discounted to a common year using a discount rate that reflects the average cost of capital.*

1.3 CLEAN ELECTRICITY BECOMES THE PRINCIPAL FUEL IN THE CURRENT ENERGY TRANSITION

As the twin drivers of climate action and renewable energy innovation create profound changes in global energy systems, a consensus is building around the key pillars of the next sweeping energy transition.

First, **clean electricity** is poised to become the principal fuel of our energy systems, as electricity from high-carbon fossil resources continues to be replaced with clean, low-carbon electricity from wind, solar, hydro and other renewable sources. Among the different renewable power generation options, low-cost solar PV and wind power technologies, which are VRE sources, are expected to account for the majority of total electricity generated globally.

Equally important as the expansion VRE for power, the **electrification of energy services** will become pervasive, as end uses of energy switch from fossil fuels to electricity. Electric or fuel cell vehicles will largely replace fossil-fuelled cars and trucks, and heat pumps and electric boilers can substitute for oil and gas furnaces in buildings and industry. Electricity from renewables can also be used to make hydrogen or synthetic fuels for applications where direct electrification is difficult. A wave of productive investment in new and upgraded network infrastructure for transmission, distribution, storage and charging will underpin this electrification. The simultaneous implementation of energy efficiency measures will ensure that transformed end uses make the most of clean electricity.

The third pillar of the transition is crucial, as it will be the key link between the expansion of renewable generation and widespread electrification. It is the **deployment of "smart" digital devices**, information and communications technology (ICT), and related operational practices, which offer the prospect of even greater efficiency gains through much more flexibility and optimisation of demand, delivery and use of renewable electricity. The integration of such smart approaches into the transition is crucial to reduce the risk of rising peak electricity loads and to optimise investment in new grid infrastructure. Smart digital technologies also expand the opportunities for electricity utilisation and make it possible to take full advantage of the growing amounts of cheap renewable power – particularly VRE from solar and wind.

Taken together, this vision is described in this report as **"smart electrification with renewables"** (hereafter "smart electrification")[2] and unlocks the potential synergies between major increases in renewable power generation, electrification and digitalisation. At the same time, it creates the conditions for an unprecedented co-ordination of their deployment and more efficient use across demand sectors – power, transport, industry and buildings.

2 *This has also been referred to as "RE-Electrification" elsewhere in IRENA work, for example in the preview of this report for policy makers prepared for the ninth session of the IRENA Assembly (IRENA, 2019a).*

1.4 THE SMART ELECTRIFICATION TRANSITION BRINGS NUMEROUS MAJOR BENEFITS

Smart electrification can make power systems more flexible and resilient, while making the wider energy system more secure and less reliant on fossil fuels. At the same time, it offers significant efficiency gains in energy use. Because using electricity for end uses like transport and buildings heating systems is more efficient than using fossil fuels, smart electrification will actually reduce total energy demand for the same amount of energy services, and boost economic productivity. It also reduces pollution, leading to improved air quality and health.

Smart electrification also unlocks new synergies between electrification and renewables themselves. For example, in today's traditional electricity systems, demand is experienced as variable but relatively inflexible and predictable. Small variations can be covered by operational reserves at fossil fuel or hydro generators. Most flexibility to meet variable demand comes from the supply side, where dispatchable power plants can be ramped up and down.

Smart electrification creates a very different system. In this system, overall demand for electricity will rise significantly in transport, buildings and industry, which creates new markets. Solar and wind will be key suppliers to these new markets (IRENA, 2020a). At the same time, the electricity they generate can vary depending on prevailing weather conditions, and having a high share of such VRE in a power system poses increased operational challenges. Smart electrification strategies meet such operational challenges by looking beyond the generation side of the power system and tapping all available sources of flexibility. This is particularly the case for flexibility of demand over a wide range of time scales. To take just one example, the charging of electric vehicles (EVs) can be ramped up or down within milliseconds or shifted by several hours, with the support of new digital technologies. Such "smart-charging" approaches in transport can reduce the distribution grid investment needed for the uptake of EVs by between 40% and 90% (IRENA, 2019f). The potential for similar forms of demand-side management and response that are unique to an electrified system also exists in the buildings and industrial sectors.

Smart electrification with renewables therefore creates a virtuous cycle, where electrification drives new uses and markets for renewables, which then accelerates the switch to electricity for end uses, creating the potential for more flexibility and thus driving further renewables growth and technological innovation. Growth and innovation also reduce costs and create additional investment and business opportunities.

1.5 CHALLENGES TO ACHIEVING SMART ELECTRIFICATION

This major transformation is not trivial. Energy systems are both complex and highly integrated, making them difficult to change. On the policy side, they are highly dependent on entrenched regulations, taxes and subsidies, which require considerable political will to adjust. Even where there is political will, transforming markets and supply chains – for example, the global car industry to EVs, or home heating to heat pumps – may still take many years. People replace heating equipment and cars every 10-15 years, and in some parts of the world the building stock is being renovated at a rate of less than 1% per year. Any transition also creates winners and losers, and those who do not benefit may resist change. The distribution of cost and benefits needs to be fair and just in order to achieve broad acceptance.

On the technical side, the transition requires integrating large amounts of VRE into the grid, which involves matching supply and demand in the face of varying generation and peak production that may not match peak demand. It requires improved co-ordination between sectors of the economy, both in planning and operation. In addition, new infrastructure must be built or expanded for the power grid, EV charging networks and hydrogen or synthetic fuel production facilities.

The basic technologies needed for the transition already exist, and are being constantly improved or made less expensive by continuing innovation. Scaling up this innovation will be critical to accelerate the energy transition and lower its overall cost.

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2 ELECTRIFICATION TECHNOLOGIES, SMART STRATEGIES, AND SYSTEMIC TRADE-OFFS

KEY MESSAGES

- Technological pathways for future electrification are increasingly well known across sectors – electromobility, electric heating and electrified production of hydrogen and synthetic fuels, as well as electrification of industrial processes, are all viable and have high potential – but they are at various stages of development.
- While rapid and uncoordinated electrification of mobility and heating could threaten to increase system peaks, smart electrification enabled by digitalisation and low-cost renewables has major potential to reduce peak loads, thus optimising investments in the grid or additional generation capacity.
- Better matching of demand and VRE supply patterns – through time shifting with smart electrification technologies, or hydrogen to provide seasonal and long-term energy storage – can not only help to integrate VRE into power systems, but also expand the markets for them to serve.
- In transport, well-planned smart charging networks are critical to avoid peak load increases due to electrification, and instead enable EVs to offer significant demand flexibility, therefore reducing system costs by making the most of VRE capacity. With the right design, plugged-in vehicles can also provide grid services, reduce balancing costs, and improve the integration of renewables at both system and local levels for transmission and distribution (T&D) system operators.
- In buildings, smart heating and cooling can offer similar benefits through heat pumps connected to smart electricity meters, thermostats and building management systems. These can serve as distributed heating loads to participate in demand response programmes, boosting overall system efficiency. In this case, it is critical to pair electrification with building efficiency, so inefficient buildings do not cause massive increases in electricity use.
- Even though electrification reduces the overall amount of primary energy required due to efficiency gains, the electrification of heating and cooling can raise existing winter peaks in heating for buildings and summer peaks for cooling, depending on climate. A key solution can be thermal storage to complement seasonal VRE production, which allows heat to be stored in summer for use in winter, but also for storage in winter to be used later for cooling, in much the same way that natural gas is now stored to meet anticipated future demand.
- Although renewable energy generation is often far more distributed than traditional power plants, with smart electrification this quality can be a source of new solutions rather than potential problems. Aggregation of distributed resources through digitalisation and ICT can effectively make them behave like a single source that can provide fast-ramping ancillary services, replace fossil fuel-based reserves and significantly reduce pressure on grid network infrastructure, either by alleviating flexibility or congestion issues, or even deferring and preventing the need for grid upgrades and expansion.

- In industry, the expansion of low-cost renewable sources around the world is providing unique opportunities to remake or create new commodity markets while increasing the sector's share of electricity – the relocation and co-location of industrial operations to areas with high-quality low-cost renewable sources offer the advantage of optimal hydrogen production conditions. This smarter approach to industrial electrification has particularly high potential to transform iron and steel production, as well as other hard-to-electrify processes in other industries.

- Seasonal hydrogen storage can also allow surplus renewable electricity to be stored for months, thus deferring or reducing investment in the electricity network that might be needed with VRE. Storage could be especially valuable in places with line congestion and high concentrations of VRE.

- Even with the smart electrification strategies described, there are serious economic trade-offs between direct and indirect electrification pathways at the system-wide level. Early studies are attempting to identify the lowest-cost combinations of direct and indirect electrification for overall generation and T&D infrastructure, with clear insights into the sensible extent of different pathways across sectors.

- The majority of studies find that at the system-wide level, renewable energy capacity needs appear to be the largest infrastructure investment for both direct and indirect electrification. As such, a general principle of minimising those capacity needs in efficient system-wide planning is logical.

- Transmission and local distribution networks may represent smaller investment requirements relative to electricity generation capacity, but they can still be critical bottlenecks for electrification in certain areas, and often merit their own dedicated analysis and investment.

- Across the board, even before electrification occurs, strong demand reductions through energy conservation and efficiency are proposed in nearly all studies regardless of sector, to reduce the need for unnecessary electricity generation capacity.

- District heating systems are seen to play a particularly important role in the most efficient use of electricity in heating and cooling, particularly given the typically lower cost of their overall infrastructure requirement (across generation, T&D, storage and end-use technology) as compared to decentralised heat pumps in urban environments. Such thermal networks can also offer larger-scale and more diverse storage solutions for seasonal heating and cooling than a fully electrified system, ideally resulting in less overall infrastructure capacity needs. Losses associated with such centralised systems need to be factored into the calculations as well.

- Once efficiencies and alternatives have been exhausted, studies propose different optimal shares of remaining direct and indirect electrification, largely following the principle of minimising electricity generation capacity needs.

- What could be thought of as light uses – for example, light-duty vehicle demand, rural heating and cooling demands, and even light industry – should be directly electrified to the fullest extent possible given the availability of increasingly competitive end-use technologies (EVs and heat pumps) and access to smart electrification strategies which reduce their network infrastructure costs.

- What could be thought of as heavy uses, which require energy-dense fuels – for example, aviation, long-distance shipping and high-temperature heating – are candidates for majority indirect electrification through green hydrogen and its derivative e-fuels if no decarbonisation alternatives are available. The additional electricity generation they require is seen as necessary due to the lack of competitive direct electrification end-use technologies.[3]

3 *In this report, e-fuels (electrofuels) are assumed to be generated using renewable energy. Hydrogen is produced using renewable electricity and then combined with carbon dioxide, for example from industrial exhaust gases or from the air, to form a hydrocarbon with zero net greenhouse gas emissions. The process is commonly known as Power-to-X. Box 4 contains more details on this topic.*

2.1 INTRODUCTION

Clearly defined technology options already exist to increase electrification in the three major end-use sectors discussed in this report: buildings, transport and industry. Combined with renewable electricity generation and key infrastructure networks, these options make it possible to achieve crucial decarbonisation targets, such as the goals in the Paris Agreement. IRENA's work has provided a thorough and realistic overall pathway toward such long-term electrification, as described in Chapter 3.

However, uncoordinated electrification during the transition could pose major issues and have unintended consequences, such as a rapid expansion of peak electricity demand that surpasses available capacity. There are also questions about infrastructure investment needs for different electrification pathways, and which pathways require more strategic decisions to achieve the scale required.

This chapter addresses these questions by discussing strategies for smart electrification with renewables. We define such strategies as those promoting electrification with renewable energy generation in an intelligent way, without unduly increasing system costs or threatening the security of supply.

Before discussing the importance of smart electrification, the chapter provides a more general introduction to electrification technologies, trends and cost drivers for the buildings, transport and industrial sectors. Following that, we assess the role that particular smart electrification strategies play to ensure that high levels of electrification and renewable energy are compatible and well-integrated. While measures to improve supply-side flexibility are also important for VRE integration, they are not the focus of the strategies in this chapter. Finally, we place smart electrification in a system-wide context, exploring the implications of different pathways and strategies for overall infrastructure investment needs.

Box 2. Real-world feasibility – Widespread end-use electrification with renewables in different parts of the world

Although this report explains the importance of electrification, it may not be necessary for every energy system in the world to operate with 100% or even very high shares of end-use electrification, given decarbonisation alternatives. Section 2.4 explores the trade-offs associated with different electrification and decarbonisation pathways at such high shares.

This does not mean, however, that such widespread electrification is not feasible in a variety of environments – on the contrary, real-world examples already exist of countries that have harnessed best practice and either already achieved full or high shares of electrification with renewables, or set clear pathways toward achieving it.

Norway

Norway has already achieved very high levels of electrification in its energy system, comparable to the levels the global energy system needs for temperatures to stay below 2°C by 2050 (see Chapter 3 for more detail). In 2018 electricity represented 48% of final energy consumption in the country. This is possible thanks to historical development of the country's abundant low-cost hydropower resource, which has been a critical enabler of high electrification shares in buildings and industry (84% and 66% of final consumption, respectively) (IEA, 2020a).

In Norwegian buildings most space heating is already electric, with significant shares of district heating, and the government has recently pledged to ban the use of oil for heating. Most Norwegian onshore industries are also highly electrified, and the decarbonisation of offshore petroleum facilities and onshore industry process emissions would be the next phase of the process. Transport is the only sector lagging in electrification (2% of final energy consumption in 2018). While rail is mostly electric, road transport is still dominated by fossil fuels. However, as noted in Section 2.2.2, this has a strong electrification trend too. Norway has led the world in market share of plug-in EVs, surpassing 50% of new sales in 2017, and has established a target for 100% of car sales to be zero-emission vehicles by 2025.

If the ongoing electrification of the transport sector continues as planned in the coming years, the Norwegian energy system could be dominated by electricity in most end uses by 2050. A recent study by industry association Energi Norge – a utility industry advisory body – concludes that it is possible for the country to operate entirely using clean electricity by 2050 (Energi Norge, 2017).

Denmark

Although Denmark is starting from a lower share of electricity in final energy consumption than Norway (at nearly 20% in 2018) (IEA, 2020a), and does not have access to major low-cost hydropower resources, the country is now planning to scale up electrification through development of its offshore wind resource to meet 2030 climate targets. At least 5 GW of new offshore wind capacity is now planned in the coming years on the world's first so-called energy islands (one of which is artificial) in the Baltic and North Seas, with potential for further expansion (Danish Ministry of Climate, Energy and Utilities, 2020). The islands would produce more electricity than current annual household consumption, and will be used to expand the current share of electricity in buildings (28% in 2018) alongside a dedicated phase-out of individual oil and gas boilers and phase-in of heat pumps and district heating before 2030.

The offshore wind islands will also feature investment in Power-to-X technologies, which can eventually use excess and dedicated wind generation to produce green hydrogen. This indirect electrification through green hydrogen will allow for the decarbonisation of sectors beyond buildings and road transport, which already have electric end-use technologies readily available and set to be significantly expanded by 2030. Although they are not major sources of energy consumption in the country, the government is specifically targeting heavy land, sea and air transport, as well as various industrial processes for such indirect electrification (current industry share of electricity is at 33%) in a bid to reach carbon neutrality by 2050.

United Arab Emirates

Like Denmark, the United Arab Emirates has a relatively lower overall share of electricity in final energy consumption than the global leader Norway. In 2018 the country's electricity share stood at 18% (IEA, 2020a). However, it has one of the highest shares of electricity in buildings sector energy consumption at 96% (in 2018), and a very different sectoral and temporal profile of energy consumption. For example, given the country's climate the majority of energy use in buildings is related to cooling (air conditioning and refrigeration) rather than heating, which makes the current use of electric end-use technologies more straightforward. But the majority of that electricity currently comes from natural gas, and air-conditioning demands also approximately double during summer peaks. Industry and non-energy chemical/petrochemical demand also together make up a much higher share of overall energy consumption than in many countries, at 61% in 2018 (individually 56% and 5%, respectively).
The United Arab Emirates thus faces uniquely challenging circumstances in shifting end uses to renewable electricity. However, there is ongoing discussion of how the country can use its unique geographic and industrial circumstances to lead the world in demonstration of smart electrification

options (Gielen, 2020). For example, the country accounts for roughly 4% of the world's primary aluminium production, which, in addition to electrification potential, also offers the potential for significant flexibility to complement variable renewables. Liquid aluminium storage can enable continuous downstream operations, while smelter electricity demand can be controlled to free up to 10-20% of peak electricity demand. There is also unique storage potential in the country's major desalination processes, with water being storable for months or years.

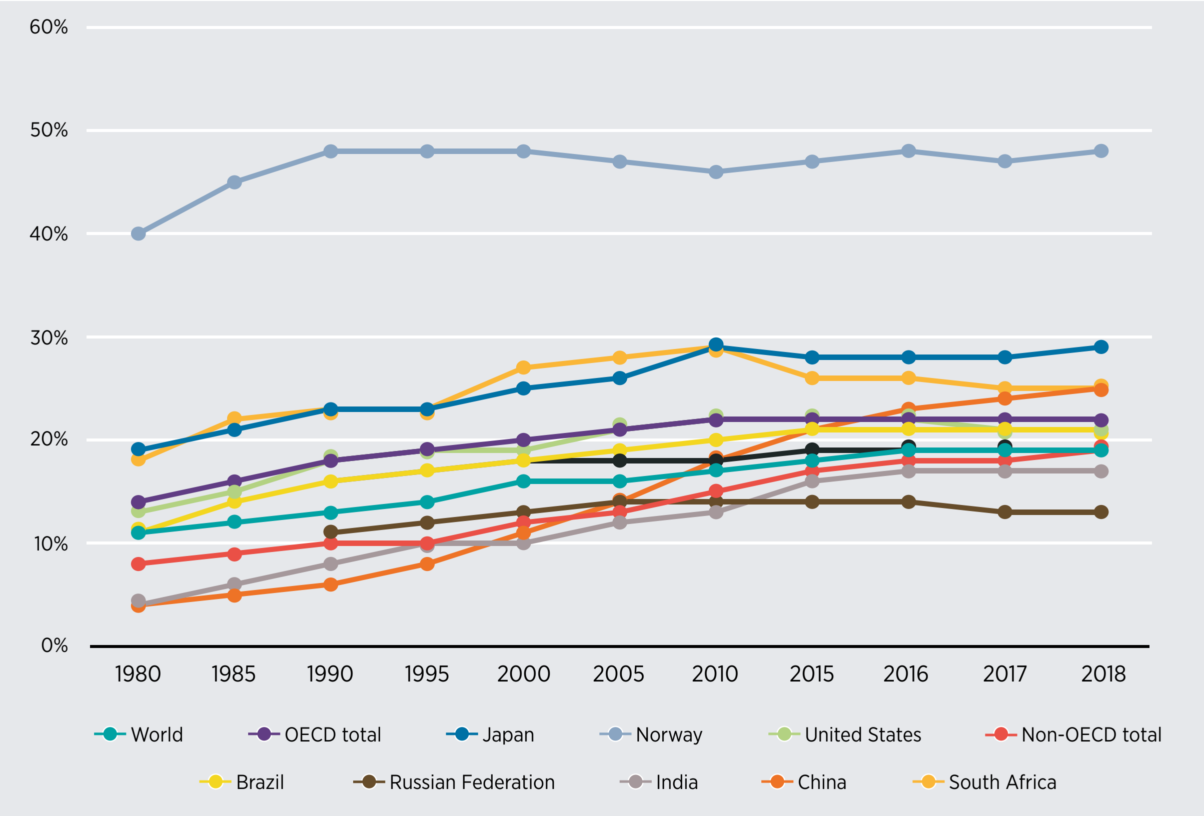
These options, alongside significant expansion of excellent solar power resource in the form of concentrating solar power (CSP) and PV, and solar facilities dedicated to the production of green hydrogen, can form a package of realistic alternatives to meet demand currently met by natural gas (IRENA and Masdar Institute, 2015). The country's major role in global shipping and supply of bunker fuels (for example, supplying 8% of international shipping bunkering in 2017) could also be a source of innovation for a hard-to-decarbonise sector. In the end, alternatives for achieving decarbonisation, such as biofuels, may prove to be more feasible for such processes due to current infrastructure characteristics (see Section 2.4 for more discussion along these lines), but feasibility will be tested in countries like the United Arab Emirates, which are already aiming to take a leading role in exploring different pathways.

2.2 ELECTRIFICATION OF END-USE SECTORS – HIGH-LEVEL OVERVIEW OF TECHNOLOGIES, TRENDS AND COST DRIVERS

This section describes key end-use technologies and how they can be used to increasingly electrify three sectors: buildings, transport and industry. In 2018 each of these three sectors used about one-third of global final energy consumption. Currently the level of electrification varies around the world. The share in OECD member countries is generally slightly higher than that of non-member countries, for example, but the growth rate in the BRICS countries (Brazil, Russian Federation, India, China and South Africa) is generally higher than that of the OECD countries in recent years – especially in China (Figure 2). The overall level of electrification is related to a range of contextual factors such as level of economic development, resource endowment, industrial structure and policies driving the competitiveness of alternative energy carriers. For example, Norway appears as an outlier in the data thanks to historical development of the country's abundant low-cost hydropower resource, which has been a critical enabler of high electrification shares in buildings and industry (see Box 2 for more details).


Photo: KENNY TONG / Shutterstock.com

Figure 2 The level of electrification in final energy consumption in selected countries (1980-2018)

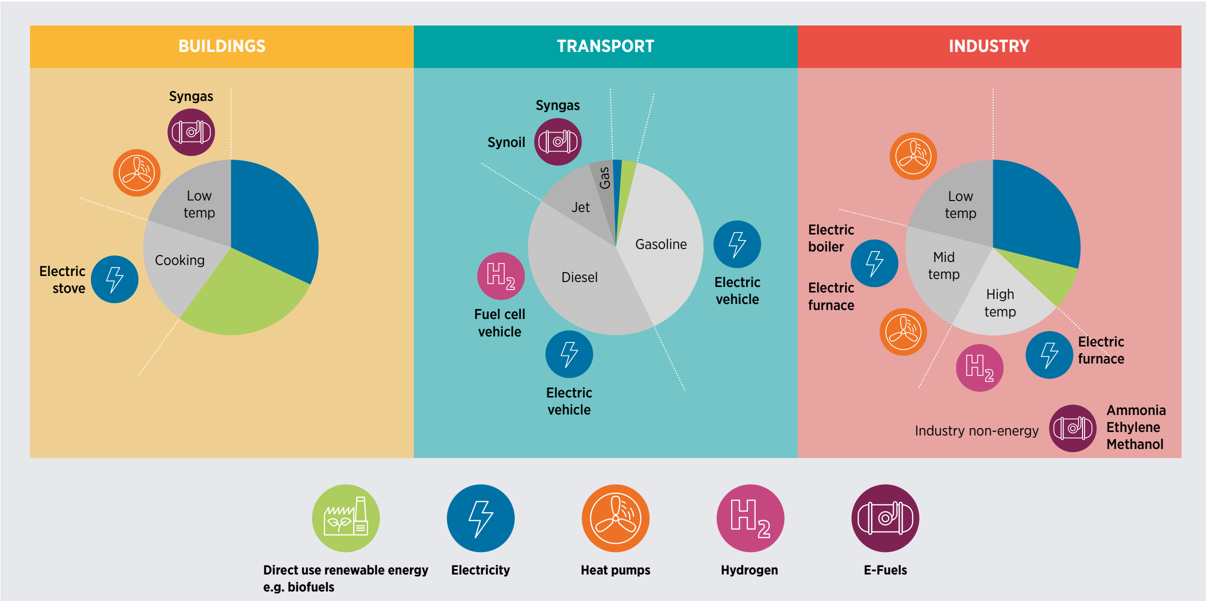


Source: IEA (2020a).

Figure 3 summarises current global energy consumption in each sector and shows which technologies could displace various end uses of fossil fuels. The subsections that follow provide more detail on the potential technological composition of electrification pathways for each sector. Conceptually, solutions can be seen to fall into two broader categories – direct and indirect electrification. Direct electrification entails consumption of electricity directly by the end-use technology, while indirect electrification involves conversion of electricity to another type of energy carrier (e.g. hydrogen) before consumption. Box 4 contains a more detailed view of indirect electrification, or Power-to-X solutions.

While one of the principal aims of these electrification pathways is decarbonisation, electrification is not the only decarbonisation option for the sectors discussed. Indeed, as IRENA's Renewable Energy Roadmap (REmap) work shows, decarbonisation will require a number of complementary solutions in addition to electrification, such as ambitious increases in energy efficiency and sustainable bioenergy. A full discussion of these solutions, and the balance between them and electrification in the future energy mix, is beyond the scope of this report, but is partially addressed in Section 2.4.

Figure 3 Schematic summary of most prominent potential applications for electrification



BUILDINGS

Buildings currently use about 122 EJ of energy globally per year, or about 30% of global final consumption (IEA, 2020a). More than half of that energy is supplied as natural gas, oil, coal or biomass. Homes and other residences consume about 70% of buildings energy, while commercial and government buildings use the rest. Currently electricity supplies about 24% of the energy used in residential buildings and 51% of that used in commercial and public buildings.

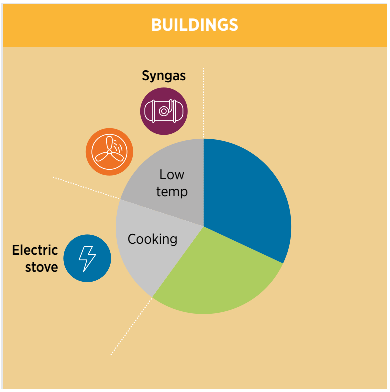
Key technology options to achieve higher electrification in the buildings sector are:[4]

(1) Use of heat pumps for space and water heating or cooling.

(2) Electrification of space and water heating using electric heaters or boilers, and use of electric stoves and ovens for cooking.

(3) Use of renewable electricity to produce fuels such as hydrogen or its derivative e-fuels, which are then provided through existing or new gas T&D networks.

4 *Electric resistance heating involves passing an electric current through a dedicated material to create heat. Appliances such as electric furnaces or boilers use such materials to heat air or water, which can be distributed through fans, circulated in piping or stored for later use. Rather than generate heat through electricity, heat pumps transfer heat from the ambient air (air-source heat pumps) or the ground (ground-source heat pumps) by using electricity to heat or cool refrigerant (through physical conversion between its liquid and gaseous states), which can then be distributed for space/water heating and cooling. An often-cited advantage of heat pumps over electric resistance heating systems is their superior efficiency, as they can be 2-5 times more efficient and thus require less electricity for the same service.*



Both electric resistance heating and heat pumps can be used in individual buildings as well as in large-scale district heating systems. While fossil-fuel technology still makes up about half of global sales of heating equipment for buildings, conventional electric heating, heat pumps and district heating and cooling categories have grown consistently in recent years to account for roughly 40% of new sales (as of 2017) (IEA, 2019a). Europe, the United States and Japan have seen significant shares of this equipment already installed. Nearly 11 million heat pumps have been installed in Europe for both individual and large-scale uses, with Norway and Sweden leading the way at roughly 45% and 35% of households receiving heat pump supply, respectively (European Heat Pump Association, 2018). In the United States, around 12 million households rely primarily on heat pumps for space heating, and an additional 12 million use other types of electric heating. Together, these add up to about 20% of total households (EIA, 2018). In Japan, 6.3 million home heat pump systems were installed between 2001 and 2018, among 58 million households (HPTCJ, 2019).

A less mature alternative to direct electrification of buildings energy demand or heat pumps is the use of hydrogen and its derivative e-fuels, primarily synthetic methane, as an alternative to natural gas. While this approach is not yet widespread, it could have advantages if it allows for the use of existing gas infrastructure and thus helps to avoid stranded assets. Whether or not this potential benefit makes a material difference in the system-wide prospects for hydrogen and e-fuels in buildings is discussed in more detail in Section 2.4.

Buildings: Key network and end-use infrastructure requirements and cost drivers

A considerable amount of new and upgraded network and end-use infrastructure will be involved in the process of buildings sector electrification.

For **electric heaters/boilers and heat pumps**, those needs include:

- Manufacturing and installing electric heaters and/or boilers.
- Manufacturing and installing heat pumps.
- Connecting the electrified sources of heat to a thermal grid (in the case of district heating systems).
- Renovating buildings to make them more efficient.
- Installing smart meters to enable smart building services.
- Introducing smart building services themselves (such as power flow management, digitalisation to facilitate intelligent exchange of information and advanced algorithms for local integration with distributed local sources).

As for the cost of these elements, investment costs for heat pumps are typically substantially higher than for electric heaters and boilers, as well as gas boilers and oil-fired solutions, but operating costs are much lower due to heat pumps' high efficiency.

A forecast of installed costs for different types of heat pumps is provided in the regularly published technology catalogues of the Danish Energy Agency and Energinet (n.d.). As shown in the tables below, economies of scale affect unit cost. For a 10 kW unit, costs were predicted to decline from EUR 10 000 in 2015 to EUR 7 600 by 2050. Other sources provide similar cost estimates, with exact costs depending on local contexts.[5] For residential and light commercial applications, the typical size of a heat pump system is 4-50 kW, while those for district heating range from 100 kW to MW-scale (Nowak, 2018).

Table 1 Installed cost of heat pumps in Denmark and forecast cost reductions (2015-2050)

Size (heat production capacity)	5 kW	10 kW	15 kW
Air-to-water, investment (EUR/unit)	7 500	10 000	12 000
Ground-source, investment (EUR/unit)	12 500	16 000	19 000

Heat pump, air-to-water, existing one-family house	2015	2020	2030	2050
Heat production capacity for one unit (kW)	10	10	10	10
Specific investment (EUR 000/unit)	10	9.4	8.5	7.6

Source: Danish Energy Agency and Energinet (n.d.).

Heat pumps work best in the context of large heat exchange areas and well-insulated buildings. While these features may be present in new buildings, older building stock typically requires retrofitting with additional insulation and energy efficiency measures to realise the efficiency gains from heat pumps. Highly energy-efficient buildings are thus a critical prerequisite if electrification of heat is to deliver system-wide efficiency improvements. As a result, substantial retrofitting of existing buildings may be necessary. While retrofitting costs will depend on local circumstances and the type of building stock, a Belgian study of heating strategies for buildings placed the total cost of a light retrofit of building envelopes (including full insulation and upgrading of doors and windows) at EUR 705/m^2 and at EUR 1 080/m^2 for a deep retrofit (Vandevyvere and Reynders, 2019).

5 Air-source heat pumps (air-to-air) are also considered in other sources. In a 2012 study in the United Kingdom, the installed cost of an 8.5 kW air-source heat pump was USD 10 900 (Delta Energy & Environment and Energy Networks Association, 2012). That cost was anticipated to decline to USD 8 500 by 2045. Ground-source heat pumps of a similar size would cost about twice as much. These investment costs compared to USD 2 900-3 500 for gas boilers, USD 6 300-7 800 for oil boilers and USD 3 100-5 100 for electric storage heaters. Other studies in the European context provide estimates around those levels – a study of the EU28 countries contains higher estimates for the cost for residential-size air-source heat pumps at USD 13 400 by 2050 (Connolly, Lund and Mathiesen, 2016), while another in the Belgian context cites current costs for residential air-source heat pumps at EUR 8 000 (Vandevyvere and Reynders, 2019). Both studies, however, maintain similar assumptions that these investment costs are roughly double those of alternative fossil-fuelled boilers. To give another example, in Japan, heat pumps are mainly used for water heating at home. A standard unit with a 370 litre tank costs USD 1 500-2 000, plus another USD 2 000 for installation (Kakaku, 2019). These heat pumps cost twice as much as conventional water heating systems, but their operational costs are about one-fifth of those of conventional units (Abdelaziz et al., 2012).

Where achievable, despite the need to build a district heating network, district heating systems and other centralised solutions may be more cost-effective than installing heating units in every building, as they can offer load diversity, greater potential to use thermal storage and reduced retrofit costs. System-wide assessments of these alternatives are discussed in Section 2.4. In terms of household costs, in the UK context in-house costs for the heat interface in district heating systems have been estimated to be around USD 2 900 (Delta Energy & Environment and Energy Networks Association, 2012). In the Belgian context, Vandevyvere and Reynders (2019) placed district heating connection costs for residential buildings at EUR 8 000 per building.

Although smart meters and services are more costly than traditional metering in buildings, their costs are much smaller relative to the other infrastructure items discussed. For example, an analysis of over 16.6 million metering upgrades in the UK Smart Metering Implementation Programme shows average meter costs of GBP 36 for electric, GBP 53 for gas, and GBP 120 for advanced dual-fuel, while installation costs ranged from GBP 88 to GBP 143 per meter (BEIS, 2019a).

For **hydrogen and e-fuels**, buildings, network and end-use infrastructure needs include:

- Upgrading end-use appliances, such as gas boilers/furnaces, for hydrogen/e-fuel use.
- Upgrading natural gas T&D networks to use high levels of hydrogen or e-fuels.
- Installing smart gas meters to enable smart building services.
- Introducing smart building services themselves (such as thermal flow management, digitalisation to facilitate intelligent exchange of information and advanced algorithms for local integration with distributed local sources).

Hydrogen and synthetic natural gas could be delivered to buildings using existing natural gas distribution systems. But while low shares of hydrogen (10-20%) can be blended into natural gas without significant technical challenges or major investment, most appliances and most of the transmission system, and part of the distribution system, would require major modifications or upgrades in order to use higher shares of hydrogen (IRENA, 2019c). For example, gas flow detectors and quantity transformers, as well as tanks and gas boilers, may need adjustment or modification, and increased safety measures may need to be put in place due to the different gas composition.

In addition to such upgrades enabling higher blending shares, the main network infrastructure needs are installing smart gas meters and adding the same type of building services as discussed for heat pumps above (power flow management, digitalisation to facilitate intelligent exchange of information and advanced algorithms for local integration with distributed local sources).

While the cost of producing these fuels generally will be higher than the cost of network infrastructure upgrades (see Box 4 for more details), the cost of those upgrades can be significant, especially as the share of hydrogen and e-fuels increases. Current network conversions offer a window into possible costs. Germany for example, is switching 30% of the country's natural gas customers from natural gas with a low methane content (L-gas) to gas with a higher methane and a higher calorific content (H-gas). The expected cost of the necessary network renovations and upgrades for the 10-year project is EUR 7 billion (USD 7.8 billion) (IRENA, 2019c).

TRANSPORT

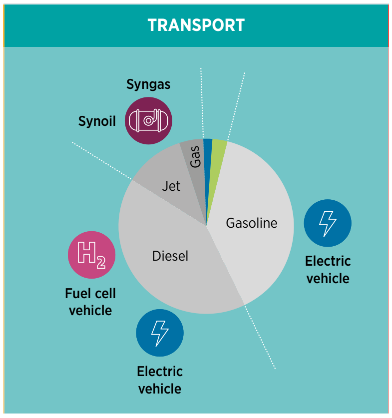
Electricity currently provides only about 1% of the roughly 121 EJ of energy used for transport globally – which includes passenger and cargo transport by road, rail, maritime shipping and aviation (IEA, 2020a). More than two-thirds of that electricity is used for rail transport globally, and much of the rest is used by tram and subways.

Key technology options to expand **electrification in the transport sector** are:

(1) Using EVs, including passenger cars, trucks and buses, mainly (but not exclusively) to meet short- to mid-distance mobility needs.

(2) Use of renewable electricity to produce hydrogen to power fuel cell electric vehicles (FCEVs) and trains for long-haul transport.

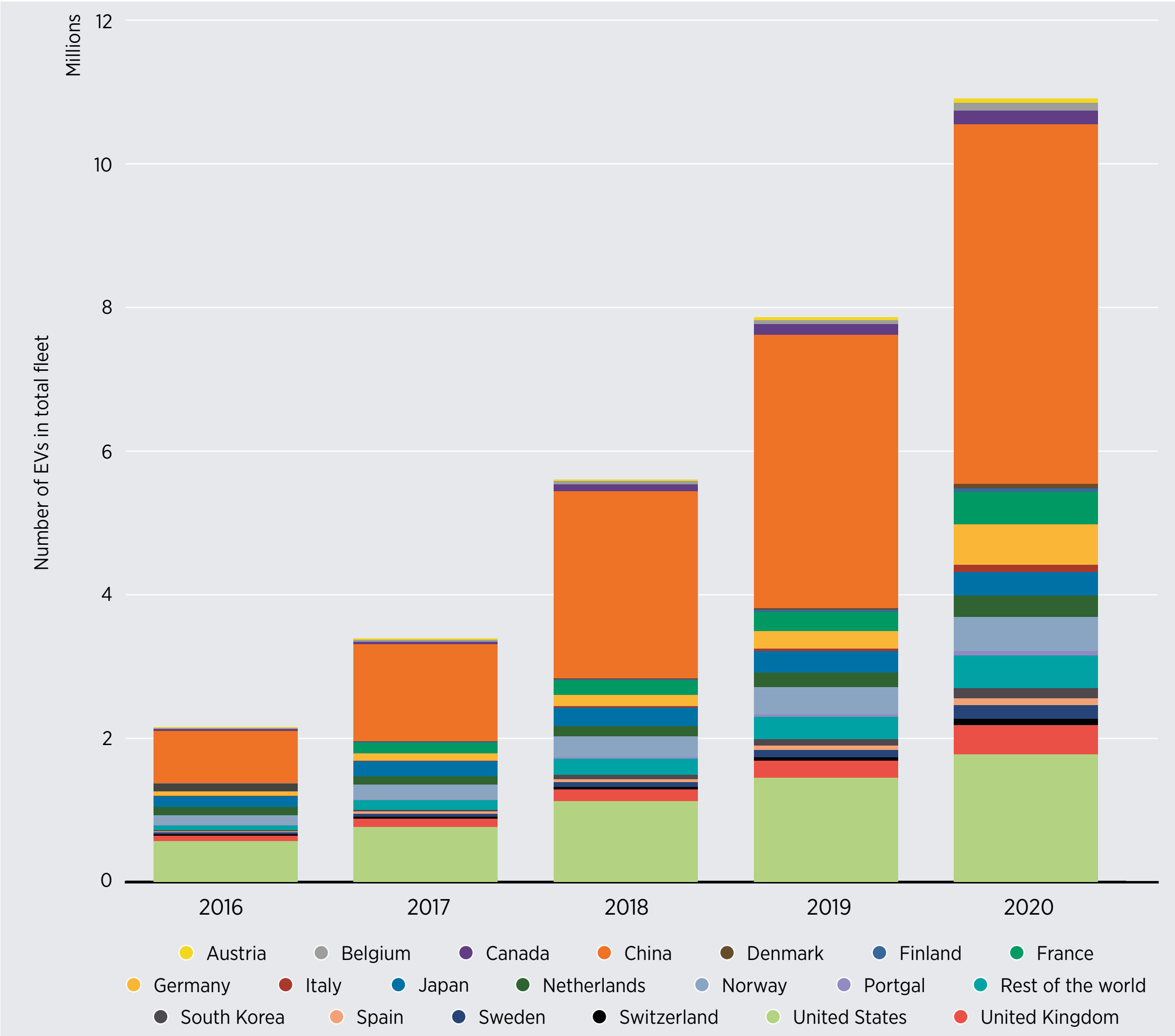
(3) Use of renewable electricity to produce e-fuels to replace fossil-based transport fuels in energy-intensive freight and long-haul transport sectors (i.e. maritime and aviation).



Roughly 11 million EVs are currently on the road, including battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (ZSW, 2020). The amount of electricity they use is not yet significant at the global scale, but sales of EVs are increasing quickly. In 2020 sales of electric cars increased by 41% from the previous year, while at the same time the global automobile market experienced a 16% contraction. This momentum continued in 2021, as sales in the first quarter of 2021 reached nearly two and a half times those in the same period a year earlier (IEA, 2021). While Norway leads the world with a domestic EV market share of about 56%, China is the clear driver of recent and near-term acceleration, accounting for more than half of passenger EV sales in recent years and nearly all electric bus sales (IEA, 2021). Passenger EVs beyond cars and buses play an important role in e-mobility as well; as of 2016 the number of electric two- and three-wheelers stood at roughly 200 million, with some estimates of tenfold growth to over 2 billion units projected by 2050 in a strong decarbonisation scenario (IRENA, 2019g). EV growth may be further increased by the emergence of self-driving vehicles and increases in ride sharing and other types of shared mobility, both of which are made possible by new digital technologies and which are especially complementary with EVs (Deloitte Center for Energy Solutions, 2017).[6]

6 *For example, EVs have an operating cost advantage over internal combustion engine vehicles in high-utilisation ride-sharing fleets, and are easier to integrate with autonomous technology.*

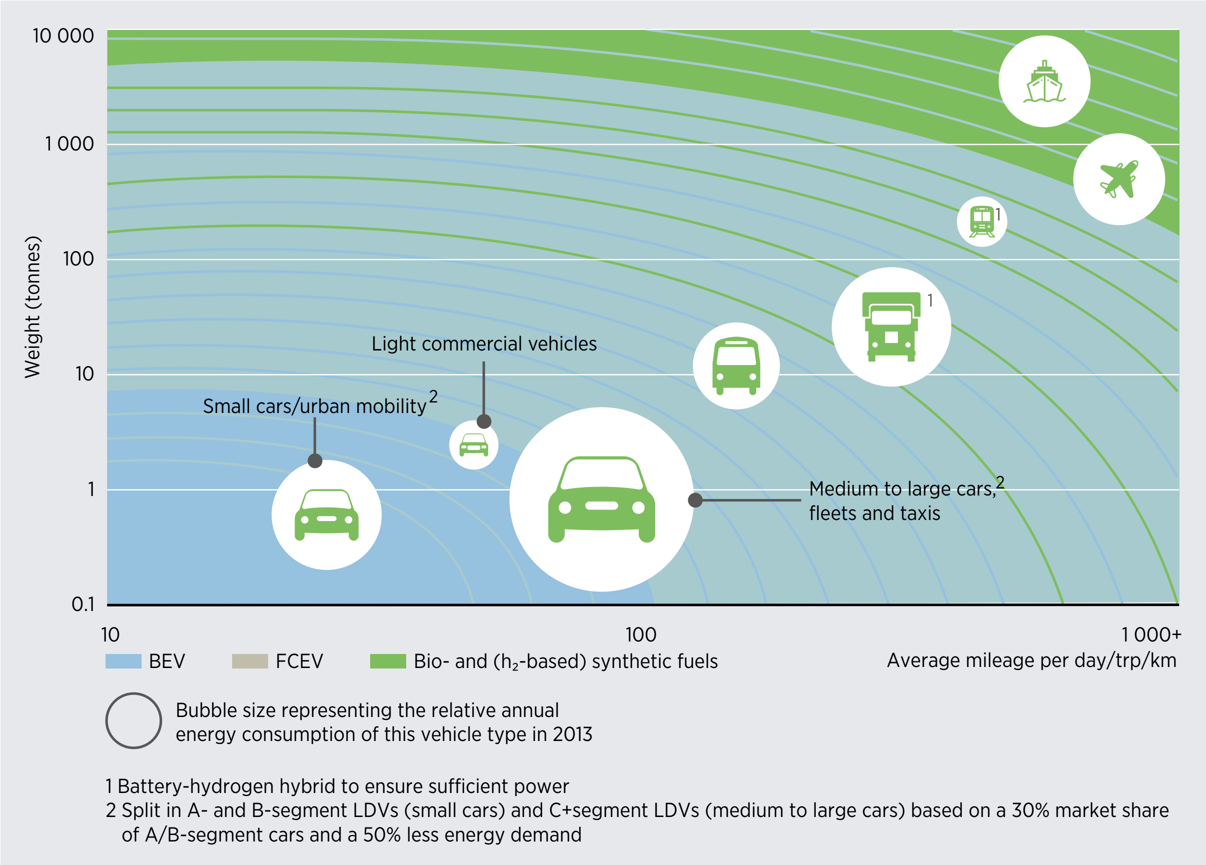
Figure 4 Global EV deployment



Source: ZSW (2020).

Sales of FCEVs have been much lower than EV sales, with only 25 000 passenger vehicles on the road in 2020 (IEA, 2021). While the United States, Japan and China have led their deployment in the past few years, Korea became in the country with the largest FCEV stock in 2020 (29% of all FCEVs and 40% of passenger FCEVs). Despite the current market size, FCEVs could offer the advantages of a longer range and easier refuelling compared to EVs. As a result, they may be well suited to segments with intensive duty cycles, such as long-range and high-utilisation road vehicles like heavy-duty trucks and regional/intercity buses, trains, ferry boats and utilitarian vehicles such as forklifts, where today's batteries face limitations (IRENA, 2018b). Hydrogen should therefore be considered as complementary to BEVs in the broader context of the transport sector's energy transition. In fact, as Figure 7 (below) shows, clear competitive advantages for FCEVs and BEVs can be seen in each market segment. Hydrogen fuel cells are already beginning to be used for commercial rail services in Europe, for example, avoiding the high capital expense of installing overhead wires (IRENA, 2018b). In addition, renewably produced hydrogen and its derivative e-fuels have the potential to indirectly electrify the maritime and aviation sectors.

Figure 5 Segmentation of the transport market



Source: IRENA (2018b).

The market segmentation described above is changing, however, as battery technology improves and costs decline. In particular, electric trucks could achieve significant market share faster than expected, especially for short- to medium-distance trips such as those that dominate in Europe, where about half of freight transport trips are less than 300 km (Transport & Environment, 2017). In addition to a growing number of electric truck offerings from industry leaders, complementary innovative solutions such as "electric road systems" are already being demonstrated for freight transport in California, Germany and Sweden (Research Institutes of Sweden, 2019).

Direct electrification through battery-powered ships and aircraft is also being explored in the maritime and aviation sectors, similarly beginning with short- and medium-range transport. In Norway, for example, Avinor, the public operator of Norwegian airports, believes that all flights of less than 1.5 hours could be flown by electric aircraft, which would cover all domestic flights and those to neighbouring Scandinavian capitals (Avinor, 2018). Boats and ships in many major ports and harbours with "shore power" facilities already use grid electricity while docked to cut local pollution and fuel use. In addition, all-electric vessels, mainly short-distance ferries, are already in commercial use (Holter and Hodges, 2018).

Box 3. China case study – Electric transport in cities and ports

Driven by an urgent need to reduce air pollution, China's cities have quickly become global leaders in the electrification of transport. Shenzhen, for example, transitioned its entire fleet of buses – more than 16 000 – to electricity in less than five years, completing the process by 2017 (Lu, Xue and Zhou, 2018). Replacing the previous diesel buses cut emissions from transport by 20%, even though the diesel buses represented only about 0.5% of the city's total vehicle fleet. Shenzhen also transitioned 99% of the city's more than 21 000 taxis to battery power by 2019 (Liao, 2019), significantly cutting pollution because of the taxis' high utilisation.

Beijing is following the lessons learnt in Shenzhen, aiming to increase the share of electric buses in the city fleet to 60% by 2020. That will mean putting 10 000 electric buses into service, a tenfold increase from 2017 (China Daily, 2017). The Shenzhen-based EV manufacturer BYD is also beginning to export its successful experience worldwide, with orders to provide electric buses to cities in the United Kingdom, Chile and South Africa (Liao, 2019).

Progress towards greater electrification is also occurring in other transport areas in China. In its report "New Electricity Frontiers", the Global Sustainable Electricity Partnership notes:

"The share of electrified railways in China [is] about 40%. It is forecasted that this figure will increase to 60% in 2020 and 90% in 2050. Ships and boats in ports and harbors are encouraged to use electricity rather than diesel. In airports, all vehicles and equipment are encouraged to be driven by electricity. In 2017, State Grid built 44 high-voltage and 507 low-voltage power supply systems along the Beijing-Hangzhou Grand Canal, eastern coast and Yangtze River. 50% of ports along the Beijing-Hangzhou Grand Canal now are able to provide electricity supply." (GSEP, 2018)

Because of China's push to electrify vehicle transport and to develop more electrified railways and ports, China is among the few major countries and regions to show a substantial increase in the level of electrification in transport since 2000 (see Appendix I).

Transport: Key network and end-use infrastructure requirements and cost drivers

For the three key electrification routes in the transport sector, the unique network and end-use infrastructure needs are:

EVs:

- Manufacturing EVs.
- Installing charging infrastructure at a majority of parking locations (public and private).
- Installing smart meters to allow for smart charging (through price signals or demand-side management).
- Implementing eventual vehicle-to-grid (V2G) technology, if necessary.

FCEVs:

- Manufacturing FCEVs (mainly long-haul vehicles).
- Retrofitting petroleum T&D networks where possible for renewably produced hydrogen, and building dedicated T&D where necessary.

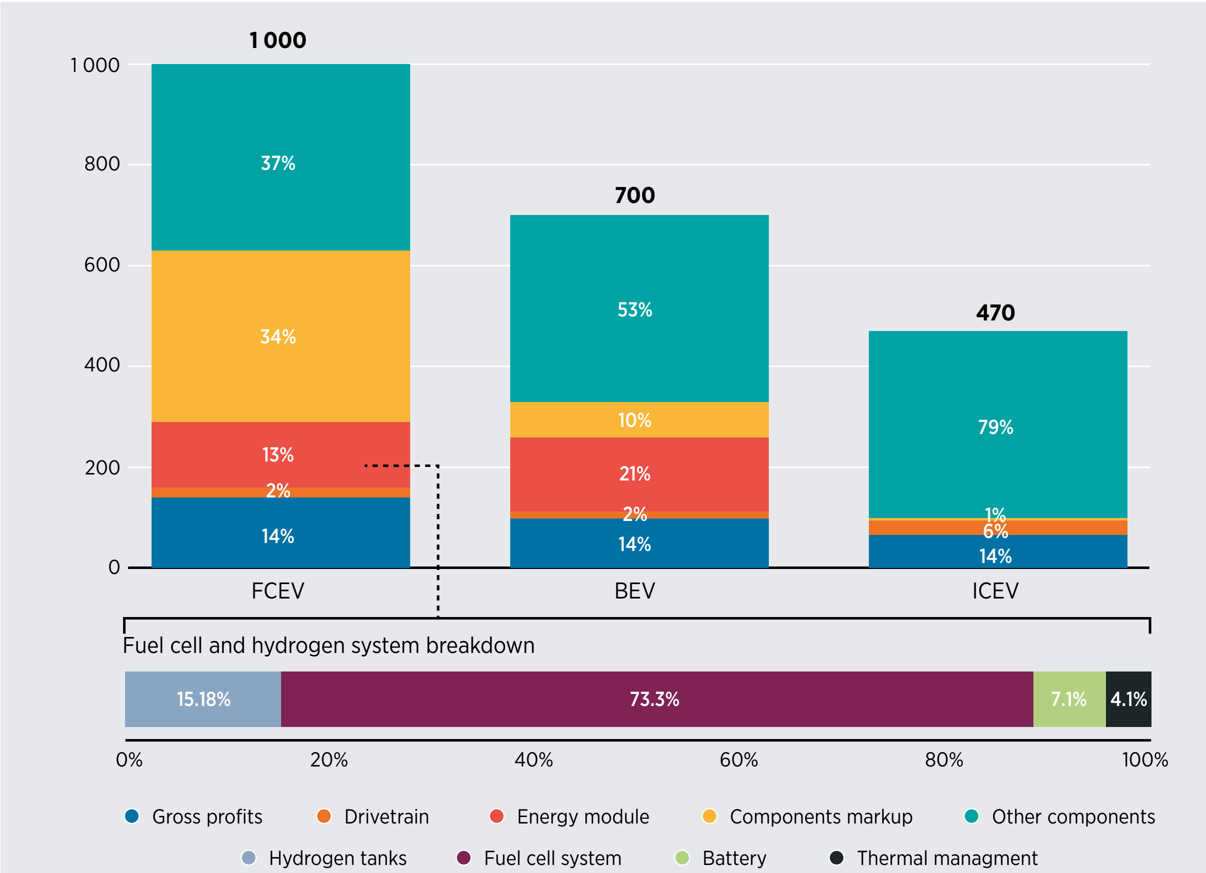
E-fuels:

- Beyond the need for e-fuel production, theoretically little need for new network and end-use infrastructure when used as direct (drop-in) replacement for fossil fuel.
- New T&D infrastructure and end-use technology manufacturing for e-fuels that may not be direct fossil-fuel replacements, such as ammonia for shipping.

One current barrier to greater electrification of transport is the relatively high up-front cost of electric road passenger vehicles. Vehicle costs are highly dependent on battery costs, however, and those are rapidly declining. The International Energy Agency has estimated that the cost of a battery pack was around USD 156/kWh in 2019, which is 87% lower than the average cost level in 2010 (IEA, 2020b). According to the annual Bloomberg New Energy Finance survey of battery prices, the cost of batteries in 2020 has further dropped by 13% compared with the previous year (BNEF, 2020). The average battery pack costs, estimated at USD 137/kWh in 2020, is expected to reach USD 100/kWh by 2023, making the total ownership cost (including installation of home charger) comparable to that of an internal combustion engine.

As reflected in their relatively lower sales, the up-front costs of passenger FCEVs are significantly higher than EVs at the moment. To illustrate the difference in cost components and levels, Figure 9 displays the breakdown of the purchase price of buses in the United States, comparing FCEVs, EVs and vehicles with an internal combustion engine. These component costs are location-specific – e.g. in China the FCEV purchase price is significantly lower at USD 314 000, due to much lower component and component markup costs (Deloitte, 2020).

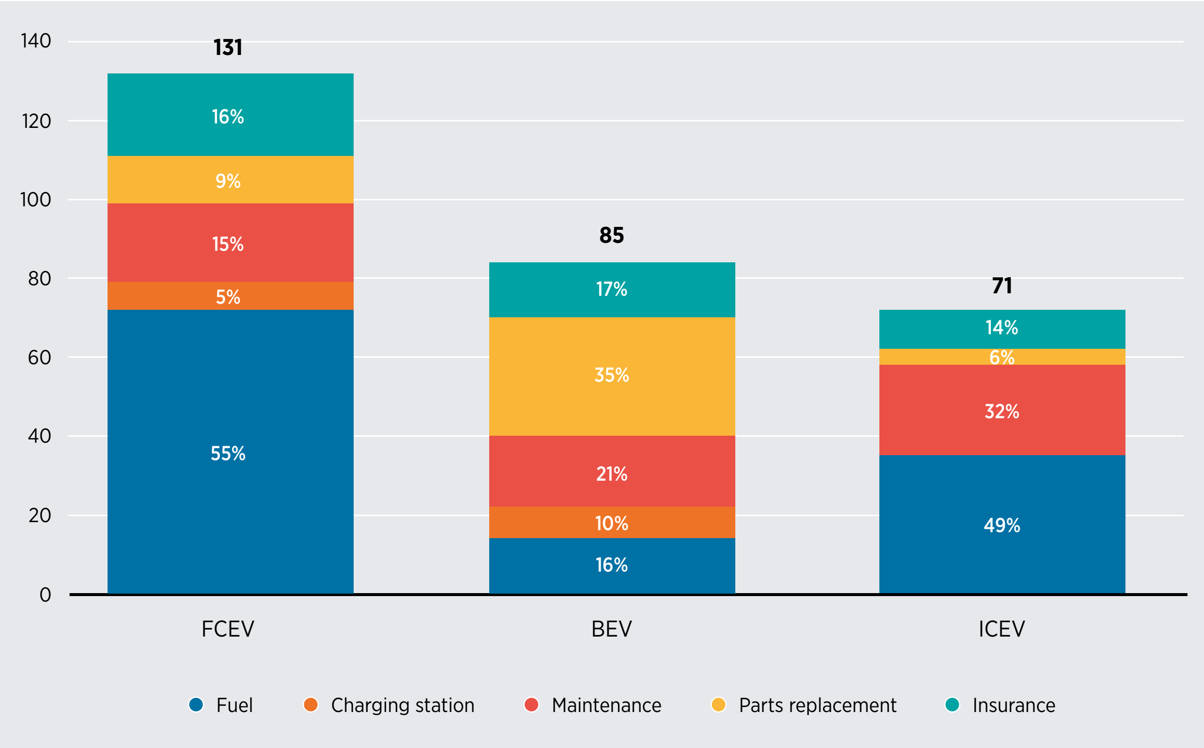
Figure 6 Breakdown of bus purchase price (USD 000/vehicle)



Note: ICEV = internal combustion engine vehicle.
Source: Deloitte (2020).

Both EVs and FCEVs also require infrastructure for electricity and fuel production, as well as recharging and refuelling infrastructure. Remaining with the illustrative example of a bus in the United States, the figure below levelises such infrastructure costs along with other key operational costs.

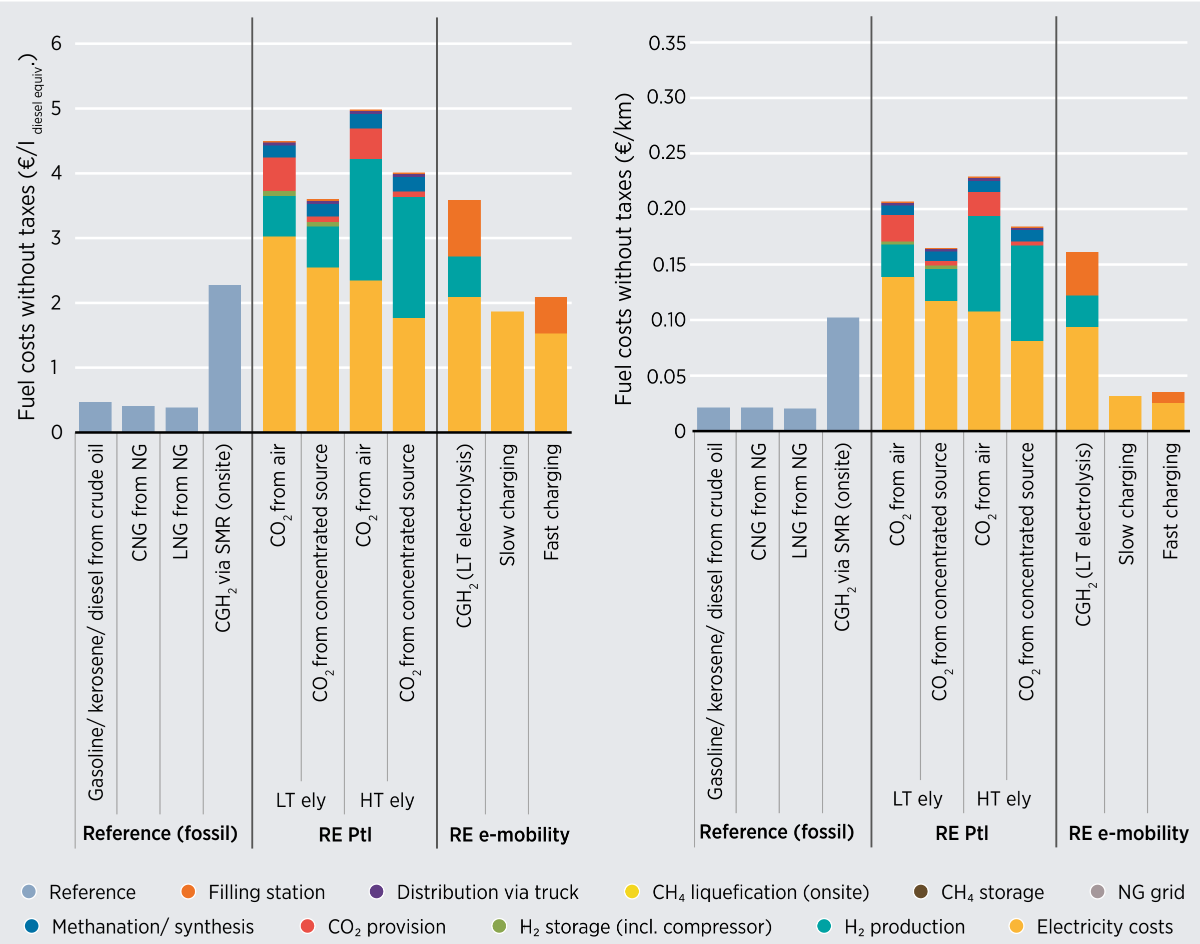
Figure 7 Breakdown of bus operational cost (USD 000/100 km)



Source: Deloitte (2020).

These wider infrastructure costs can also be captured in so-called well-to-tank measures, which compare costs of fuel production through to charging and fuelling network infrastructure. In an analysis for the European Union, Siegemund et al., (2017) estimate total wheel-to-tank costs for fast- and slow-charging EVs, FCEVs and e-fuel powered passenger vehicles (referred to as "PtL" or power-to-liquid). The figure below shows these costs, as well as their "well-to-wheel" extensions, which factor in the cost and efficiency of the vehicle itself along with charging and fuelling networks. While exact costs are rapidly evolving, the figure provides an illustrative view of the differing cost compositions for competing options. Note that electricity costs in the figure include T&D network requirements for each option, but that the need for distribution network upgrades due to EV charging is highly contingent on context and the extent to which storage and smart charging solutions are incorporated within charging network infrastructure (see Section 2.3 Smart electrification strategies - Vehicle transport for more detail on this issue).

Figure 8 Transport fuel costs: well-to-tank per unit of fuel volume (left) and well-to-wheel per unit of distance (right)



Notes: Left graph unit = EUR per litre of diesel equivalent; right graph unit = EUR per km; CGH_2 = compressed hydrogen; CNG = compressed natural gas; CH_4 = methane; H_2 = hydrogen; LNG = liquefied natural gas; LT = low temperature; HT = high temperature; NG = natural gas; SMR = steam methane reforming.
Source: Siegemund et al. (2017).

An important variable in EV charging infrastructure costs in the study relates to the assumptions surrounding "superchargers" and on-site stationary storage at fast-charging stations, as compared to home chargers and utility-scale storage assumed for slow charging in the study. Smart metering for home charging is relatively low cost in comparison to other infrastructure needs, at an estimate of USD 13 per year (EUR 11.77/yr) (Siegemund et al., 2017).

While e-fuels (and hydrogen to some extent) have the advantage of being able to use existing transport sector infrastructure for fuel delivery and use, it is clear that inputs into hydrogen and e-fuel production are the main drivers of their relatively higher cost estimates in passenger vehicles. For this reason, Box 4 takes a deeper look at hydrogen and e-fuel production costs as part of a cross-sector overview of Power-to-X infrastructure costs.

Although the actual costs of FCEV and e-fuel vehicles in other transport applications, such as long-haul shipping and aviation, are not available given the state of deployment, as mentioned previously their theoretical cost-benefit rations in those areas are more attractive due to the lack of options for direct electricity use (Perner, Unteutsch and Lövenich, 2018).

INDUSTRY

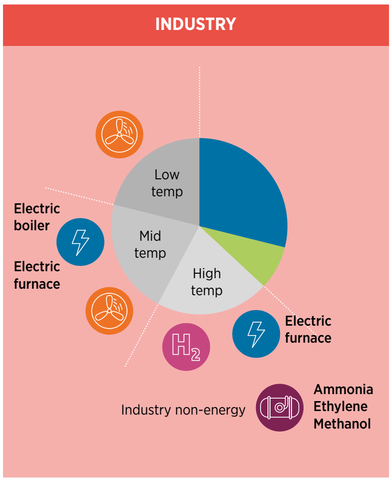
The total global final consumption of the industrial sector is 154 EJ, including 35 EJ for non-energy use (IEA, 2020a). About 28% of the 119 EJ consumed as energy was supplied from electricity. Four energy-intensive industrial commodities (cement, iron and steel, and chemical commodities ammonia and ethylene) alone account for about 60% of industrial energy use (McKinsey & Company, 2018). Non-energy use (e.g. direct use of fossil fuels as feedstocks for industrial processes) is entirely made up of fossil fuels, with 70% as a feedstock for ethylene production (using mainly oil) and the rest for methanol and ammonia production (using mainly natural gas) (ibid.).

The main technology options to achieve **electrification of industrial energy demand** as well as electrification of the non-energy use within the industrial sector are:

(1) Direct electrification of industrial heating processes using electric boilers and/or furnaces for medium- and high-temperature heat applications.

(2) Use of heat pumps, particularly for low-temperature, and potentially medium-temperature, heat applications.

(3) Using renewable electricity to produce hydrogen and/or its derivative e-fuels, particularly for high-grade heat and non-energy uses.



For the high temperatures (≥ 500°C) required in the production of cement, iron and steel, and chemical commodities (ammonia and ethylene), industrial-scale electric furnaces are now at the applied research and pilot phases for the cement and ethylene industries. The capital costs of these electric furnaces could eventually be similar to those of conventional furnaces (McKinsey & Company, 2018), although energy supply costs are the main determinant of viability. Deployment of such technologies could also entail significant retrofitting or other changes to existing production equipment, and even whole new industrial sites. Mature use of electricity to provide high-temperature heat is limited to certain industrial processes such as aluminium smelting and the use of electric arc furnaces in steel production.

For medium-temperature heat demand (200°C ≤ 500°C), electric and hybrid boilers have been applied at industrial-scale sites, and could act as replacements for gas- and coal-fired options (ibid.).

For low-temperature industrial heating, currently available heat pumps can supply temperatures of up to 100°C. Heat pumps that supply higher temperatures (≤ 150°C) are now at the research and development stage. Those higher temperatures would make expanded application of heat pumps possible, for example in the paper and food industries (European Heat Pump Association, 2019).

The levels of deployment and the technical maturity of these direct electrification options vary significantly across industrial sub-sectors. Currently, electric boilers, furnaces and heat pumps are largely limited to industry sectors outside the four main industrial commodities (cement, iron and steel, and chemical commodities ammonia and ethylene) (McKinsey & Company, 2018). In those other industry sectors, such as manufacturing, food production and pulp and paper production[7] (which make up about 40% of industrial energy use), electrical end-use technologies are commercially proven solutions for low-to medium-temperature heat, although their application is far less common than the prevalent fossil fuel-fired heating solutions (ibid.).

Industrial use of hydrogen produced from renewables is an important alternative electrification option beyond the expansion of direct electrification and heat pumps, but is mainly at the research and development or pilot stages for different industries. In the short term, large industrial sectors where hydrogen (produced from fossil fuels) has been used for decades as a feedstock – largely in the production of ammonia and oil refining – are expected to be key early markets. Increased use in these markets could then generate economies of scale and cost reductions, enabling more widespread production and use of renewables-based hydrogen (IRENA, 2018b). Depending on the cost evolution of direct electrification technologies for high-temperature heat demand, hydrogen-fuelled furnaces could be an option to displace conventional fuels in process heat demand at or above 500°C across the cement, iron and steel, and chemical sectors (ibid.).[8]

Industry: Key network and end-use infrastructure requirements and cost drivers

The main network and end-use infrastructure needs for **the electrification of industry** include:

- Manufacturing electric boilers[9] and/or furnaces.
- Manufacturing heat pumps.
- New or retrofitted industrial processes or plants for electricity use.
- New or retrofitted industrial processes or plants for renewable hydrogen and/or e-fuels as fuel or feedstock.

As mentioned earlier, both electric boilers and heat pumps are already commercially available substitutes for their fossil-fuelled alternatives in many industrial applications of low- and medium-temperature heat, often improving quality and efficiency (IEA, 2017). Experience with these has shown that the capital costs of electric and conventional end-use equipment are not nearly as influential on rates of adoption as operational costs, however. As a result, in most cases the main cost driver behind actual deployment is ultimately the spread between electricity and natural gas prices (McKinsey & Company, 2018).

The same cost dynamic is expected to be at play for technologies and processes that have not yet reached large-scale commercial application, such as high-temperature electric furnaces and replacement of fuels or feedstock with hydrogen in cement, iron and steel, and chemical sectors. Given the input-intensive nature of these applications, the cost of electricity will be a key determinant of competitiveness. However, the existing end-use infrastructure in these hard-to-decarbonise sub-sectors typically has a long lifetime, meaning the difference between retrofitting existing sites and processes (i.e. brownfield installation) and simply building new industrial sites (i.e. greenfield installation) will also be an important cost driver.

7 The more comprehensive list includes food and tobacco, construction, mining, machinery, non-ferrous metals, paper and pulp, transport equipment, textiles and leather, wood and miscellaneous industry.

8 Section 2.4 discusses the system-wide infrastructure implications of these competing electrification pathways in more detail. It should be noted that alternative decarbonisation options in this sector must also be considered – for example, using biofuels as a fuel is a mature technology and is typically deployable with modest alteration of process design. In areas where sustainable biofuels are available, they may be financially more attractive options. Geothermal heat is another complementary option for areas where such resource is available. Finally, in regions and industrial locations with sufficient space, CSP may be deployed.

9 Including electrode and medium-voltage 4 kV boilers.

While individual site and process characteristics will differ, Table 2 shows the results of a study by McKinsey & Company (2018), which attempts to take these various cost drivers into account. It identifies generic stages of low-priced zero-carbon electricity at which electrification becomes more economic than carbon capture and storage (CCS) (chosen as the most likely decarbonisation alternative). While these generic stages are helpful, they should be treated as conceptual, as they reflect a wide range of assumptions regarding complex value chains and processes, particularly surrounding the costs of hydrogen infrastructure. More detail on the range of projections for hydrogen and other Power-to-X infrastructure costs can be found in Box 4.

Table 2 Indicative stages at which different industrial electrification solutions become more economic than CCS in major industrial end uses

Stages of low electricity prices	Key changes in the cost-competitiveness of industrial electrification solutions
First stage of low electricity prices	Electrifying heat production at greenfield cement plants is more cost-competitive than applying CCS to the emissions from fuel consumption, provided that very-high-temperature electric furnaces are available.
Second stage of low electricity prices	Hydrogen use for greenfield ammonia and steel production sites is more cost-competitive than applying CCS to conventional production processes.
Third stage of low electricity prices	Electrification of heat in greenfield ethylene production and in brownfield cement production and usage of hydrogen for brownfield steel production are more cost-competitive than applying CCS to conventional production processes.
Fourth stage of low electricity prices	Usage of hydrogen for brownfield ammonia production and electrification of heat for ethylene production are more cost-competitive than applying CCS to conventional production processes. Essentially, electric heat production and usage of electricity to make hydrogen are more economical approaches to decarbonisation than CCS in all four major industry sectors – cement, iron and steel, ammonia and ethylene – at this electricity price level.

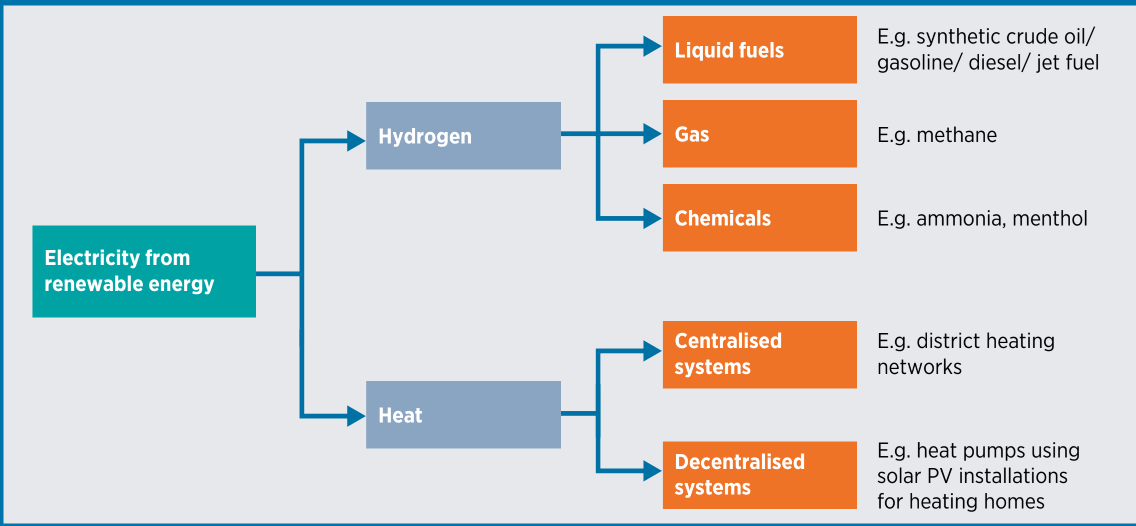
Note: In the original source, these stages correspond to the following electricity prices: below ~USD 50/MWh; below ~USD 35/MWh; below ~USD 25/MWh; and below ~USD 15/MWh. The descriptive text remains the same as the source, but the adapted table instead presents generic categories to reflect the fact that the exact price levels at which the indicative technological competitiveness changes occur are highly sensitive to assumptions.
Source: Adapted from McKinsey & Company (2018).

Box 4. Power-to-X: Hydrogen and electrofuel technologies, trends and cost drivers

Power-to-X definition

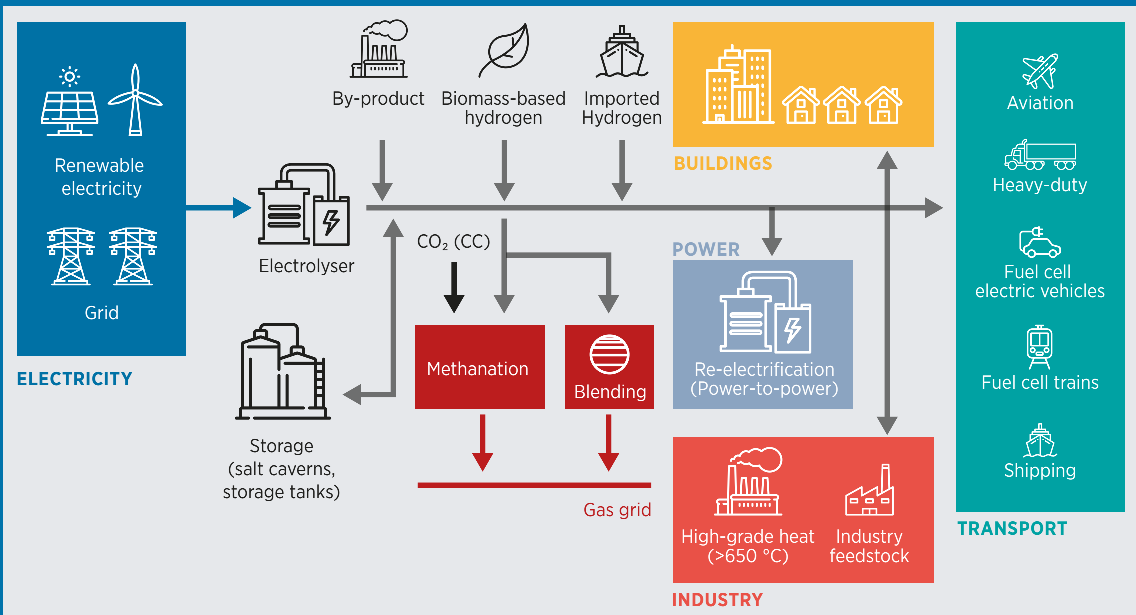
In addition to being used directly to power everything from vehicles to appliances, electricity can be converted into other types of energy carriers, such as heat or hydrogen, in what is known as Power-to-X.

Figure 9 Classification of **Power-to-X technologies**



While power-to-heat is used for typical heating solutions in buildings and industry, power-to-hydrogen has more varied end-use cases, as seen below.

Figure 10 Integration of VRE into end uses by means of hydrogen



Source: IRENA (2018b).

In the literature, the further production of gaseous or liquid energy carriers or feedstocks based on hydrogen has been called “Power-to-Gas/Liquid” (P2G/PtL), “synthetic fuels”, “electrofuels/e-fuels”, and “powerfuels”. This report uses the most common term, electrofuels, or e-fuels for short. Although e-fuels require further costly processing, a climate-neutral CO_2 source, and entail further efficiency losses, they also have benefits from easier storage than hydrogen, easier integration with existing infrastructure and the ability to enter unique markets.

Key infrastructure requirements and cost drivers

The total cost of hydrogen infrastructure is made up of two high-level elements: production and logistics (i.e. the transmission, distribution and storage network).

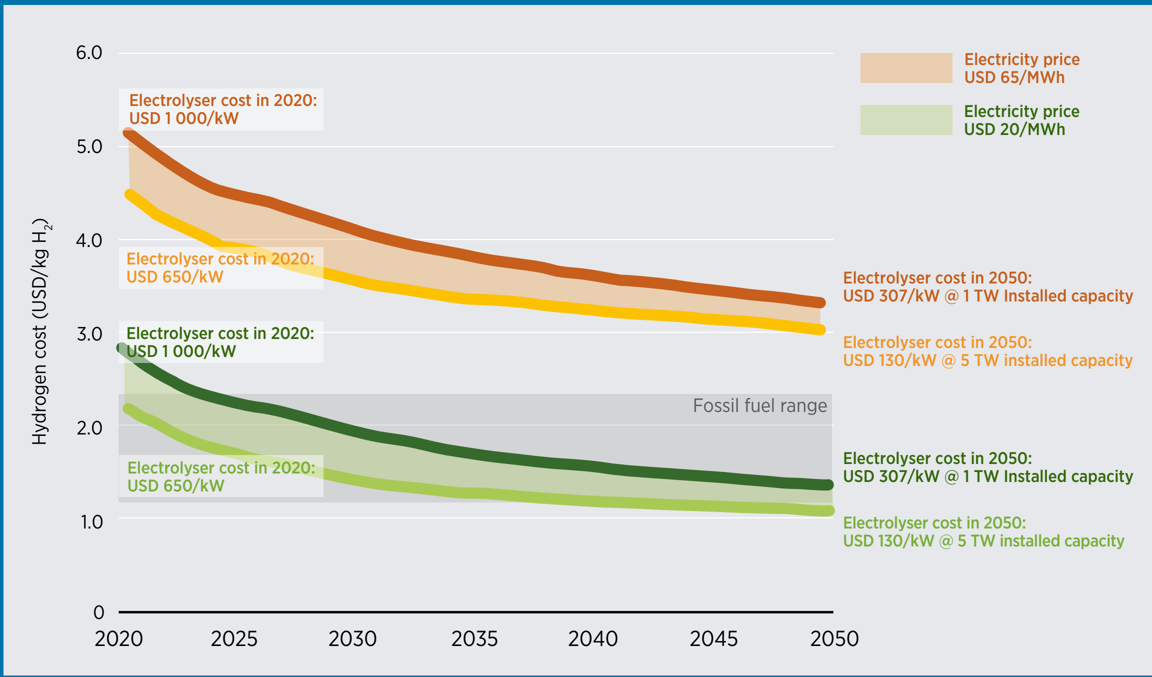
As for production, three main parameters are critical for the economic viability of hydrogen production from renewables: the cost of the renewable electricity to be used in the process (the LCOE), the electrolyser capital expenditure and the number of operating hours (load factor) on a yearly basis.

Regarding renewable electricity, utility-scale solar PV and onshore wind have reached cost levels of 2-3 US cents per kWh in an increasing number of locations; in 2020 the average electricity cost from utility-scale solar PV fell 7% year-on-year, with onshore and offshore wind falling by 13% and 9% respectively (IRENA, 2021c). Electrolyser capital costs are also falling, albeit less rapidly, from today’s cost range of USD 500-1 400/kW, depending on the technology, to an expected level of less than USD 200/kW by 2050 (IRENA, 2020e).

The higher the electrolyser load factor, the cheaper the cost of one unit of hydrogen. Electrolyser load factors should in general exceed 50% at today’s investment cost levels, but nearly optimal hydrogen costs start being achieved at over 35%. This percentage will drop as electrolysers become cheaper. Solar-wind hybrid systems appear to be a promising solution and could achieve capacity factors well above 50% in places such as the Atacama Desert in Chile where they complement each other’s availability. Considering all of these production cost elements, Figure 16 below shows the average and best-case supply costs of renewable electricity today, compared to the supply from fossil fuels with CCS. The data suggest that CO_2-free renewables could be among the cheapest hydrogen sources even today, although only in very particular situations.

With the expected decrease in both electrolyser costs and renewable electricity costs in the long run, the electrolyser load factor will play a smaller role, and hydrogen from renewable power is anticipated to become competitive with or cheaper than all forms of producing hydrogen from fossil fuels (IRENA, 2019c).

Figure 11 Cost of green hydrogen production as a function of electrolyser deployment



Note: Efficiency at nominal capacity is 65%, with a LHV of 51.2 kilowatt hour/kilogramme of hydrogen (kWh/kg H_2) in 2020 and 76% (at an LHV of 43.8 kWh/kg H_2) in 2050, a discount rate of 8% and a stack lifetime of 80 000 hours. The electrolyser investment cost for 2020 is USD 650-1 000/kW. Electrolyser costs reach USD 130-307/kW as a result of 1-5 TW of capacity deployed by 2050.
Source: IRENA (2020e).

In addition to production costs, the use of hydrogen requires transmission, distribution and storage, which could be capital intensive. The total cost of fossil fuel-produced hydrogen is currently in the range of two or three times higher than the production cost alone. Realistically, the hydrogen supply chain is expected to ramp up in stages, from on-site production to centralised and even potentially intercontinental supply chains. Initial steps leverage existing gas grids, which entails retrofit costs before any potential conversion to full hydrogen grid infrastructure with investment in conditioning and filling centres. This staged approach, along with the fact that multiple potential delivery methods exist – e.g. through compression, liquefaction, or embedded in energy carriers such as ammonia, methanol and other liquid organic hydrogen carriers – makes the cost of hydrogen network infrastructure highly speculative and dependent on regional investment decisions. Further experience is needed to reveal more detail on the true costs.

The further conversion processes of hydrogen into what could be considered the four main e-fuels – ammonia, methanol, synthetic methane and synthetic oil products – are at different stages of commercial deployment today. Table 3 below shows IRENA production cost estimates for these fuels.

Table 3 E-fuel production cost estimates

Synthetic fuels	Total production cost (USD/GJ)	Fossil-based product price (USD/GJ)
Ammonia	27-32	11-19
Methanol	24	15-18
Methane	28	10-16
Synthetic oil products	23	12-18

Source: Adapted from IRENA (2020c).

Ammonia is already a global commodity; however, the hydrogen used for ammonia production is produced from natural gas or coal. Given that ammonia is consumed on a large scale as a feedstock, future renewable hydrogen can be supplied to meet existing demand, using existing supply chain and logistics. The current cost gap between ammonia production with renewable hydrogen and with fossil fuels is the lowest among the e-fuels considered.

Methanol is also currently produced at scale from a mixture of hydrogen and carbon monoxide, which themselves are produced from natural gas or coal. Methanol from renewables also has a limited cost gap with its fossil-based counterpart and is experiencing growth in demand.

Synthetic liquid production from syngas (hydrogen/CO/CO_2 mixture) is a proven technology and is applied on a commercial scale in South Africa, where coal is used as feedstock.

Today the cost gap between synthetic methane and natural gas is the largest among the e-fuels, although there is potential for improvement if the cost of the CO_2 from direct air capture drops significantly. Synthetic natural gas can also benefit from natural gas infrastructure as well as from a strong and growing LNG industry. It can be used directly in existing infrastructure as well as in appliances, including for power generation and heating.

To complement IRENA estimates, Table 7 and Table 8 in Appendix II show additional ranges of estimated costs to produce synthetic renewable methane and synthetic oil. For synthetic methane, estimates vary considerably in part due to the wide range of assumptions for the cost of CO_2 feedstock, USD 34-350/tonne.

Given the potential need for renewables-based e-fuels in sectors where no viable decarbonisation alternatives exist, such as the aviation, shipping, chemical and petrochemical sectors, the higher costs relative to their fossil-fuel counterparts should not prevent further research, development and deployment. As discussed in Chapter 4, this rather calls for supportive policies to explore the significant cost reduction potential that exists for these technologies.

2.3 SMART ELECTRIFICATION STRATEGIES

A successful energy transition requires much more than simply building large numbers of wind and solar plants, switching to EVs and heat pumps, remaking industrial processes to use renewably produced fuels, and investing in the many other technologies and basic infrastructure needed to electrify as much of the economy as possible. It also requires whole new strategies and careful planning to integrate all these technologies and devices, and to manage the huge and rapidly varying amounts of electric power flowing in many directions around the transmission grids – without causing crippling problems like overloaded distribution networks due to rising peak demand. The energy transition to an electrified economy will dramatically increase the existing challenge of matching electricity supply and demand, given both the enormous increases in demand and the variable nature of power generation from renewable sources like wind and solar.

Fortunately, this challenge can be met through what this report calls "smart electrification". Using a combination of smart digital infrastructure, market design, regulatory frameworks and business models for advanced control, it will be possible, for example, to significantly reduce peak loads and shift the timing of electricity use to periods when generation is high or when demand had previously been low.

Such smart approaches are in fact a prerequisite for the electrification pathways discussed earlier in this chapter. They are vital to enable intelligent grid expansion and management, such as shifting demand to better match the variable generation of electricity from renewables, thus avoiding issues of grid congestion and renewable curtailment. But they do much more than simply solve problems. By making it possible to integrate and utilise greater amounts of low-cost renewable electricity, they also create new opportunities to electrify even more end uses, from trucks and ships to steelmaking, kicking off a virtuous cycle that accelerates the growth of both renewable energy and the electrification of the economy.

This section discusses the major smart electrification strategies needed to achieve this virtuous cycle, for both direct and indirect electrification. These strategies broadly fall into three categories, described below, and can effectively solve the problems that would be caused by poorly planned electrification in all three of the major sectors – transport, buildings and industry.

Better matching demand with electricity supply

Renewable electricity generation can change within minutes when wind speeds slow or clouds reduce solar radiation, increasing the challenges of matching supply with demand. If energy production drops when demand is still high, alternative sources may be needed fill the gap. Or if demand is low when energy production is high, valuable electricity generation will be wasted. An effective strategy would go beyond merely reducing demand peaks to actually shifting demand to match the VRE production. It would also adjust the supply of energy to better match demand by using storage.

Expanding grid services

Renewable energy generation is far more variable, distributed and independent than centralised power plants. As a result, it requires many more grid services, such as load following, frequency regulation, black-start capabilities and provision of operational reserves in order to maximise the utilisation of the VRE. Many technologies now are available to provide these services, helping to accelerate the adoption of renewable energy generation.

Expanding opportunities for electrification

In addition to the strategies for enabling the integration of more renewable energy, other strategies take advantage of the unique characteristics of renewable electricity to meet new types of demand, such as hydrogen production.

DIRECT ELECTRIFICATION – SMART ELECTRIFICATION STRATEGIES TO MEET NEW CHALLENGES

This section describes smart electrification strategies that can reduce or prevent possible negative impacts from the direct electrification of transport, heating and cooling on the power system.

Vehicle transport

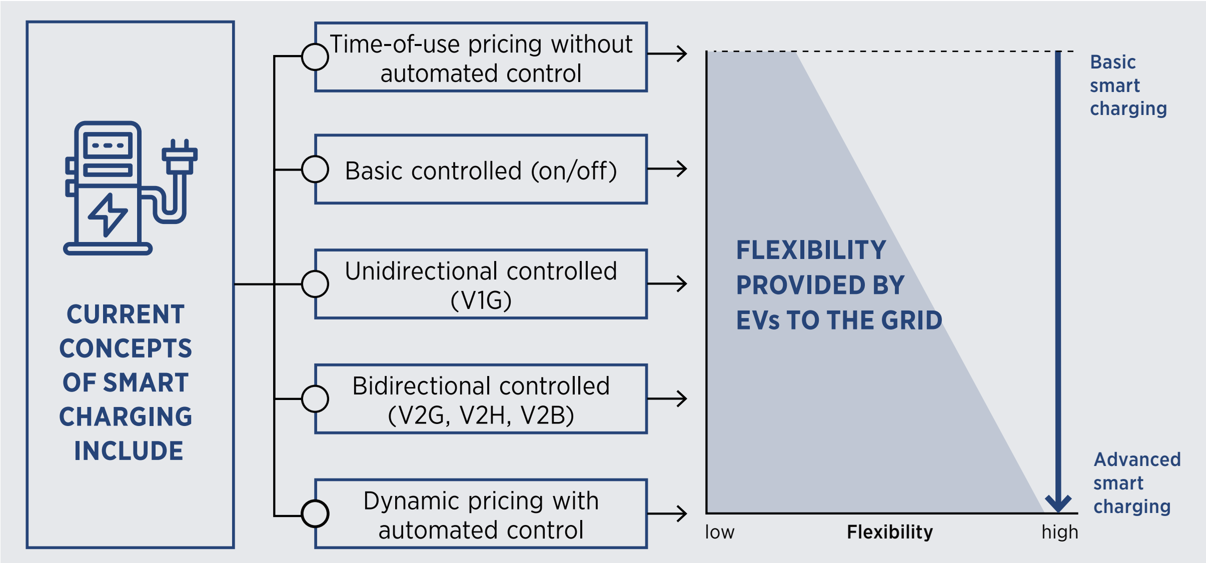
Rapid increases in the numbers of EVs could cause serious problems for today's power systems. For example, many people are likely to plug in their EVs when they come home from work in the evening, a time when demand already peaks. In some parts of the United States, for example, plugging in an EV could be the equivalent of adding multiple households to the grid (Bullis, 2013). That could overload local distribution networks (Lacey et al., 2013; Lillebo, 2018) and require greater investment in peak generation and transmission capacity (Engel et al., 2018; IRENA, 2019f). The problem will only worsen as EVs increasingly come equipped with larger batteries and faster charging capabilities.

Not only can these problems can be solved with smart charging approaches, but EVs can also actually bring new opportunities and important benefits to the electricity grid, because of the services that plugged in vehicles can provide, as the next two sections explain.

Smart charging to enable improved matching of supply and demand

Smart charging makes it possible to manage the timing of the additional loads caused by plugging in EVs, thus reducing or altogether avoiding issues like increases in peak demand. Some smart charging approaches are simple, such as lowering prices of off-peak electricity to provide incentives for consumers to defer their charging from peak to off-peak periods. Other approaches are more complex, such as automated real-time control over the rate and/or direction of charging, so that plugged-in vehicles are able to supply power back to the grid or owner's house to meet sudden demand peaks in what is known as vehicle-to-grid (V2G) strategies. Both these approaches are being made possible by ICT that enables owners to programme when they will need to use their vehicles, and then to take advantage of price signals or to meet utility needs (IRENA, 2019f). Given that personal cars are parked on average up to 95% of the time (Schmitt, 2016), parked EVs offer significant demand flexibility (as long as they do not sacrifice the warranty of their battery systems), and could therefore reduce system costs by making the most of VRE capacity. Less power capacity investment is needed if smart charging can reduce curtailment and increase self-consumption of decentralised on-site power (e.g. rooftop solar PV).

Figure 12 How smart charging enables EVs to provide flexibility



Source: IRENA (2019h).

Smart charging strategies can also limit or eliminate the need to upgrade or reinforce the existing T&D grid infrastructure. For example, a recent pilot project in the United Kingdom using more than 200 EVs (Nissan Leaf models) showed that a smart charging strategy could save up to USD 3 billion in grid reinforcement costs by 2050 (My Electric Avenue, n.d.). A wide range of additional studies, summarised in Appendix III, agree with the general conclusion that smart charging approaches can minimise the need for major grid investment or reinforcement, although the results for specific distribution networks may vary according to the network and the level of charging (Awadallah, Venkatesh and Singh, 2017).

Box 5. Smart EV charging network development in China

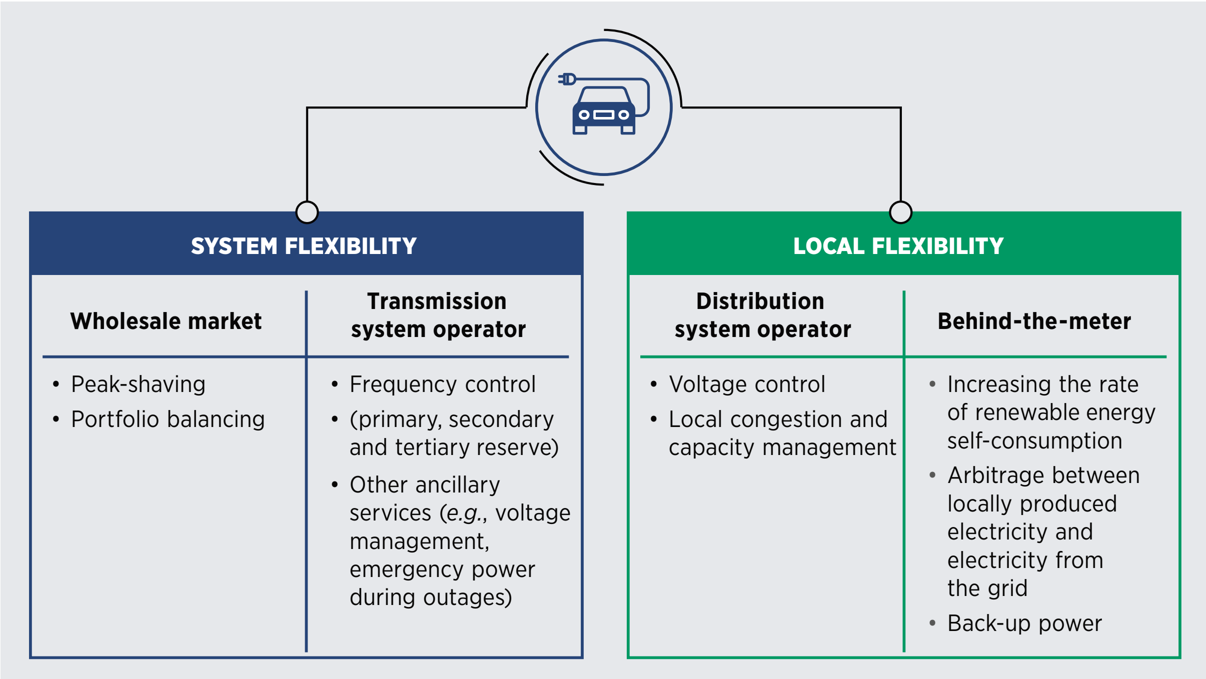
China has made significant network investment to facilitate the smart charging of EVs. In its report "New Electricity Frontiers", the Global Sustainable Electricity Partnership notes:

"By the end of 2017, China had over 450 000 charging stations, a 14-fold increase since the end of 2014. As the leader in China's EV development, the State Grid implemented the Smart EV-to-Grid Service Network (SEGSN), providing an EV charging service and charging station information. Moreover, SEGSN also provides EV sales and rentals, EV insurance and finance and charging station maintenance. SEGSN is the information hub for EV drivers, electricity grids and charging station operators, facilitating efficient communication among EVs, stations and grids and contributing to the foundation of a smart EV ecosystem. SEGSN now covers 19 provinces and 150 cities. It also provides charging services along over 310 000 km of highways, at intervals of less than 50 km. By the end of 2017, 170 000 charging posts were connected and over 800 000 consumers registered. In 2017, electricity consumption from EV charging in SEGSN reached 390 GWh, of which about 100 GWh was during off-peak periods, accounting for 26% of the total. SEGSN is capable of real-time operation monitoring and efficient maintenance: 90% of faults are fixed in one hour and the availability of charging stations is as high as 99%." (GSEP, 2018).

Plugged-in vehicles to offer important grid services

When EVs are parked and connected to grid, their batteries can provide a broad range of important services to the system. For example, power from EV batteries can help regulate both voltage and frequency on the grid, and can significantly reduce the need to ramp up expensive generating capacity to meet demand peaks (IRENA, 2019f). Fast chargers may also offer voltage stabilising services by injecting reactive power (Knezović and Marinelli, 2016). These services can improve the integration of renewables at both system and local levels for T&D system operators.

Figure 13 Services that EVs can provide to the power system



Source: IRENA (2019h).

It should be noted, however, that using large groups of EVs as a large-scale storage option may be less attractive than dedicated storage systems, given the latter's size and efficiency advantages. The additional wear and tear on EV batteries, if significant, may also limit their storage potential (Kasten et al., 2016). In addition, in the long run, autonomous and shared driving could increase the overall usage rate of vehicles, potentially limiting the scale of V2G service applications (IRENA, 2019f).

Heating and cooling

Like the electrification of transport, the direct electrification of heating and cooling, using heat pumps, electric heaters and boilers and other equipment, can potentially strain power systems due to new and higher demand for electricity. For example, the electrification of residential space and water heating and cooling increases existing evening power demand. As a result, the uncoordinated electrification of such end uses could negatively affect distribution networks and could require peak capacity investment.

Commercial and industrial heating and cooling, with typical use times in the morning and afternoon, may pose fewer short-term concerns about adding to peak loads, but could still have significant impacts.

What is unique about the electrification of heating and cooling is that in addition to the potential day-to-day impacts on the power system, it can also have major seasonal impacts. Switching from fossil fuel heating to electricity significantly increases demand during the winter in colder climates, while adding electric air-conditioning systems in many warm countries brings much higher peaks in summer demand.

All of these new challenges can be met, however, with a variety of smart electrification strategies, ranging from varying electricity prices depending on the time of day and smart control devices, to the storage of heat or cold over both the short and long term. Moreover, these strategies also provide grid services and can aid the integration of large amounts of VRE because they offer the ability to rapidly adjust heating or cooling demand to match the supply of electricity.

Smart heating and cooling to adjust demand to respond to short-term changes in supply

Smart heating and cooling systems are similar to approaches already described for transport. Simple time-of-use tariffs can provide incentives for consumers to defer their heating and cooling demands from peak to off-peak periods, for example, while automated real-time control using digital technologies over the timing of heating and cooling can quickly adjust demand to better match supply.

In buildings, heat pumps connected to smart electricity meters, thermostats and building management systems can serve as distributed heating loads to participate in demand response programmes. In commercial cooling, there are opportunities to boost overall system efficiency by capturing currently wasted heat, such as the excess heat generated by refrigeration systems in supermarkets. That heat can be used for space and water heating, or can be distributed to local thermal grids (Fischer and Laisi, 2019).

The benefits from these smart solutions can be amplified with the addition of thermal storage, allowing heating and cooling demand to be shifted to periods of greater electricity supply. Thermal storage can take different forms, including water, phase-change materials, building cores and the ground (Nowak, 2018). Thermal storage technologies already are in use, especially in modern co-generation and district heating and cooling systems, to improve flexibility (IRENA, 2020f, 2017).

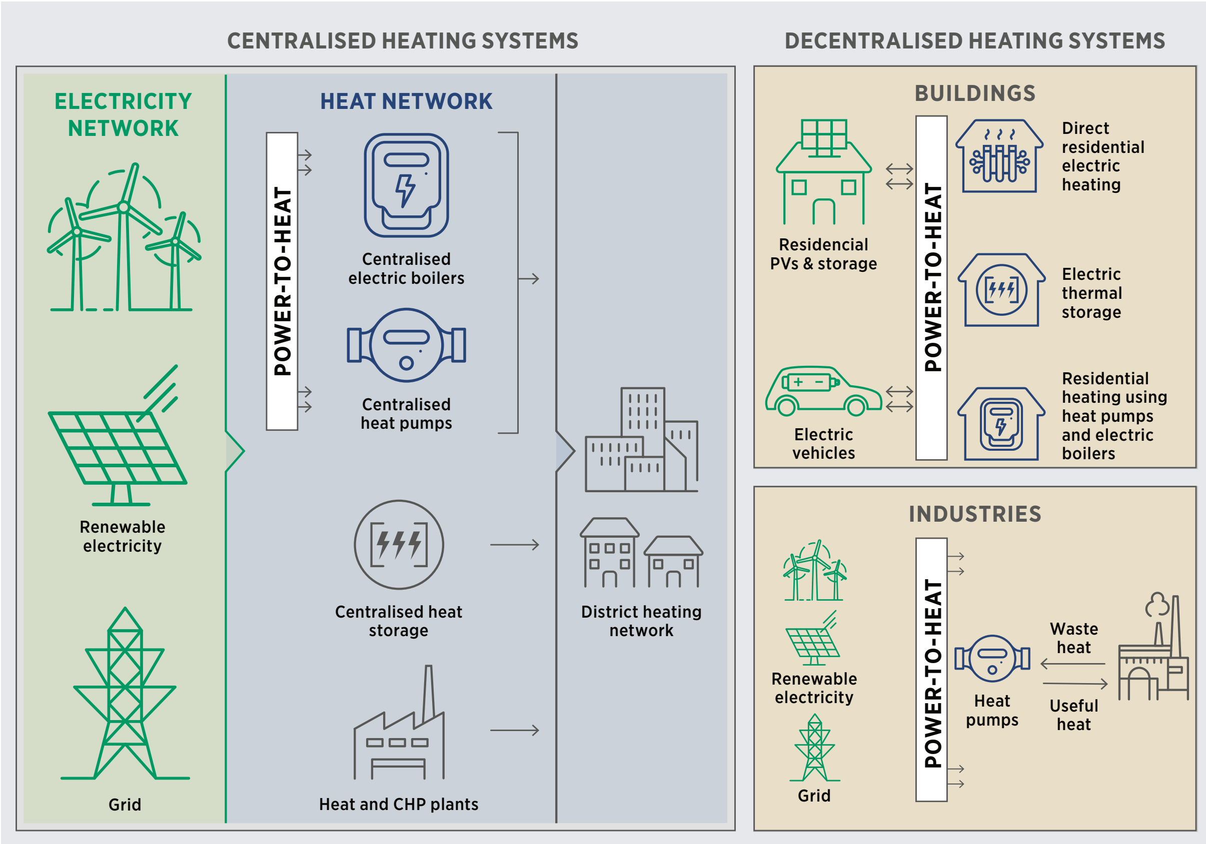
For industrial heating and cooling, many processes can be stopped or started, or ramped up and down, to better match electricity supply or to take advantage of fluctuating electricity prices (den Ouden et al., 2017).[10] For example, hybrid boilers can instantly switch between electricity and natural gas to lower costs and balance markets (McKinsey & Company, 2018).

These smart electrification strategies can offer major benefits by reducing peak electricity demand and lowering overall costs.

10 It should be noted there are other opportunities for smart electrification of industry beyond heating and cooling processes, such as control of electrolysis for hydrogen or synthetic feedstock (e.g. ammonia) production.

These strategies are also compatible with the full range of heating system configurations, from the more centralised to decentralised, as shown in Figure 21. In centralised heating systems, the development of smart thermal grids could also emerge as a key enabler of electric heating and cooling demand flexibility. Similar to smart electricity grids, smart thermal grids allow for an optimised (and possibly bidirectional) exchange of heat between the central network and individual customers via smart metering and communication devices, thus smoothing peak heat demands through increased flexibility and improving overall system efficiency (ERKC, 2014; Stănişteanu, 2017).[11]

Figure 14 Types of heating systems that use electricity



CHP = combined heat and power; PV=photovoltaic
Source: IRENA (2019i).

11 *ERKC (2014) lists research projects aimed at developing smart thermal grids that integrate CHP, storage and ICT, and which interface with other networks (power, gas, waste water etc.).*

Box 6. Data centre electrification

Demand for data centre services has risen steadily in recent years, and is forecast to continue its rise alongside the expansion of digitalisation and internet use (IEA, 2019c). While electricity demand for such services could become more significant in the future, efficiency measures and smart electrification have placed downward pressure on the sector's growth in demand for electricity.

For example, Google's DeepMind AI reduced the energy used for cooling at one of the company's data centres by 40% (a 15% overall reduction in power usage), using only historical data collected from sensors and applying a machine-learning algorithm to predict the future temperature and pressure of the data centre and to optimise efficiency (Evans and Gao, 2016).

At the same time, these services are being located in and relocated to areas with low-cost renewable electricity. For example, Facebook data centres in Denmark and Sweden take advantage of both hydro and wind power, while also using that renewable electricity for heat pumps to recover the centres' waste heat and recycle it for local community demand (Facebook, 2018).

Smart seasonal thermal storage to help manage higher seasonal peaks in demand

The electrification of heating and cooling can raise existing winter peaks for heating buildings and summer peaks for cooling, depending on the climate. Even though electrification reduces the overall amount of primary energy required, due to efficiency gains, these higher seasonal peaks can raise serious concerns about the adequacy of the power system or the need for more investment.

A detailed study of global residential heat demand (Fawcett, Layberry and Eyre, 2014) showed, for example, that using only air source heat pumps to meet that demand would significantly increase peak electricity demand compared to mean electricity demand. The calculated peak to mean ratios (Table 4) are well beyond the typical range in current power systems (which averaged at, for example, about 1.5 in the United Kingdom during 2010-2018 (BEIS, 2019b)), even when the highest 5% of peak times are excluded from the calculation.

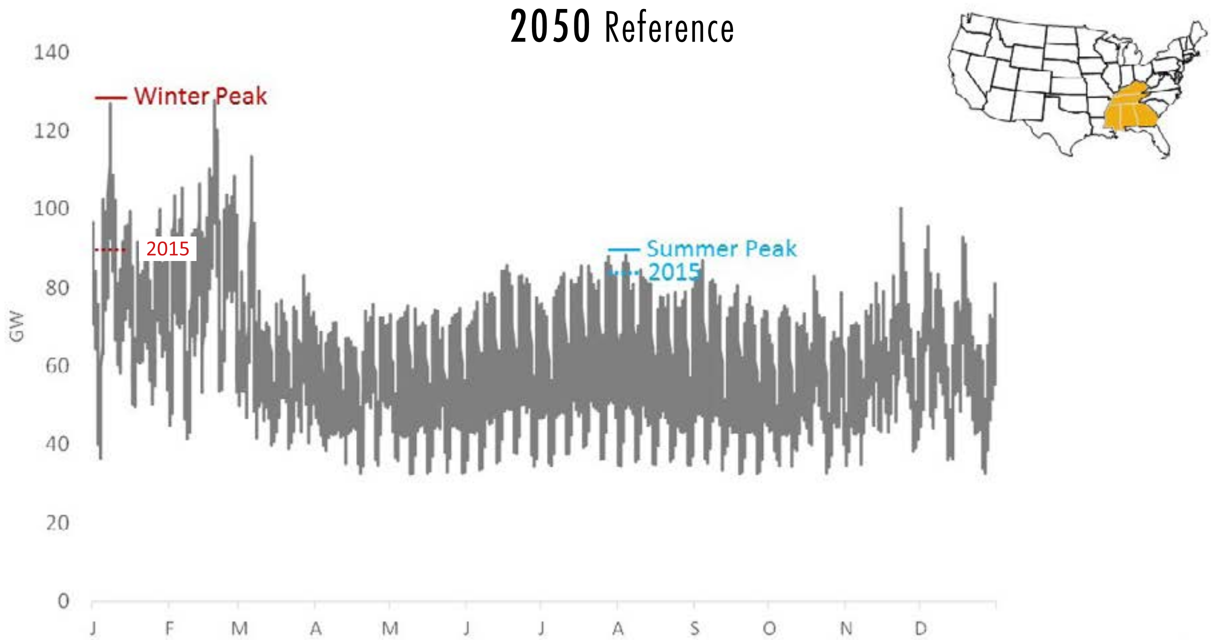
Table 4 Modelled ratio of annual peak electricity demand to annual mean electricity demand for residential heat, with all demand met by air source heat pumps

	United Kingdom	China	World
Peak to mean ratio	4.1	5	5.7
Peak to mean ratio for 95th percentile of heat demand	2.7	3.4	3.5

Source: Fawcett, Layberry and Eyre (2014).

Similarly, modelling of the Southeast region of the United States shows a potential 150% increase in the winter demand peak with greater electrification and no active management of loads, compared to 2015 levels (EPRI, 2018).

Figure 15 Electricity demand in EPRI 2050 Reference scenario for the Southeast United States



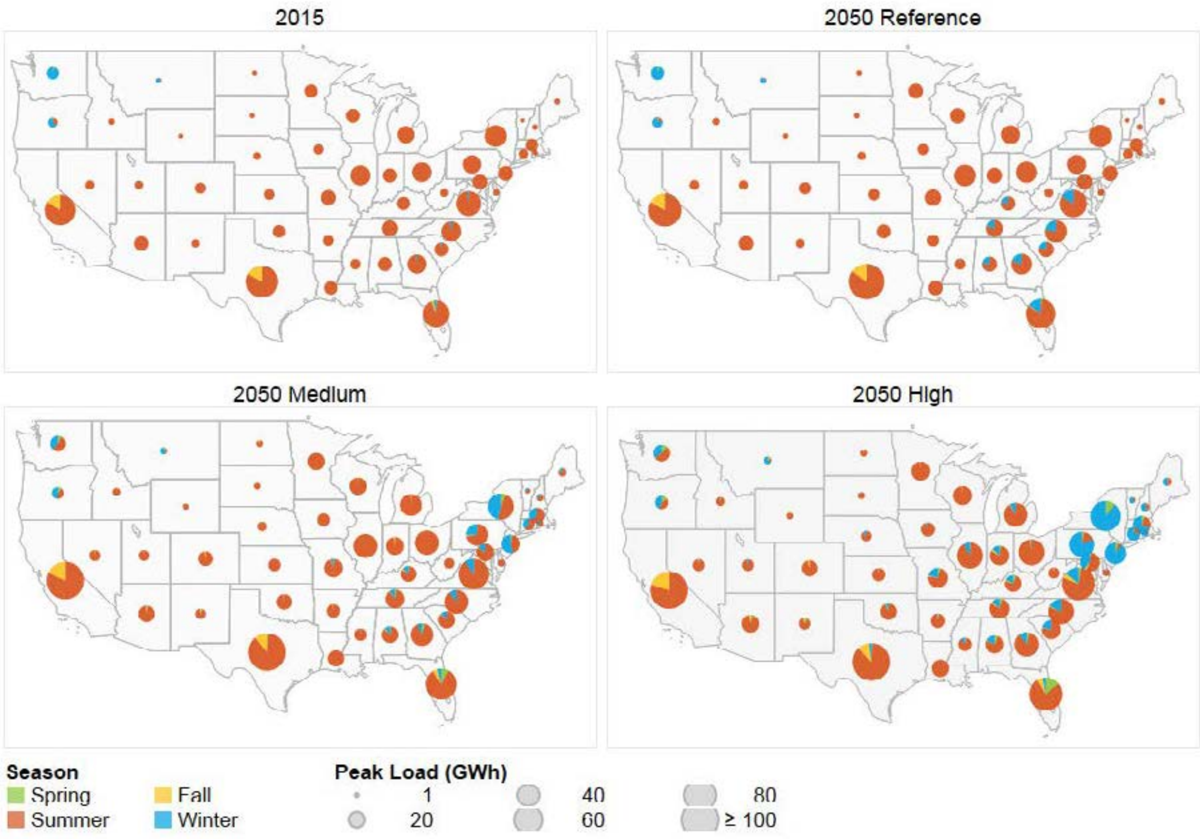
Source: EPRI (2018).

In areas with hot summers, peak electricity demand for cooling could rise significantly above the mean, especially as climate change increases temperatures and the severity of heatwaves (IEA, 2018). In addition, more than 1.1 billion people globally now have inadequate access to cooling, largely in Africa and Asia. Meeting their needs for cooling will thus require large increases in electricity supply. In Indonesia and India, for example, new space cooling demand could constitute up to 40% of the countries' entire electricity demand growth to 2050 (IEA, 2018).

In the end, most electricity systems will need to contend with some form of seasonal impact due to the electrification of heating and cooling. In some cases, the highest peaks in demand could actually move from summer to winter[12] because of widespread adoption of air source heat pumps, as one US study shows (Figure 16) (Mai et al., 2018).

12 Planners will inevitably face uncertainty in this process, as evolution of demand will also be influenced by behavioural change. See for example Halvorsen and Larsen (2013), which discusses how heat pump installation could trigger behavioural change that leads to increases in household energy consumption in Norway.

Figure 16 Peak load season by state and scenario in the United States



The size of the pie charts corresponds with total electricity demand gigawatts (GW) during the top demand hour. The pie wedges show the seasonal distribution of the top 100 hours with the highest demand by state. Seasons are defined along monthly groupings: summer includes June, July, and August; fall includes September, October, and November; winter includes December, January, and February; and spring includes March, April, and May. Moderate technology advancement projections are shown. Data shown, including 2015 data, are based on modeled estimates.

Notes: 2050 Reference = "the least incremental change in electrification through to 2050, which serves as a baseline for comparison with the other scenarios"; 2050 Medium = "a future with widespread electrification among the "low-hanging fruit" opportunities in EVs, heat pumps and selected industrial applications, but one that does not result in transformational change"; 2050 High = "a combination of technology advancements, policy support and consumer enthusiasm that enables transformational change in electrification".
Source: Mai et al. (2018).

One key solution to these problems of seasonal increases and shifts in the timing of electricity demand is thermal storage. Not only can heat be stored in summer for use in winter, but storage can also occur in winter and be used later for cooling (IRENA, 2020f) in much the same way that natural gas is now stored to meet anticipated future demand.

Principal technologies for seasonal storage include underground thermal energy storage, such as aquifers, and tank thermal energy storage, which is already used in district heating and cooling. New and emerging approaches include storage using chemicals, salts and liquid air.

Thermal storage may not be sufficient, however, to address significant seasonal heating and cooling demand peaks under scenarios of total direct electrification. Another solution, therefore, may be indirect electrification through the use of renewably produced hydrogen and other fuels, as described in the following section.

Regardless of the generation and storage solutions that are used to meet shifting seasonal demand peaks, it should be a matter of course that planners also consider the reliability of those solutions in the severe weather conditions of relevant seasons. It could be the case that new smart electrification strategies have not yet been deployed in the context of heat waves or cold snaps, so adequate technical standards and quality assurance must always be considered before deployment at scale.

Box 7. Cross-cutting strategy: Distributed energy resources to support the grid and expand electrification opportunities

Distributed energy resources consist of various resource types and technologies that may be located on low- to medium-voltage networks, including distributed generation plants such as rooftop solar PV, and other enabling technologies such as behind-the-meter batteries, EVs, residential heat pumps and demand response, among others. In most systems, these resources are operated on a "plug in and forget" approach. With further deployment, this approach can harm the system.

However, these resources can be a source of solutions, rather than potential problems, by covering all three smart electrification strategies discussed above (better matching of supply and demand, providing grid services, and expanding opportunities for electrification).

For example, while the amount of flexibility or ancillary services provided individually by different distributed resources can be small, business models that enable the aggregation of these resources can effectively make them behave like a single, large, predictable source by co-ordinating the behaviour of a large number of distributed devices, using ICT devices (the concept of virtual power plants [VPPs]). A VPP is basically a system that relies on software and a smart grid to remotely and automatically dispatch and optimise the distributed energy resources. In orchestrating distributed generation like solar PV, alongside storage systems, controllable and flexible loads, and other distributed energy resources, VPPs can provide fast-ramping ancillary services, replacing fossil fuel-based reserves. The regional transmission organisation PJM in the United States has shown that 80% of its distributed energy resource capacity comes through VPPs.

Significant reductions in the cost of distributed residential and commercial solar PV may also spur new demand for end-use technologies that take advantage of low-cost self-generated electricity. In looking at high self-consumption shares for residential PV systems, for example, Keiner et al. (2019) found that households in areas with very good solar conditions could theoretically cover up to 100% of their demand for electricity and heat in 2050 with a mix of rooftop PV, batteries, heat pumps, thermal energy storage and EVs. Even areas with lower solar potential and higher heat demand, like Canada and Northern Europe, were found in the study to cover around 60-75% of electricity demand and 60-70% of heat demand through self-production.

Lower costs of distributed renewable energy can also create new economic opportunities for mini-grid technology, which can both expand electricity access to otherwise fossil-fuelled remote areas, and even provide a form of flexibility if eventually connected to the main grid (IRENA, 2019d).

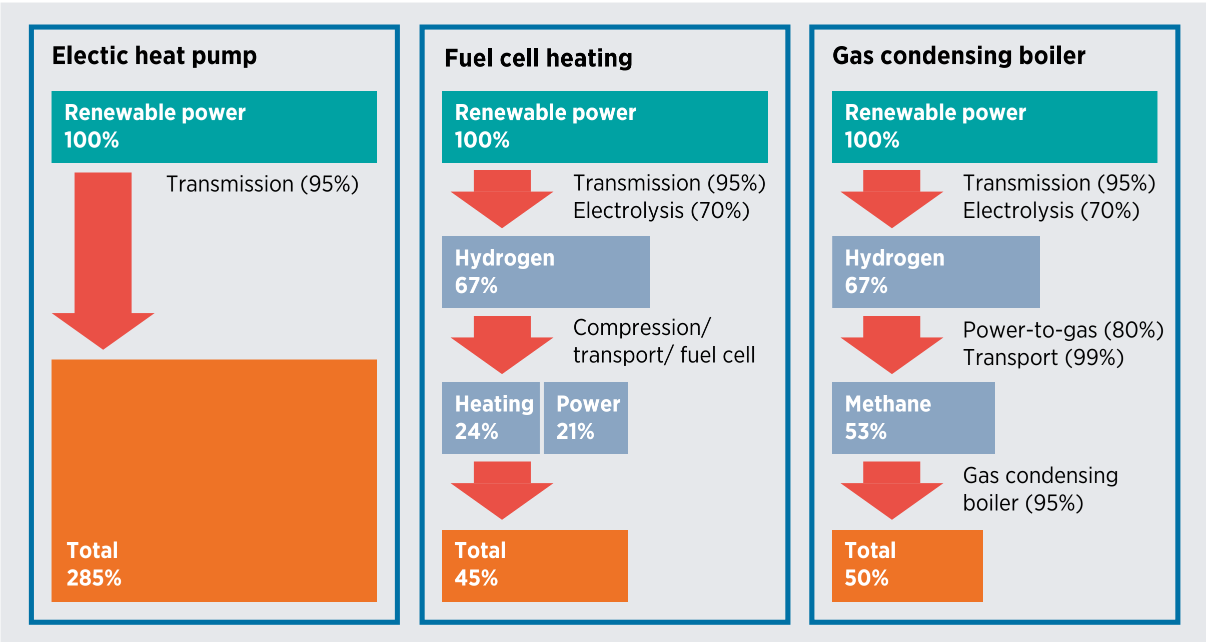
All of these potential capabilities of distributed energy resources can significantly reduce pressure on grid network infrastructure, by either alleviating flexibility or congestion issues, or even deferring and preventing the need for grid upgrades and expansion.

INDIRECT ELECTRIFICATION – SMART STRATEGIES SOLVE POTENTIAL PROBLEMS

Renewably produced hydrogen and its derivative e-fuels can make it possible to indirectly electrify –and thus, decarbonise – sectors that are hard to power directly with electricity, such as long-haul shipping and industry.

Producing these fuels, however, can put new stresses on the power system infrastructure. For example, meeting a given amount of useful demand with hydrogen or other e-fuels requires greater amounts of renewable power capacity than does direct electrification (such as with heat pumps), because of the conversion losses of making the fuels (Figure 17). In addition, electrolysers for hydrogen production typically require relatively high load factors to be economically attractive investments. As a result, there are risks that not enough renewable electricity will be available to meet the planned hydrogen demand economically, or even at all.

Figure 17 Efficiencies for different heating systems, starting from renewable electricity



Source: Perner, Umteutsch and Lövenich (2018).

Smart strategies can help solve these potential problems. The question of whether enough low-cost renewable energy is available can be addressed by siting production facilities in strategically advantageous locations. Other strategies can improve the value of hydrogen production as an alternative to direct electrification options, by providing unique additional benefits. The value that comes from being able to store hydrogen, to use T&D infrastructure or to add flexibility may offset higher costs of production. The sections below discuss these strategies in more detail, while the following Section 2.4 addresses the trade-offs and optimal balance between smart indirect electrification and direct electrification.

Hydrogen production to be strategically sited to take advantage of abundant low-cost power

The expansion of low-cost renewable sources around the world is providing unique opportunities to remake or create new energy markets. This is a particularly attractive prospect in the industrial sector, where highly energy-intensive industries may be hard to decarbonise through direct electrification, and may rely on hydrogen or e-fuels as a result. Industrial relocation of operations to areas with high-quality low-cost renewable sources could take advantage of optimal hydrogen production conditions, increasing the share of electricity used in the sector. Co-location of whole industrial clusters in such areas could build on that opportunity, leveraging digitalisation and operational synergies for increased efficiency as well (Accenture and World Economic Forum, 2021).

There is already precedent for such strategies. Aluminium smelters in Iceland have located near large hydropower resources to take advantage of low-cost electricity, and newer sources of electricity demand, such as large-scale data centres, are doing the same. Relocation is also a possible approach for the production of ammonia and other chemicals, as well as steelmaking. In steelmaking, some of the largest iron ore deposits in the world are located in Western Australia, southern Brazil, northern Chile, western China, Mauritania and South Africa, which are relatively close to areas with very good renewable energy resources (IEA, 2017). Research has shown that renewable hydrogen-based steel production can become the least-cost supply option from these markets with availability of sufficiently low-cost renewable electricity (Gielen et al., 2020).

A related strategy is using low-cost renewable generation to make hydrogen that could be shipped to regions where generation is more costly. Chile, for example, sees economic opportunity in using its uniquely low-cost renewable resources, such as solar facilities in the Atacama Desert, to make hydrogen that can be sold in countries with a net demand, such as Japan and Korea.

Box 8. Strategic siting of hydrogen production

The Swedish Energy Agency, along with companies SSAB, LKAB and Vattenfall, is supporting a pilot initiative in northern Sweden for an entirely fossil fuel-free process for steel production using hydrogen made with hydro and wind power. The goal is to make the steel industry fossil fuel-free and fully competitive with traditional steel by 2035. The initiative, called Hybrit, could reduce Sweden's total CO_2 emissions by 10%, and Finland's by 7% if expanded. Success is expected to depend on continued support from government, research institutions, universities and companies. It will also require good access to fossil-free electricity, improved infrastructure and rapid expansion of high-voltage networks, other research initiatives, faster permitting processes and long-term support at the EU level (Hybrit, 2018).

In Iceland, the company Carbon Recycling International has managed to produce 4 000 t/yr of carbon-neutral methanol from renewables-based electrolysis and CO_2 captured from a geothermal power plant (IEA, 2017). Iceland's abundant low-cost hydropower and geothermal energy has also made it an attractive location for other energy-intensive industries, like aluminium smelting. Iceland now produces about 3.4% of the world's aluminium (Pines, 2018).

Seasonal hydrogen storage to allow surplus renewable electricity to be stored for months

Renewably produced hydrogen can act as electricity storage, thus deferring or reducing the need for investment in the electricity network that might otherwise be required with VRE. The storage could be especially valuable in places with line congestion and high concentrations of VRE. Surplus power could be used to make hydrogen for storage and distribution in the existing gas infrastructure (Blanco et al., 2018).

Although surplus renewable electricity can be stored using various technologies, including batteries, the production of hydrogen has advantages since the gas can be stored in large quantities and for long periods of time, up to several months. For example, the amount of energy already stored in the form of methane in the current EU gas grid is roughly 1 200 TWh, equal to roughly one-fifth of the total European natural gas demand (IRENA, 2018b).

Long-term hydrogen or e-fuel storage can help countries with significant seasonal differences between power demand and renewable power generation to integrate more renewable power in their energy systems. In Germany, for example, winter energy demand is 30% higher than in summer, yet renewable energy sources generate around 50% less power in winter than in summer (Hydrogen Council, 2017). A switch to hydrogen, using existing gas infrastructure, can avoid the need to expand the electricity grid and help decrease the curtailment of VRE. One study shows that power-to-gas approaches can reduce the required wind and solar capacity by as much as 23% and curtailment by as much as 87% (Lyseng et al., 2018).

Given the large capacity of gas networks, even low blending shares of renewably produced gas could enable the absorption of significant quantities of VRE. Optimal blending concentrations strongly depend on the characteristics of the existing network, natural gas composition and end-use applications. Existing studies show that, generally, at relatively low hydrogen concentrations (up to 10-20% by volume), blending in current infrastructure may not require major investment or modification to the infrastructure and can be done in a safe manner (IRENA, 2018b).

Box 9. Case studies – Seasonal hydrogen storage

A study by Lawrence Berkeley National Laboratory estimated that between 2017 and 2025, between 3 300 GWh and 7 800 GWh of solar and wind energy may be curtailed in California unless additional demand can be found. Hydrogen gas made from that excess electricity could be used to power fuel cell cars and trucks, or it could be blended with natural gas and used in anything that is gas-fired. If all of the excess solar and wind energy that the study predicts in California were converted to methane and stored as renewable natural gas, it would provide enough energy to heat up to 370 000 homes or provide enough electricity for up to 187 000 homes (IRENA, 2019b).

A consortium led by ENGIE has created the GRHYD hydrogen energy storage project in France. France has aimed to meet 23% of its gross end-user energy consumption with renewable sources, so the GRHYD project aims to convert the surplus energy generated from renewable energy sources to hydrogen. The hydrogen produced is blended with natural gas into a product called Hythane, which is then incorporated into the existing natural gas infrastructure. The project aims to demonstrate the technical, economic, environmental and social advantages of mixing hydrogen with natural gas as a sustainable energy solution (IRENA, 2019b).

Hydrogen electrolysers to offer important grid services

The electrolyser systems used to produce hydrogen can be cycled up and down rapidly as a flexible load, providing grid services such as frequency regulation. Proton exchange membrane (PEM) electrolysers are better suited for such operation than today's dominant alkaline electrolysers. However, PEM electrolyser costs need to at least halve, while efficiencies need to increase further to the level of alkaline electrolysers (IRENA, 2018b).

Box 10. Case studies – Electrolyser grid services

Hydrogenics Corporation completed a trial in 2011 with Ontario's independent electricity system operator aimed at demonstrating the use of electrolyser technology for utility-scale grid stabilisation services. Experimental analysis done by the US National Renewable Energy Laboratory also shows that electrolysers can rapidly change their load point in response to grid needs and at the same time accelerate recovery in case of frequency deviation (Gardiner, 2014).

In Austria, the H2Future project is piloting a 6 MW electrolyser at the Voestalpine Linz steel production site. It is expected to study the use of the electrolyser to provide grid balancing services such as primary, secondary and tertiary reserves, while also providing hydrogen to the steel plant. The hydrogen would be produced using electricity generated during off-peak hours to take advantage of time-of-use power prices (IRENA, 2019j).

2.4 SYSTEMIC TRADE-OFFS AND ECONOMIC ASSESSMENTS – WHERE AND WHEN DO DIFFERENT ELECTRIFICATION PATHWAYS MAKE THE MOST SENSE?

While previous sections discuss individual electrification technology options, cost drivers and smart strategies, this section aims to evaluate them in a wider systemic context. This perspective is required to better understand economic trade-offs between different electrification pathways, and to identify the lowest-cost solutions for systems as a whole.

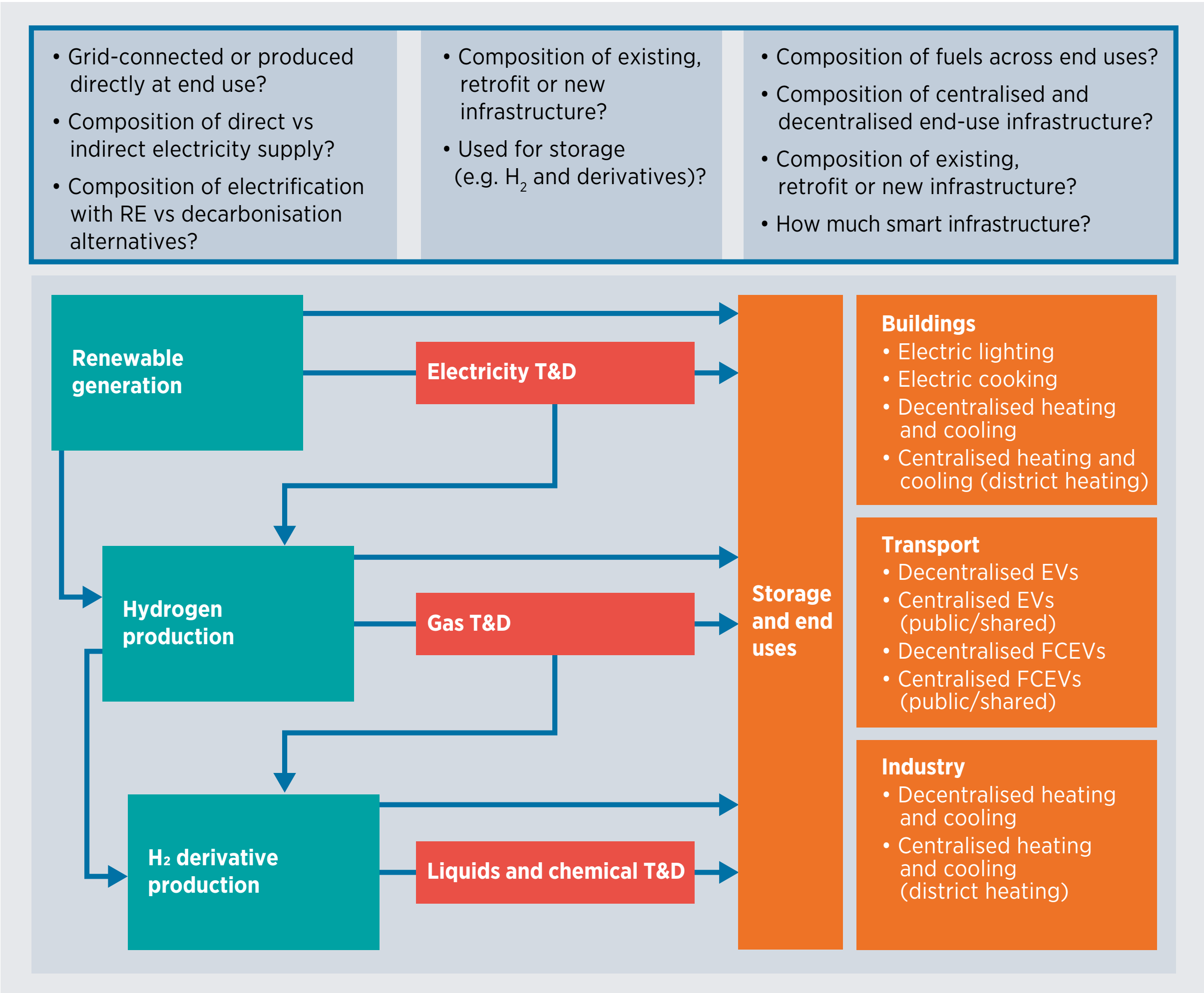
As discussed in this report's introduction, a key enabler of a deeply decarbonised world is the increasing availability of cheap renewables-based power generation. Indeed, solar and wind electricity generation is already cheaper than fossil-based electricity in LCOE terms in many places around the world.

However, there are many options for how to use that renewable electricity. Each option will have different costs depending on the specific end uses and the infrastructure needed to deliver the electricity to those end uses. For example, direct electrification of an industrial process may be theoretically cheaper than using renewables-based hydrogen, but retrofitting existing plants to use electricity directly may be prohibitively expensive, tipping the balance to the hydrogen-based solution.

Looking at the even larger picture, marginal increases in electrification at some point may require new infrastructure investments that are so large that other decarbonisation solutions, such as bioenergy or carbon capture, may be less expensive than electrification if they are available.

Figure 18 shows some of the many trade-offs that must be considered in any attempt to optimise electrification and decarbonisation pathways. There are key questions to be addressed at each stage of production, transmission and distribution, storage and end use. In addition, decisions in one area will spill over to affect other areas. For example, shifting to a smart, centralised district heating system based on hydrogen may lower costs in the electricity distribution network and for building retrofits, but it may also increase the cost of renewable electricity capacity needed for hydrogen production. Moving from one energy state to another also incurs additional costs and conversion losses, which must be taken into account.

Figure 18 Overall infrastructure landscape for smart electrification pathways



It is difficult to assess and model all of these economic complexities together. However, a number of studies have focused on key parts of the overall landscape, for example on how much electrification is sensible in certain sectors, or on the prospects for a particular fuel like hydrogen across sectors.

This section presents the most important findings from those studies (which are also listed and summarised in Appendix V). **Taken together, the studies to date do present certain areas of consensus around three key principles: efficiency first, maximising the use of renewable generation in "infrastructure-efficient" direct-electrification pathways, and making intelligent use of indirect electrification's advantages in energy-dense end uses and long-term system-wide flexibility.**

SECTORAL ASSESSMENTS

Transport

A number of studies have attempted to model the trade-offs among different transport sector electrification pathways, with the goal of understanding how much, and what type of, electrification with renewables is economically feasible. It is important to note that these studies did not explicitly assess trade-offs with the electrification of other sectors, however.

In a study of electrification of transport in Germany, Öko-Institut (2014) found that a passenger car fleet comprising 75% EVs by 2050 could add up to 100 TWh of demand (or around 17% of current total electricity demand). An additional 50 TWh would be used for electric trucks and electric road systems in road freight (for a total of 25% of current total electricity demand). This would require a concurrent investment in additional renewable generation capacity. But follow-up studies show that this direct electrification pathway is more cost-effective than transport options based on hydrogen or its derivative e-fuels. The reason is that the production of hydrogen or renewable e-fuels would require roughly two times or five times more electricity, respectively, than powering the vehicles directly with electricity (Zimmer et al., 2016), and the cost of the additional electricity generation is much greater than the savings from using existing vehicle designs and fuel infrastructure. As a result, the studies recommend e-fuels should be used only when direct electrification is less feasible, such as in aviation. There is also a strong recommendation to free up as much electricity as possible by actively reducing overall transport demand through efficiency and public transport.

Similarly, Colbertaldo, Guandalini and Campanari (2018) showed that in Italy it would be difficult to produce enough renewable hydrogen to power a national fleet of vehicles. They found that in a scenario with only 30% FCEVs in road transport by 2050, the “technical maximum” share of renewable generation they explore, at 57% of total generation, would only meet 81% of hydrogen mobility demand. Given these limitations, the study recommends strong measures to reduce vehicle travel or electrification through other technologies.

Several studies have expanded such analyses beyond the country level. Looking at electrification of the passenger car stock in the European Union, Kasten et al. (2016) found that a vehicle fleet comprising 80% EVs in 2050 would require an additional 170 GW of renewable generation capacity. That amount is 75% of the EU renewable generation capacity in 2010, and a 22% increase in expected renewable energy capacity by 2050.

While those amounts of additional renewable generation capacity appear large, the key message from this study and many others is that the most feasible and cost-effective route to decarbonising transport is directly electrifying as much of the sector as possible (along with steps to boost efficiency and reduce overall demand). Not only are technologies like EVs increasingly competitive, but the amount of electricity generation capacity that would need to be built if FCEVs and e-fuels were widely used would be prohibitively costly.

For example, Siegemund et al. (2017) found that that even if 80% of EU passenger vehicles were EVs in 2050 (and 20% FCEVs), 70% of the final energy demand in transport would be for the production of hydrogen and its derivative e-fuels, mainly for use in freight transport, aviation and shipping.

More specifically, the economic assessments do not find any scenarios where the pathways to direct electrification (including investment in charging stations and power distribution upgrades) cost more than the additional generation capacity that would be needed for indirect electrification. This reflects the need to focus indirect electrification solutions more narrowly on transport sub-sectors with few to no decarbonisation alternatives. This conclusion grows even stronger when competition for the use of renewable hydrogen and its derivative fuels in other sectors is considered.

Heating and cooling in buildings and industry

While fewer dedicated studies exist on the trade-offs between large-scale direct and indirect electrification in the buildings and industrial sectors than in transport, a number of analyses show a similar result: that the different requirements in generation capacity for direct vs indirect electrification often play the critical role in overall cost-effectiveness. As direct electrification solutions are not yet readily available for certain high-grade heat requirements, the studies also emphasise the crucial importance of reducing overall demand through efficiency and other measures. In addition, they show that district heat in urban areas is usually more cost-effective than decentralised urban heating, and they suggest that alternatives to indirect electrification with e-fuels, such as biofuels, can play important roles.

In the buildings sector, for example, a study of nearly full decarbonisation of the United Kingdom's residential heating by 2050 found that an approach based mainly on heat pumps (61% met by decentralised heat pumps, and 17% centralised through district heating heat pumps) could add 48 GW to winter peak demand for electricity, and require GBP 16-28 billion of distribution network upgrades (depending on the rollout of smart solutions) (Delta Energy & Environment and Energy Networks Association, 2012). Keeping the district heat share similar (at 27% rather than 34% of demand), but meeting 25% of demand through biomethane in about one-fifth of the existing gas network capacity (about 75 TWh), could cut the additional winter peak demand in half, to 24 GW. It would also reduce the cost of the required distribution network upgrades to GBP 8-14 billion. While the study did not look at hydrogen-based options, those options also could theoretically reduce peak generation and distribution system impacts, depending on the costs of the off-peak renewable energy capacity needed to produce 75 TWh of hydrogen.

In industry, the use of renewable hydrogen to meet high-grade heat and feedstock demand poses similar concerns about the additional power capacity that would be required for indirect electrification. One theoretical study found that complete electrification of the energy-intensive basic materials industry in Europe (steel, cement, glass, lime, petrochemicals, chlorine and ammonia) would add up to an annual electricity demand of about 1 700 TWh (about 1 100 TWh of which would be for e-fuels). That is larger than the entire current industrial energy demand in Europe (1 000 TWh) (Lechtenböhmer et al., 2016). The study also showed that the need for this added generation infrastructure could be reduced through strong efficiency measures and some use of bio-based materials/fuels, especially if they can displace e-fuels. In another study, Bazzanella and Ausfelder (2017) similarly showed that indirectly electrifying Europe's chemical sector using e-fuels would require 40% more carbon-free electricity generation than that projected to be available across the whole of the European Union by that time (under the IEA's 2°C scenario).

Most of the scenarios above highlight the need for strong reductions in demand and expansion of district heating networks (particularly for buildings). Indeed, while the renewable energy capacity differences in direct vs indirect approaches are important economically for all sectors, network infrastructure appears to play a larger role in the results from heating and cooling sector studies. For example, a study of 100% renewable energy systems for the EU28 countries by 2050 found that overall costs are lower with a combination of decentralised heat pumps and district heating for residential heat than with decentralised heat pumps alone. The reason is that costs for thermal pipe networks in district heating are substantially lower than the costs of individual heat pump installation and individual building retrofits (Connolly, Lund and Mathiesen, 2016).[13]

Overall, given the significant amount of renewable capacity needed for the production of hydrogen and e-fuels, and their likely need in these sectors (particularly in hard-to-replace feedstocks in industry), the sensible extent of electrification in studies of heating and cooling appears to be driven by first limiting electrification to the extent possible – through demand reduction, efficiencies via smart strategies and centralised district heating, or decarbonisation alternatives that make use of existing infrastructure (e.g. bioenergy).[14] These approaches have the added benefit of also reducing the cost of new T&D, storage and end-use technology investment needs. Once electricity demand is reduced to the extent possible, choices of when to use direct or indirect electrification strategies can be made with an overall focus on minimising generation capacity needs.

Box 11. **Heat Roadmap Europe – An extensive analysis of infrastructure for heating and cooling electrification**

Perhaps one of the most extensive analyses of electrification in these sectors so far, the Heat Roadmap Europe, confirms the broad conclusions from many other studies, and gives a sense of how far specific types of heating and cooling electrification are economically sensible given broader infrastructure impacts and trade-offs discussed for these particular sectors (Paardekooper et al., 2018). The study, which explores Paris-compliant decarbonisation scenarios for 14 European countries, finds roughly four complementary strategies which can be optimally deployed at different levels – thermal energy savings and process efficiency, district heating and cooling, efficiencies in thermal and electrical grid coupling, and individual heat pump rollout.

As in studies mentioned previously, demand reduction is a fundamental element in the transition, and the study finds the greatest potential to be in reducing space heating and process heating demand vs a reference case scenario to 2050 (by 5% and 14%, respectively).

A key finding of the study is the cost-effectiveness of district heating in the vast majority of urban contexts, with results showing it optimally supplies roughly 50% of heating demand in all countries analysed (up to 70% in certain contexts), due to the greater diversity of electric and low-carbon supply options available to district systems versus individual systems, lower cost of thermal grid expansion versus individual heat pump and electricity distribution grid installation, and lower cost flexibility and storage options available to district systems.

13 A near, but imperfect, analogue to the cost advantages of centralised district heating systems in the transport sector would be increasing the share of public transport in order to reduce charging network infrastructure costs. While this is almost always a suggestion in transport sector studies, the quantification of network infrastructure savings is not present to the extent that district heating is quantified in economic assessments of heating and cooling sector electrification.

14 These general principles derived from sectoral economic assessments discussed here have also been supported by other reviews of smart heat sector electrification principles; see for example Rosenow and Lowes (2020).

While district heating is straightforward as a centralised option for direct electrification, with about 20-30% of its supply coming from large-scale heat pumps to take advantage of VRE in the analysis, it also makes use of efficiencies in a coupled and smart thermal-electric grid. As in studies discussed earlier in this section, retaining a certain share of existing infrastructure is a sensible complement to electrification in many contexts. In this analysis, 25-35% of district heat supply comes from CHP powered by biomass or minimal natural gas, which remains connected in 2050. But about 25% of district heat supply also comes from industrial waste heat from sectors such as chemical or steel manufacturing. These sources can make use of existing thermal infrastructure where available, and crucially, excess heat from e-fuels production needed in those sectors can also act as a source of district heat supply. This possible synergy reflects the additional value of strategically siting hydrogen production, as discussed in earlier sections. The ability to attach larger-scale thermal storage units to district heating systems also offers lower costs than individual storage alternatives.[15] The remainder of district heat supply in the analysis also reflects a unique ability to take advantage of other renewable heat options such as solar thermal and geothermal (together about 5% of supply), freeing up renewable power capacity for more electricity-intense e-fuel production.

While the study notes that solutions with less or no district heating certainly exist, e.g. through increasing shares of individual heat pumps or biomass boilers in buildings and industry, the loss of systemic efficiencies and cost advantages outlined above makes fully electrified supplies less desirable.

In the remaining 50% of heat supply to rural areas, however, direct electrification through individual heat pumps is seen as the most cost-effective, for two broad reasons. First, although the costs of heat pump and electricity grid expansion are not insignificant, for geographical reasons they are found to be lower than the costs of much further district heating network expansion and the resulting distribution losses. Second, the strategy also saves renewable energy capacity relative to indirect electrification of those areas, due to the reduction in primary energy demand from heat pumps, and their ability to make use of otherwise-curtailed VRE generation through smart, flexible operation.

15 *The value of larger-scale centralised solutions to a certain extent for flexibility reasons is reflected in other targeted studies, e.g. Quiggin and Buswell (2016). They assessed six UK scenarios to 2050 with electrified heat, using detailed hourly data to see if the electricity demand is met at all hours of the year, with all but two scenarios assuming heat pumps meet more than 75% of heat demand. The assessment showed that all but one scenario demonstrated serious supply issues on winter days when heating demand is high, even if flexibility options such as demand-side management, battery storage and V2G, among others, are fully utilised. The scenario that contained a significant portion of CHP generation was the only one without problems.*

SYSTEM-WIDE ASSESSMENTS

The sector-specific studies discussed thus far provide a number of clear insights into the sensible extent of smart electrification pathways, given their respective system impacts. Across the board, even before electrification occurs, strong demand reductions are proposed in nearly all studies regardless of sector, in order to reduce the need for unnecessary electricity generation infrastructure. Certain studies then suggest sustainable bioenergy and other decarbonisation alternatives can be applied where necessary in hard-to-decarbonise sub-sectors, such as aviation and shipping, or chemicals and heavy industry. District heating systems are seen to play a particularly important role in wisely utilising less electricity for heating and cooling, particularly given the typically lower cost of their overall infrastructure options/needs (across generation, T&D, storage and end-use technology) as compared against decentralised heat pumps in urban environments. Such thermal networks can also offer larger-scale and more diverse storage solutions for seasonal heating and cooling issues than a fully electrified system, ideally resulting in less overall need for infrastructure capacity.

Once efficiencies and alternatives have been exhausted, however, each set of sectoral economic assessments also lays out varying optimal shares of remaining direct and indirect electrification. As seen, these shares also largely follow the principle of minimising electricity capacity needs, which (at least at the system-wide level) appears to be the more dominant economic impact of infrastructure for the competing pathways.[16] What could be thought of as light uses – e.g. light-duty vehicle demand, rural heating and cooling demands – are candidates for direct electrification to the fullest extent possible given the availability of increasingly competitive end-use technologies (EVs and heat pumps) and access to smart electrification strategies, which reduce their network infrastructure costs. What could be thought of as heavy uses, which require energy-dense fuels – e.g. aviation, long-distance shipping and high-temperature heating – are candidates for majority indirect electrification through hydrogen and its derivative e-fuels if no decarbonisation alternatives are available. The additional electricity generation required for them is seen as necessary due to lack of competitive direct electrification end-use technologies.

While these insights feel intuitive at the sectoral level, it is important to confirm the extent to which they hold true in economic assessments that consider all three sectors that are competing for renewable electricity resources. For example, perhaps hydrogen networks offer synergies across three sectors that surpass their benefits in one sector only, meaning they should in fact be sized larger despite the need for more generation capacity. Or, perhaps the electricity network impact of heat pumps and transport combined raise electricity network costs to the extent that there would be a case for retaining more than the 20-30% of gas networks seen in some previously discussed studies.

Such comprehensive economic assessments of the full infrastructure landscape are also unfortunately scarce, although several exist that could provide insights. A simple way to gauge the results of such studies against the benchmark principles described above is to explore the extent to which indirect electrification pathways make up larger or smaller shares of demand in the comprehensive analyses, versus the sectoral analyses already discussed. A review of 22 existing electrification scenarios by Ruhnau et al. (2019) is a useful overview of this in the German context. Table 5 provides an idea of the current gaps in the literature, even in a country context where such electrification assessments are more advanced. For example, only two studies cover electrification in all sectors, in a 100% decarbonised context.

16 At more isolated levels, such as a local network, other limiting/guiding principles may be present which may preclude electrification or force the determination of electrification options – as discussed in Chapter 4, systemic planning should always be aligned with regional or local planning whenever possible.

Table 5 Overview of electrification scenarios in the German context

No.	Reference	Heat Electrification		Transport Electrification		ΔGHG		
		Buildings	Industry	Cars	Trucks	Trend	≥80%	≥85%
1	DLR et al. [18]			✓	✓		80%	
							80%	
2	Oeko-Institut [19]			✓	✓		84%	90%
3	Prognos et al. [20]	✓	✓	✓	✓	65%	80%	
4	UBA [21]	✓	*implicit*	✓	✓			100%
5	DLR et al. [22]			✓	✓		80%	
							80%	
							80%	
6	Heilek [23]	✓					80%	
7	Oeko-Institut and Fraunhofer ISI [24]	✓	*implicit*	✓	✓	54%	80%	95%
8	Robinius [25]			✓			80%	
9	Nitsch [26] [a]	✓	✓	✓	✓	58%		*95%*
10	Palzer [28]	✓	*implicit*	✓	✓		80%	86%
11	Quaschning [29] [b]	✓	✓	✓	✓			100%
12	Fraunhofer IWES/IBP [30] [c]	✓	✓	✓	✓		83%	95%
Total						**3**	**12**	**7**

[a] The study presents three scenarios in total, but the two 95% scenarios are very similar for the year 2050. Thus, we evaluate only one of the 95% scenarios (KLIMA 2050). Note that this study is an updated version of the well-known study from DLR et al. [27].

[b] This study assumes that the German emission target has already to be reached by 2040. Thus, a scenario for the German energy system in 2040 is presented, but it is very comparable to other studies' 2050 scenarios.

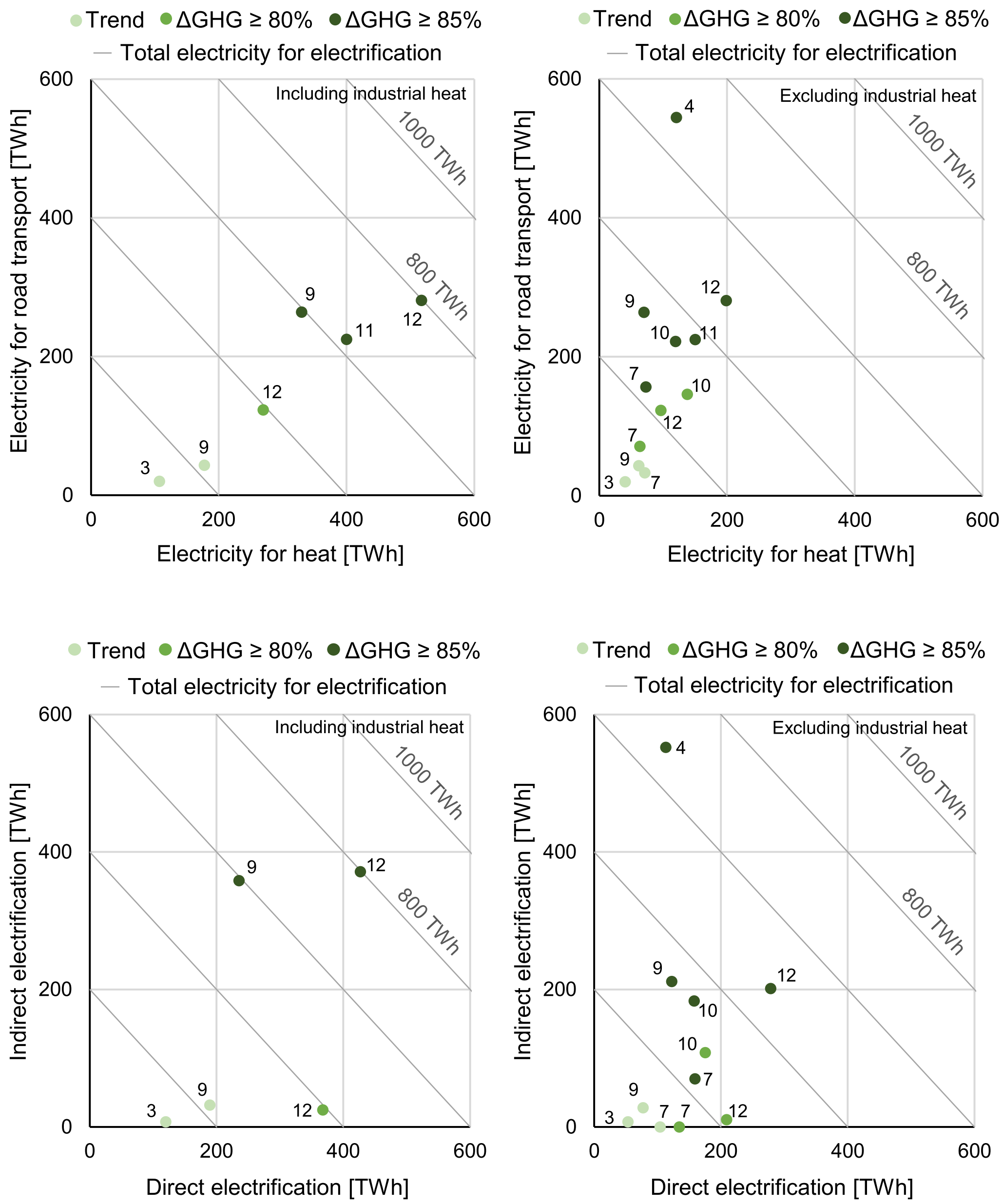
[c] Numerical details are retrieved from data appendix. Note that this study is an updated and extended version of the study from Fraunhofer IWES et al. (2015), which provides further transport scenarios at 80% GHG reduction that we evaluate in subsection 4.3.

Source: Ruhnau et al. (2019).

As Figure 19 shows below, not only are electrification rates strongly driven by the level of decarbonisation, but different sectors also have different sensitivities in this regard. More electrification is expected with greater decarbonisation of transport and industrial heating, for example, as they have fewer readily available alternatives than buildings (which have district heating and efficiency solutions), as discussed previously. Significant indirect electrification infrastructure is also only seen in highly decarbonised scenarios (> 85%), which the study contends is a result of their more economic application in hard-to-decarbonise sectors in transport and industrial heating, as well as their role in long-term storage networks for higher shares of VRE once the last 15% of decarbonisation is needed. As for interaction between the three sectors, studies in which industrial heat is included in highly decarbonised scenarios do not appear to reduce the electricity used for transport/buildings or displace direct electrification in transport/buildings, implying that indirect electrification of hard-to-decarbonise industry occurs later in time and is additive. The meta-analysis thus seems to reinforce the general principles discussed above: the need to reduce energy demand and the advantages of direct electrification.

Photo: Malevic / Shutterstock.com

Figure 19 Levels of electrification in a sensitivity analysis of future German transport and heat sector scenarios



Source: Ruhnau et al. (2019).

In an even wider assessment of the comprehensive infrastructure landscape for electrification in the whole of the European Union by 2050, the EU ASSET project adds important nuances to the extent and role of indirect electrification in a system-wide context (De Vita et al., 2018). Although the assessment finds similar shares of optimal hydrogen and e-fuels as other studies, mainly to meet demand in hard-to-decarbonise sub-sectors (resulting in a total share of only 12-30% in transport, and 12-15% in industry), it stresses that these shares are in fact economically preferable to minimising indirect electrification even further. Two broad reasons are provided for this, from an overall system perspective. First, although hydrogen and e-fuel production does imply significant need for generation and network infrastructure, the ability of a single hydrogen network to meet all three sectors' hard-to-decarbonise demands at once allows for efficiencies compared against dedicated direct electrification infrastructure for each. Second, the dual ability of the limited hydrogen network to also act as storage and distribution greatly improves the utilisation of lowest-variable-cost renewable electricity on the continent over the year, reducing electricity peaks and actually reducing power prices overall against a direct electrification-only baseline. Having a fully sector-wide assessment of infrastructure needs is essential for the net benefits of such indirect electrification shares to become evident.

The study also stresses that the timing of such infrastructure development is important to the economic case. As other studies discussed earlier also found, indirect electrification through hydrogen and e-fuels is a more economically competitive strategy for the later stage of electrification and decarbonisation than it is for the immediate stage of direct electrification. This full-system perspective, rather than sectoral view, therefore provides a more complete rationale for the role and extent of indirect electrification in particular sectors in an economically sensible deployment of smart electrification strategies.

These economic assessment studies, taken together, show how it is possible to reduce the overall costs of decarbonisation by a careful balancing of direct and indirect electrification, with the balance changing depending on the sector and time period, combined with strong efforts to reduce energy demand in all sectors.

The following chapters of this report go into more detail about the electrification pathways discussed above in IRENA and State Grid analyses, and the priorities to consider while implementing those pathways.

3 PROSPECTS FOR ELECTRIFICATION WITH RENEWABLES IN IRENA AND CHINA STATE GRID ANALYSES

KEY MESSAGES

- IRENA analysis in its 2021 edition of the World Energy Transitions Outlook shows that in the report's main energy transition scenario, the 1.5°C Scenario, direct electricity consumption could more than double by 2050, rising to over 50% of global final energy consumption, and becoming by far the largest energy carrier.
- To keep the expected global temperature rise to 1.5°C in IRENA's 1.5°C Scenario, at least 90% of electricity generation would need to come from renewable sources by 2050, up from 25% in 2018.
- By 2050 VRE, mainly wind and solar PV, would account for 63% of total global electricity generation, rising from their current shares of 7% and 3%, to 34% and 29% respectively.
- By 2050 clean hydrogen has the potential to supply nearly 74 EJ of global energy demand, two-thirds of which would come from renewable sources and the remaining from blue hydrogen coupled with CCS. As discussed in Chapter 2, the renewables-based hydrogen can also aid the integration of VRE generation sources through solutions like smart electrolyser operation and industrial relocation.
- The increased electrification of transport and heat, as well as increased renewable energy in power generation, can deliver at least 36% of global energy sector CO_2 reduction needs by 2050, according to IRENA's analysis.
- In transport, electricity consumption in the sector would need to increase from just 1% today to 49% by 2050, with close to 1.8 billion passenger EVs – near today's current amount of total passenger vehicles – on the road.
- In the IRENA analysis, ambitious decarbonisation sees the share of electricity consumed in buildings and industry double by 2050 compared to current levels, reaching shares over 35% and 73% by 2050.
- Electricity demand in the buildings sector is projected to double by 2050. Under IRENA's 1.5°C Scenario, the number of heat pump units in operation would increase from around 20 million in 2016 to around 290 million units in 2050.
- In industry, direct use of electricity would meet more than 35% of energy needs by 2050. And 80 million heat pumps would also be installed to meet low-temperature heat needs, more than 400 times the number in use today in the sector.

- Among other global scenarios claiming compatibility with the Paris Agreement, electricity's share of final energy consumption in 2050 varies (from 42% to 52%) due to different assumptions on the amount or intensity of energy demand across sectors, coupled with different combinations of smart electrification and emissions reduction strategies in those sectors.
- There is a similarly wide range of estimates for the potential electrification of select highly developed markets, but they are somewhat higher than the world average, e.g. 41-51% share of total final energy consumption in studies looking at the United States, and 49-60% in the European Union.
- Based on modelling by the State Grid Energy Research Institute (SGERI), electrification in China is expected to have a major impact by accelerating the pace of overall energy demand reduction beyond 2030, due to efficiency gains.
- In a SGERI scenario exploring greater electrification in China by 2050, 52% of energy demand could be met by electricity, with electricity's share of energy use in buildings at 65%, transport at 35% and industry at 52%.
- That level of electrification in China would entail significant amounts of mainly VRE capacity to be built by 2050, with 1.66 TW of solar PV and 1.33 TW of onshore wind becoming the two largest sources of electricity generation capacity.

3.1 ELECTRIFICATION IN IRENA'S WORLD ENERGY TRANSITIONS OUTLOOK

IRENA has explored various possible paths for energy investment and broader socio-economic development, capturing an increasingly comprehensive picture of the impact of the energy transition on economies and societies over the crucial three-decade time frame remaining until the middle of the century.

Box 12. **IRENA decarbonisation pathways for the global energy system to 2050**

IRENA's latest report, the *World Energy Transitions Outlook*, presents four scenarios representing possible paths for the global energy transformation:

- **The Planned Energy Scenario (PES)** is IRENA's primary reference case, providing a perspective on energy system developments based on governments' current energy plans and other planned targets and policies (as of 2019), including nationally determined contributions under the Paris Agreement unless the country has more recent climate and energy targets or plans.
- **The Transforming Energy Scenario (TES)** describes an ambitious, yet realistic, energy transformation pathway based largely on renewable energy sources and steadily improved energy efficiency (though not limited exclusively to these technologies). This would set the energy system on the path needed to keep the rise in global temperatures to well below 2°C and towards 1.5°C during this century.
- **The 1.5°C Scenario (1.5°C Scenario)** describes an energy transition pathway aligned with the 1.5°C climate ambition – that is, to limit global average temperature increase by the end of the present century to 1.5°C, relative to pre-industrial levels. It prioritises readily available technology solutions, which can be scaled up at the necessary pace for the 1.5°C goal.
- **The Baseline Energy Scenario (BES)** reflects policies that were in place around the time of the Paris Agreement in 2015, adding a recent historical view on energy developments where needed.

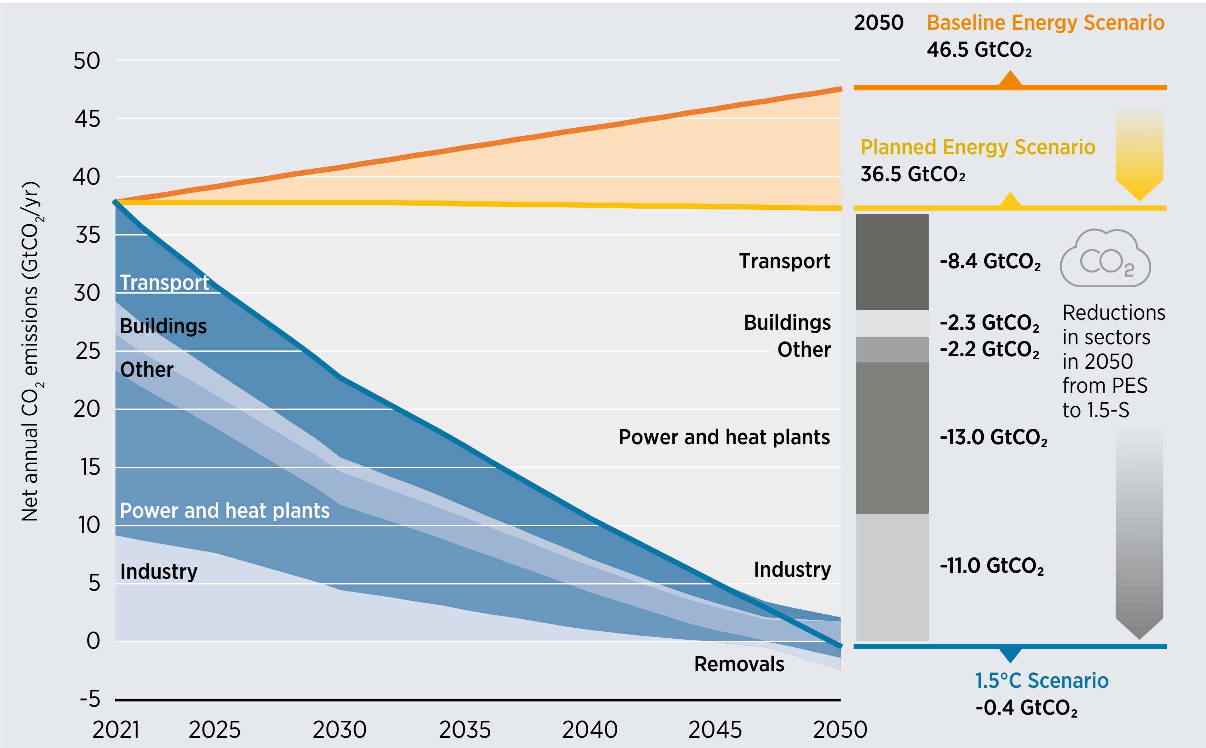
Appendix VI presents a comparison of IRENA's main energy transition scenarios to other prominent global and regional scenarios that have recently been published.

Decarbonising the energy sector and reducing carbon emissions are the key objectives of the energy transformation roadmaps of IRENA, which examine and provide ambitious, yet technically and economically feasible, pathways for the deployment of low-carbon technology towards a more sustainable clean energy future. Climate change and local air pollution are among the key drivers for energy transition worldwide. Renewables and other low-carbon technology options reduce carbon emissions, deliver socio-economic benefits, improve energy security, create jobs and help expand access to modern energy. Each of these benefits is brought closer by the steadily falling costs of renewables.

IRENA's *World Energy Transitions Outlook* presents several possible scenarios for the evolution of energy-related CO_2 emissions. In the BES, CO_2 emissions increase to 46.5 Gt by 2050 (up from 37 Gt in 2019), resulting in a likely temperature rise of 3°C or more in the second half of this century. If the plans and pledges of countries are met as reflected in the PES – IRENA's main reference case – then CO_2 emissions are expected to increase each year until 2030, before dipping slightly by 2050 to roughly just below today's level, resulting in a likely global temperature rise of around 2.5°C above pre-industrial levels in the second half of this century. Aligned with the IPCC's special report on limiting global warming to no more than 1.5°C by 2050, IRENA's 1.5°C Scenario starts with the goal of reducing global CO_2 emissions by following a steep and accelerated downward trajectory from now to 2030 and a continuous downward trajectory thereafter, reaching net zero by 2050. Additional efforts in sectors such as power, heat and industry would be needed, with negative emissions delivering the necessary additional carbon reductions.

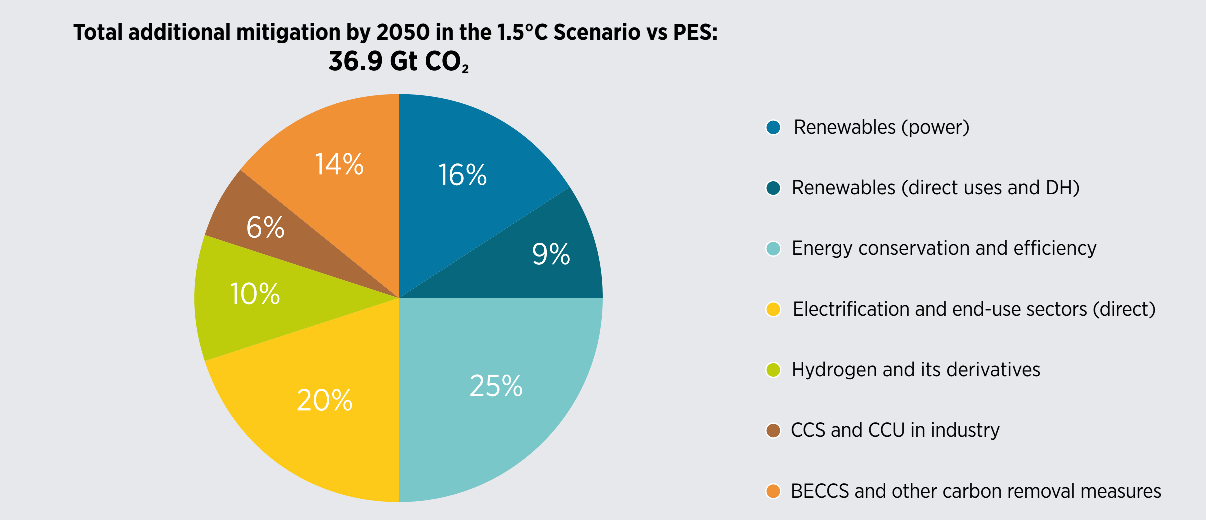
To achieve such levels of emissions reductions, an acceleration is needed across various sectors and technologies, ranging from rapid deployment of renewable power generation capacities, such as wind and solar PV, to deeper electrification of the end uses of transport (e.g. EVs) and heat (e.g. heat pumps) powered by renewables. There would be major increases in green hydrogen use, direct renewable use (e.g. solar thermal and biomass), energy efficiency (e.g. thermal insulation of buildings and process improvement) and infrastructure investment (e.g. in power grids and flexibility measures such as storage).

Figure 20 Annual energy-related CO_2 emissions in the BES, the PES and the 1.5°C Scenario, and mitigation contributions by technology in the three scenarios, 2010-2050



As described in Sections 1.3 and 1.4, electrification with renewables unlocks important synergies between major increases in the use of electricity and renewable power generation by co-ordinating their deployment and use across the demand sectors: transport, industry and buildings. As seen in Figure 21, the combined effect of increased electrification and renewable power generation reduces 2050 emissions by about 36% in the 1.5°C Scenario, compared to the PES.

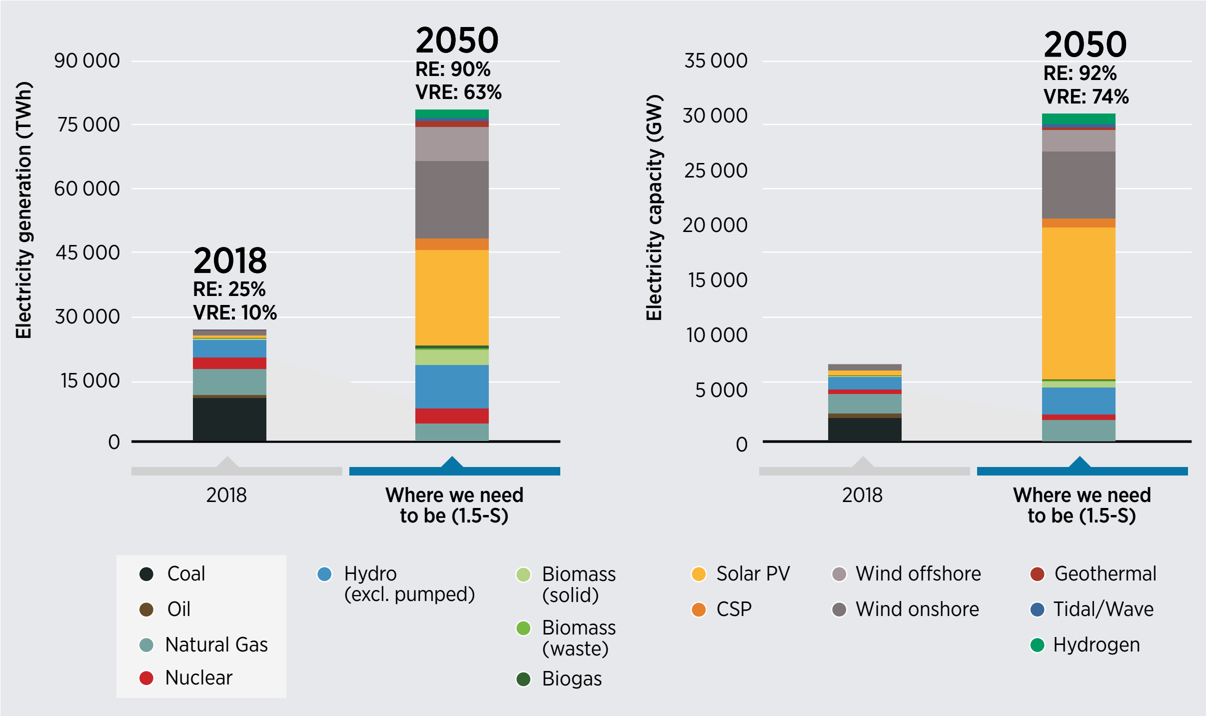
Figure 21 Further CO_2 mitigation in the 1.5°C Scenario with smart electrification vs other mitigation measures (energy-related Gt CO_2/yr)



Notes: BECCS = bioenergy with carbon capture and storage; DH = district heating; CCU = carbon capture and utilisation.

Because using electricity instead of fossil fuels is more efficient for most end uses, overall energy demand in scenarios with high levels of electrification like the 1.5°C Scenario rises less than in the PES by 2050. However, there are large differences between the sectors in the amounts of additional electric power that are needed. In the transport sector, electricity demand increases over threefold versus the PES. In industry, the relative demand drops by 24% compared to the PES. And in buildings, the net effect is a slight increase in power demand of about 10% despite a substantial increase in electricity's provision of energy services (largely the benefit of greater efficiencies from the increased penetration of heat pumps for heating applications). In addition, in the 1.5°C Scenario, 90% of electricity generation would come from renewable sources, with 63% from variable renewables (solar PV and wind), driving down the emissions intensity of power generation and enabling the power sector to be a key enabler of energy-related emission reductions.

Figure 22 Electricity generation mix (TWh) and power generation installed capacity (GW) by fuel, 2018 actual and 2050 1.5°C Scenario

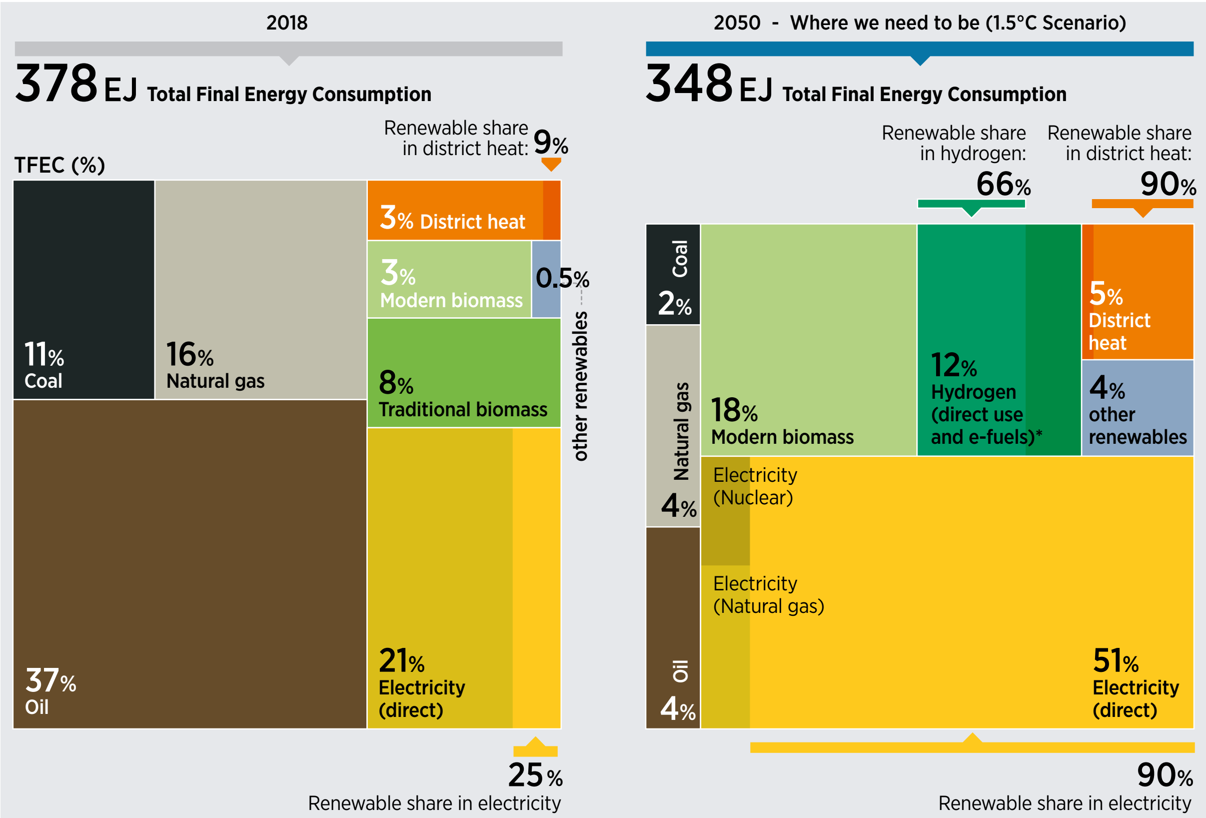


Note: RE = renewable energy ; 1.5-S = 1.5°C Scenario.

In the 1.5°C Scenario, the total final energy consumption in 2050 would be 8% below 2018, despite significantly higher population and GDP growth over the three decades. Electricity would become by far the largest energy carrier, nearly twice as large as all remaining oil and gas final consumption. The share of direct use of electricity in final end use consumption would increase from 20% to almost 50% in 2050; as a result, gross electricity consumption would more than double by 2050.

Photo: konstantinks / Shutterstock.com

Figure 23 Total final energy consumption by energy carrier in 2017 in the TES, 2050



Notes: The figures above include only energy consumption, excluding non-energy uses. For electricity use, 25% in 2018 and 90% in 2050 are sourced from renewable sources; for district heating, these shares are 9% and 90%, respectively; for hydrogen (direct use and e-fuels), the renewable energy shares (i.e. green hydrogen) reach 66% by 2050. The category "Hydrogen (direct use and e-fuels)" accounts for total hydrogen consumption (green and blue) and other e-fuels (e-ammonia and e-methanol). Electricity (direct) includes all sources of generation: renewable, nuclear and fossil fuel based. TFES = total final energy supply.

The transport sector, currently dominated by direct fossil fuel use, undergoes a profound transformation in the 1.5°C Scenario. The share of electricity in all transport sector energy rises from just above 1% in 2017 to 49% in 2050. The number of EVs increases from around 8 million in 2019 to close to 1.8 billion in 2050.

The buildings sector today consumes proportionately more electricity than all other end-use sectors, with electricity accounting for about 32% of final energy consumption. Fossil fuels in this sector are mainly used for heating and cooking. In the 1.5°C Scenario, electricity's share of final energy consumption in buildings grows to about 73% by 2050. For heating, the number of electric heat pump units in operation increases from around 38 million today to over 290 million units by 2050. In addition, shifting from fuel combustion to more efficient electricity in cooking, such as by using induction stoves, can cut the total energy demand for cooking by three to five times.

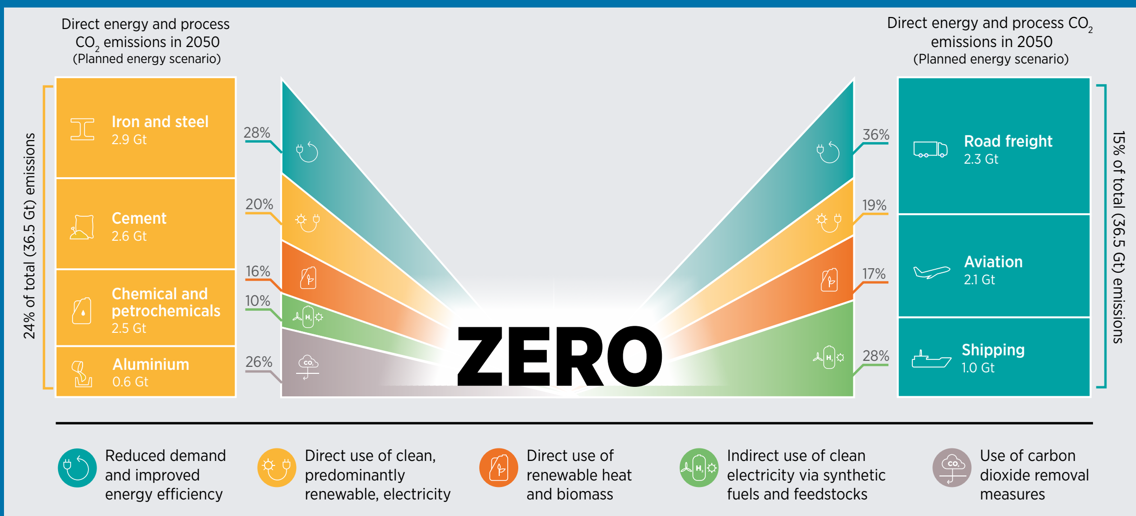
Industry is the most challenging sector to electrify in the long term. Electricity currently accounts for about 28% of final energy consumption in industry. In the 1.5°C Scenario, this share would grow to 35% by 2050. That increase is made possible by using efficient heat pumps for low-temperature heat and by directly electrifying certain processes. By 2050, 80 million electric heat pumps could be installed to meet about 7% of global industrial heat demand (more than 400 times the number in use today). Indirect electrification via hydrogen will also play an important role; hydrogen derived from renewables can be used to replace natural gas and to produce chemicals. The use of clean hydrogen to replace fossil fuel-based feedstocks and process heat (e.g. in iron and steel, methanol and ammonia production) increases to 38 EJ by 2050.

Box 13. **Reaching zero with renewables – important additional measures**

As the scientific understanding of climate change has deepened and as societal and political awareness has grown, the urgency of tackling all CO_2 emissions has also become evident. A growing number of countries have thus turned their attention to the 1.5°C limit, which means eliminating emissions in all sectors of the economy. IRENA's *Reaching Zero with Renewables* study (2020c) explores how the world could achieve zero emissions in key industry and transport sectors by around 2060.

Figure 24 provides a high-level view of how a combination of five emission reduction categories could, if applied at scale, reduce industry and transport CO_2 emissions to zero

Figure 24 **Emission reduction measures to reduce selected industry and transport CO_2 emissions to zero**



The *Reaching Zero* report reflects the significant progress that has been made in recent years in understanding the potential for electrification in so-called hard-to-decarbonise sectors of industry and transport. Some of the options explored would have been dismissed just a few years ago due to prohibitive costs. However, the dramatic decrease in renewable electricity prices has changed the paradigm, and there is now increased attention on solutions to reach zero emissions based on renewable electricity. While all of these options look to be technically feasible, each has various barriers that need to be overcome. Determining the detailed role and implications of these electrification options will require further analysis, which IRENA expects to carry out in the coming years.

In industry, promising electrification options are already identified in renewables-based hydrogen for iron and steel, using synthetic hydrocarbons for feedstocks and renewables for energy in chemicals and petrochemicals, switching to renewable sources of electricity for cement production, and integrating heat pumps and renewable electricity in aluminium production. In transport, promising electrification options are identified in both battery EVs and FCEVs in road freight, e-fuels and electric propulsion in aviation, and hydrogen and e-fuels in shipping.

Although direct use of renewable electricity still plays a major role in decarbonising hard-to-decarbonise industry and transport sectors, options that make use of green hydrogen and its derivative e-fuels are relatively more prominent in these particular areas. In the chemical and petrochemical sector, for example, the report cites recent work that anticipates green hydrogen production capacity increasing to 1 000 GW by 2050, and the overall sector shifting to 3 000-6 000 GW of renewable power in order to achieve complete decarbonisation. These options would constitute a substantial amount of the total investment of USD 9.6 trillion needed by 2050 in the sector, equivalent to 8% of all energy sector investment needed to reach the Paris Agreement's climate goals.

Box 14. **Measuring the level of electrification**

As a primary indicator for measuring the degree of electrification in end-use sectors, the share of electricity use in final energy consumption is a common metric. In this metric, the role of green hydrogen (which is produced from carbon-free electricity through electrolysis) is not fully captured. Two alternative measures could be considered instead. To capture the possible role of hydrogen produced from renewable energy, hydrogen use in final energy consumption can be counted as pseudo-electricity. IRENA work takes this approach. Another possible measure is to include non-energy use of fuels (e.g. feedstocks for industrial processes) in the total energy value, and reflect the possible substitution of fossil use for non-energy applications by hydrogen and its derivatives. Another supplementary indicator is the share of fuels used for power generation in the total primary energy supply. Although statistical convention determines the way in which primary energy contributions from renewable energy are measured, increasing end-use sector electrification would reduce the direct use of fossil fuels, while the shift to renewables from fossil fuels in power generation would decrease the overall primary energy supply.

3.2 ELECTRIFICATION IN SGERI'S SCENARIO STUDY ON MEDIUM- AND LONG-TERM ENERGY AND POWER SECTOR DEVELOPMENT IN CHINA

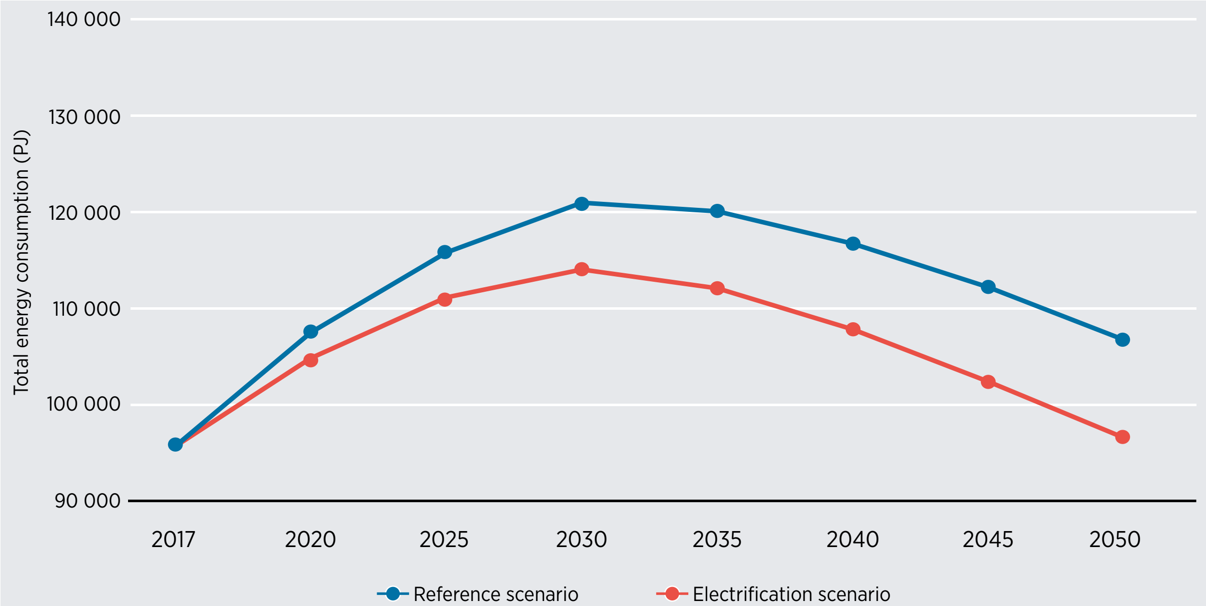
To help plan China's long-term energy and power development, the SGERI constructed an integrated economy-energy-environment analysis model based on the Unified Global Energy Research Platform. The model includes forecasts of economic development and end-use energy demand, simulations of power system planning, and estimates of primary energy demand and carbon emissions (see Appendix VII for further detail on methodology and assumptions).

Based on SGERI's China Energy & Electricity Outlook (SGERI, 2019) work, this report compares the Reference Scenario from that exercise out to 2050 with an "Electrification Scenario", which explores a more extensive penetration of electrical end-use technologies and low-cost renewable energy.

END-USE ENERGY DEMAND

In the Electrification Scenario, end-use energy demand peaks around 2030 at about 114 042 PJ, which is lower than the peak of 120 968 PJ in the same year of the Reference Scenario. In addition, demand falls faster after reaching its peak in the Electrification case than in the Reference Scenario.

Figure 25 Total end-use energy demand in two scenarios, 2017-2050



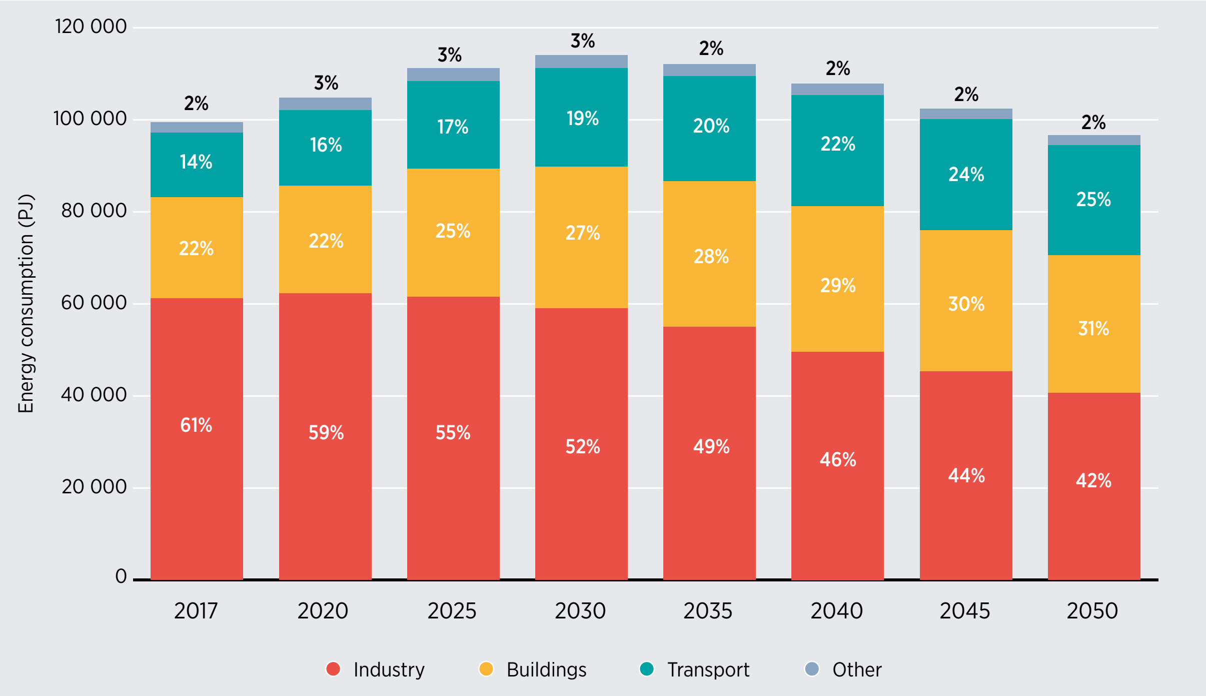
In the Electrification Scenario, the share of energy consumed in the industrial sector decreases faster than that in the Reference Scenario due to efficiency improvements with greater use of electricity, while the share of energy consumed in the buildings sector increases more quickly. In 2030 the division of energy use across industry, buildings and transport is 52%, 27% and 19%, respectively. In 2050 the division of consumption between the three is 42%, 31% and 25%, respectively.

The share of energy consumed in the industrial sector plateaus in 2025 in both scenarios, as the major energy-consuming industries (such as steel, chemicals, non-ferrous metals and architectural materials) reach estimated peak production while also incorporating improvements and upgrades in capacity structure and production processes. In the Electrification Scenario, industrial energy peaks at a lower level and decreases faster than in the Reference Scenario because of greater electricity-based energy consumption from higher use of electric boilers, electric kilns and heat pumps.

The share of energy consumed in the buildings sector continues to grow, becoming the main contributor of growth after 2030. It reaches a peak value about 31 657 PJ around 2035, about 1.4 times higher than in 2017. After 2035 slower growth in construction and energy efficiency improvements lead to declines in the sector's energy consumption in both scenarios. But the decline is more rapid in the Electrification Scenario because of greater use of heat pumps and other highly efficient end-use technologies. Meanwhile, growth in the service industry raises the percentage of energy consumed in the public and commercial buildings sector compared to the housing sector. In the Electrification Scenario, the percentage of the energy consumed in the public and commercial buildings sector rises from 34% in 2017 to a peak of 44% in 2030, and then declines slowly to 40%.

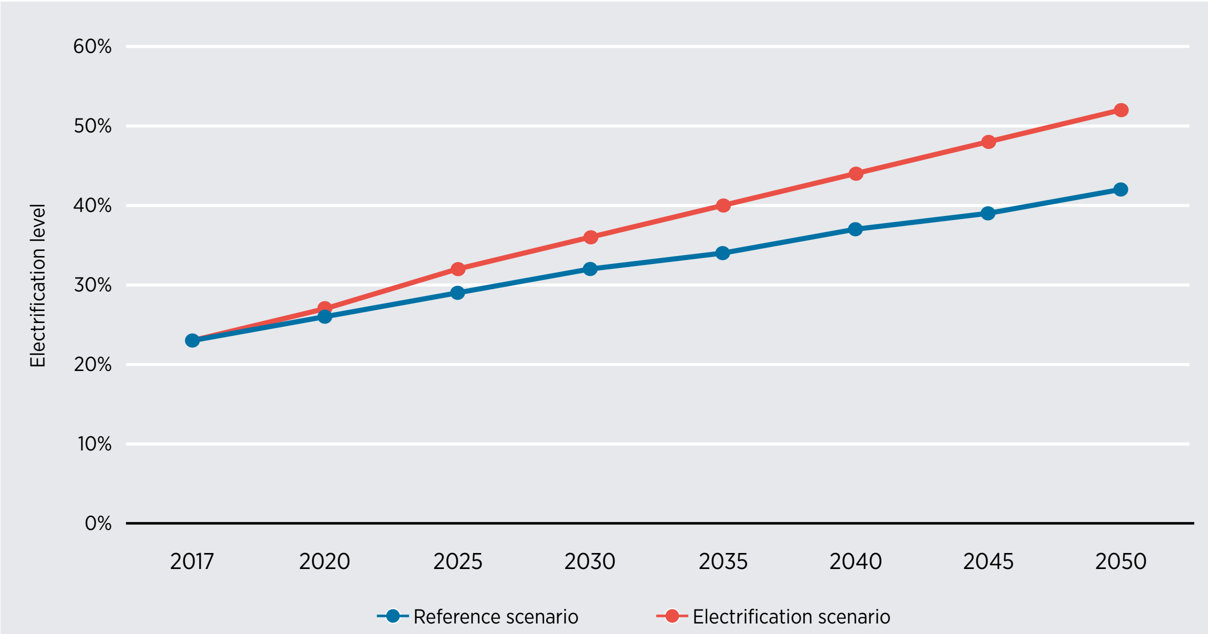
The share of energy consumed in the transport sector climbs relatively quickly, and the sector becomes the main contributor to energy growth after 2030. Energy consumption for transport in 2035 is 1.8 times higher than in 2017, rising to 1.9 times higher in 2050. In the Electrification Scenario, more EVs replace fossil fuel cars, which improves the efficiency of energy end use. Thanks to improvements in fuel economy and system efficiency in the Electrification Scenario, energy consumption from highway traffic (including urban transport systems) decreases from 79% of total transport energy in 2017 to 77% in 2035, and to 69% in 2050. The share of energy use for passenger transport alone declines from 62% in 2017 to 43% in 2035, and 40% in 2050. Meanwhile, energy use for aviation is four times higher in 2050 than in 2017.

Figure 26 End-use energy demand in various sectors in the Electrification Scenario, 2017-2050



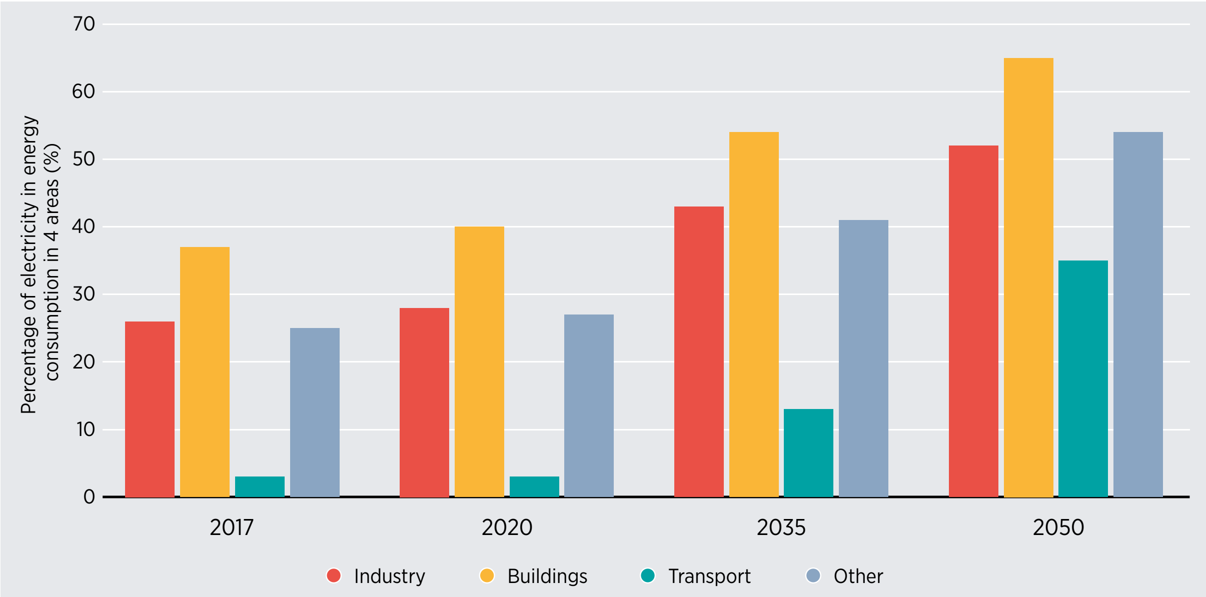
One key difference between the Electrification Scenario and the Reference case is the greater increase in the share of electricity in total end-use energy demand. In the Electrification Scenario, electricity supplies 27% of total energy use in 2020, 36% in 2030 and 52% in 2050, compared to about 32% in 2030 and 42% in 2050 in the Reference case.

Figure 27 Overall electrification level in two scenarios, 2017-2050



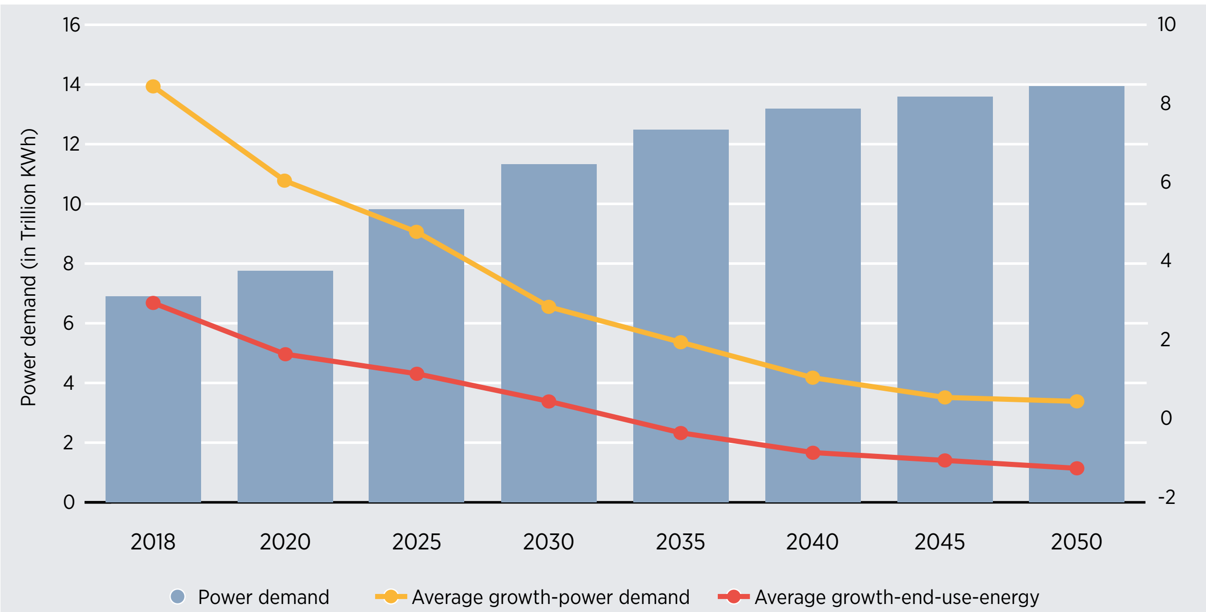
The buildings sector is the largest current user of electricity, and this continues to be the case in both the Electrification and Reference Scenarios, but the increase is larger in the Electrification Scenario, with an electrification rate of 65% by 2050. In the transport sector, the electrification rate increases from the 2017 level of 3% to 35% in 2050 with Electrification. In the industrial sector, the share of electrification reaches 52% in 2050, also higher than in the Reference Scenario.

Figure 28 Electrification rate of various sectors in the Electrification Scenario



Naturally, electricity demand and its rate of growth are higher in the Electrification Scenario compared to the Reference case. Total electricity demand is around 11.3 trillion kWh in 2030 and 13.9 trillion kWh in 2050. The annual rate of increase falls below 2% after 2035.

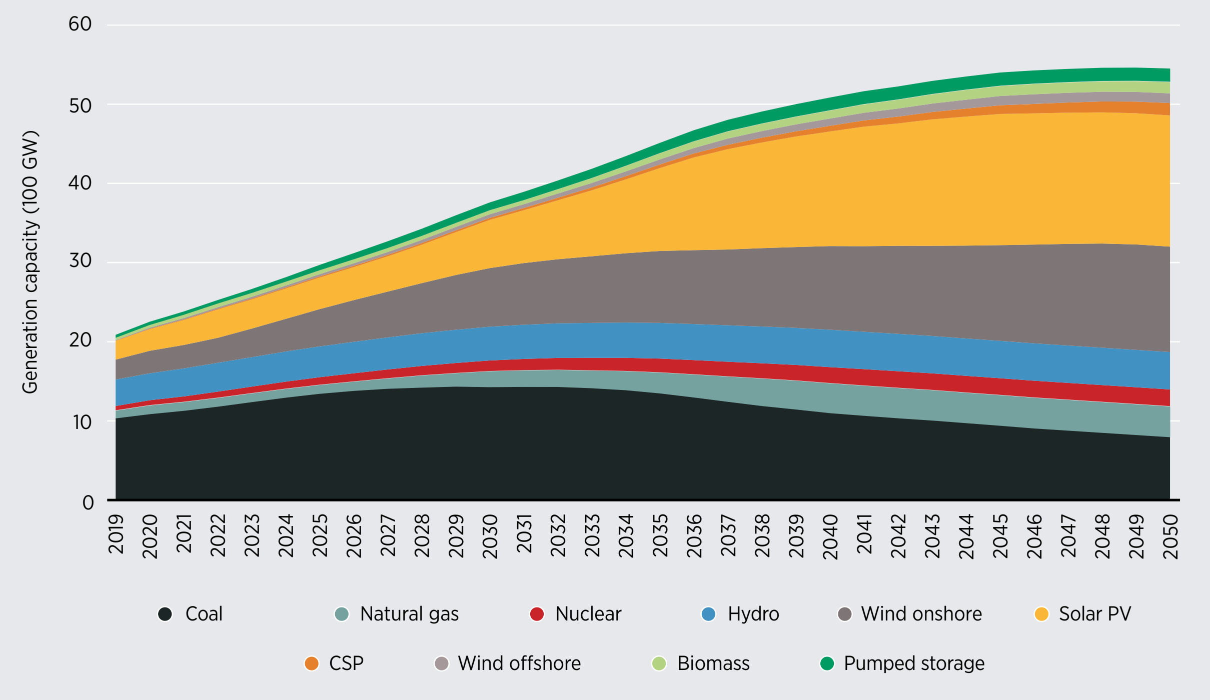
Figure 29 Electricity demand in the Electrification Scenario



POWER SOURCE STRUCTURE

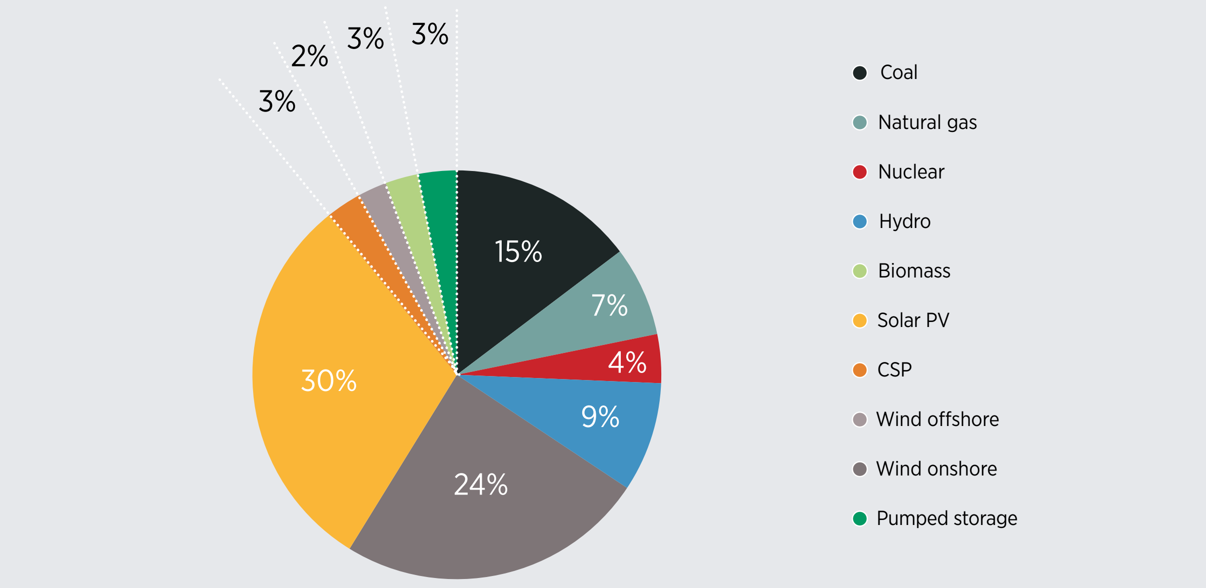
The capacity to supply electric power is expected to significantly increase. Up to 2050 installed capacity grows rapidly, with a higher growth rate in the Electrification Scenario than in the Reference Scenario. In 2050 installed capacity reaches 5.45 TW, with 4.26 TW of clean power sources, which is higher than in the Reference Scenario.

Figure 30 Generation capacity of various power sources in the Electrification Scenario, 2019-2050



Onshore wind and PV are the fastest-growing power sources, and growth rates are highest in the Electrification Scenario. In this scenario the installed capacity of onshore wind power reaches 1.33 TW in 2050, with 1.66 TW for PV. The capacities of nuclear power and hydro power are respectively 0.21 TW and 0.47 TW in 2050, similar in both scenarios. The capacities of coal power and gas power are 0.80 TW and 0.39 TW in 2050 in the Electrification Scenario, slightly higher than the levels in the Reference Scenario, due to the larger amount of electricity demand to be met.

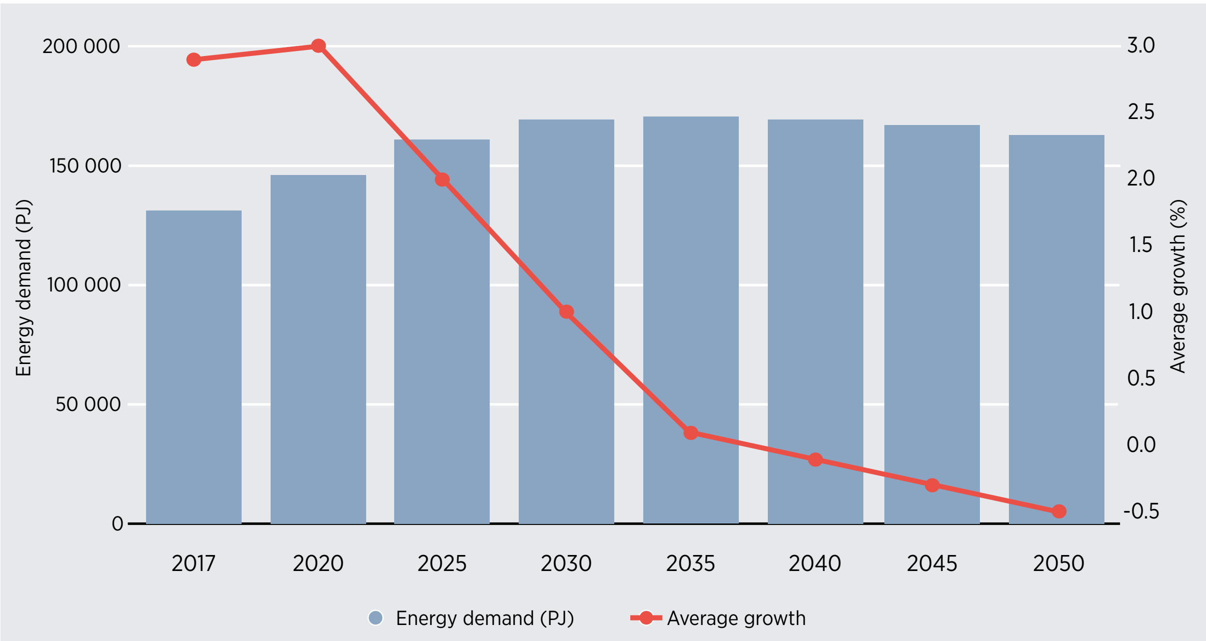
Figure 31 Share of various power sources in the Electrification Scenario, 2050



PRIMARY ENERGY DEMAND

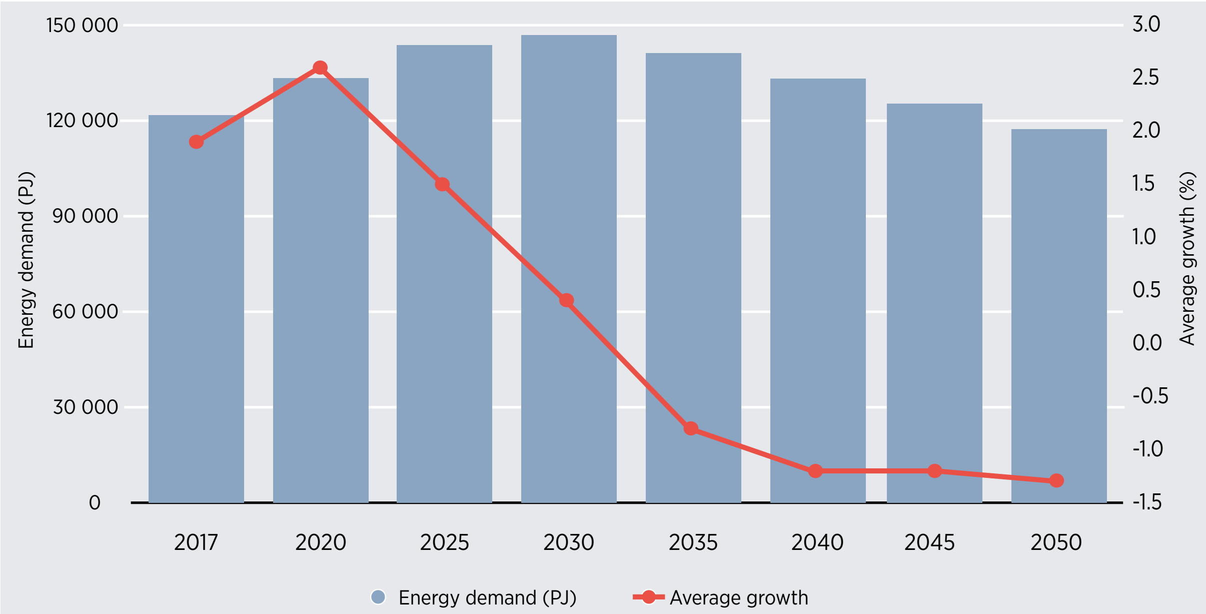
In the Electrification Scenario, where demand for primary energy is lower than in the Reference Scenario, primary energy demand grows from 162 874 PJ in 2030 to 170 548 PJ in 2050. The peak value appears around 2035.

Figure 32 Total primary energy demand in the Electrification Scenario (by coal-equivalent calculation approach), 2017-2050



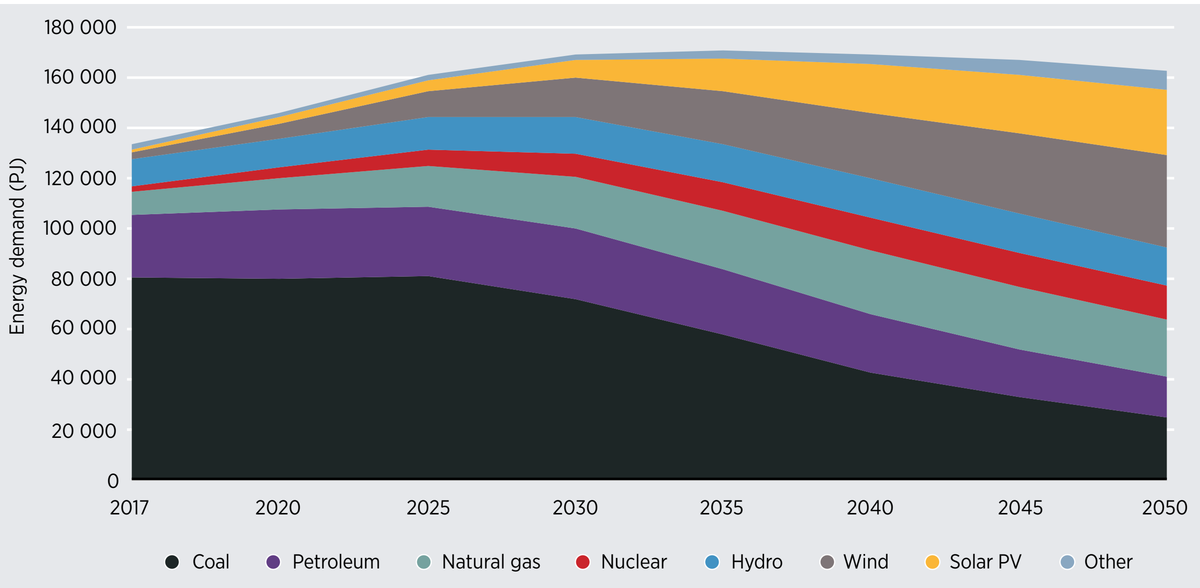
By using the calorific value calculation approach, primary energy demand is evidently lower. The peak value is approximately 146 836 PJ, which appears around 2030. After that, the level of primary energy demand decreases substantially, to around 117 405 PJ in 2050. Primary energy demand in the Electrification Scenario is much lower than in the Reference Scenario.

Figure 33 Total primary energy demand in the Electrification Scenario (by calorific value calculation approach), 2017-2050



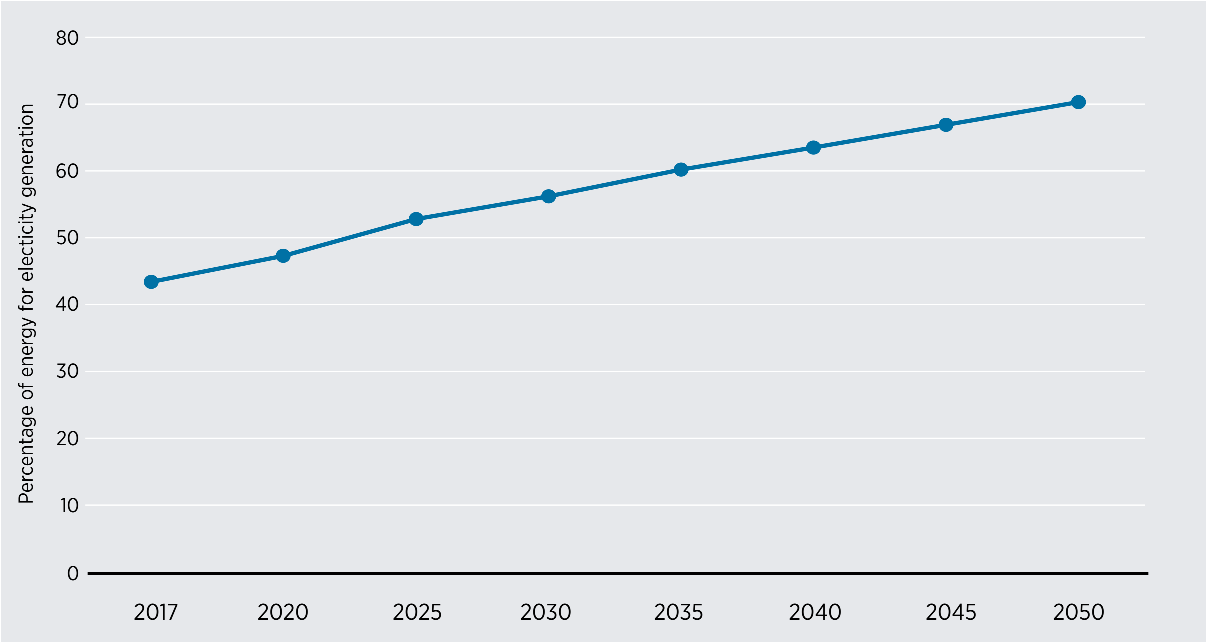
In the Electrification Scenario, the transition to low-carbon energy occurs faster than in the Reference Scenario. The percentage of coal in supplying primary energy demand drops to about 15% in 2050, the share of oil falls to 10% and the share of natural gas falls to 14%. The share of non-fossil energy sources reaches 61% in 2050.

Figure 34 Primary energy demand of various sources in the Electrification Scenario, 2017-2050



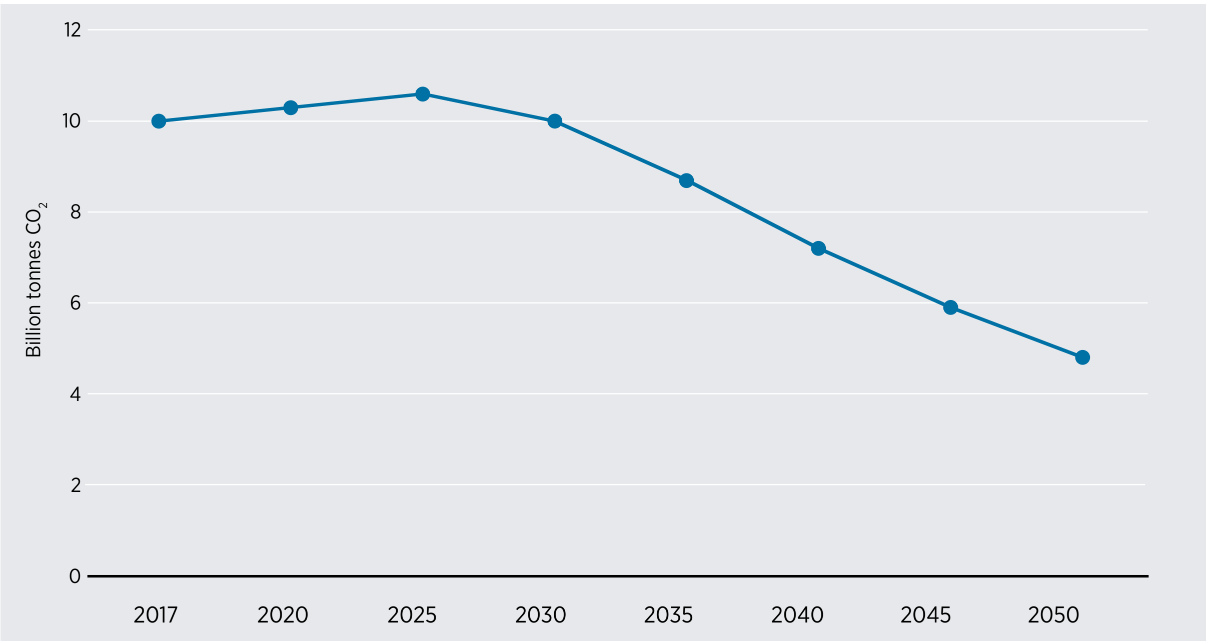
As end-use energy electrification increases, energy for electricity generation commands an increasing share of primary energy demand, climbing to 56.2% in 2030 and 70.3% in 2050.

Figure 35 Share of energy used for power generation in primary energy demand in the Electrification Scenario, 2017-2050



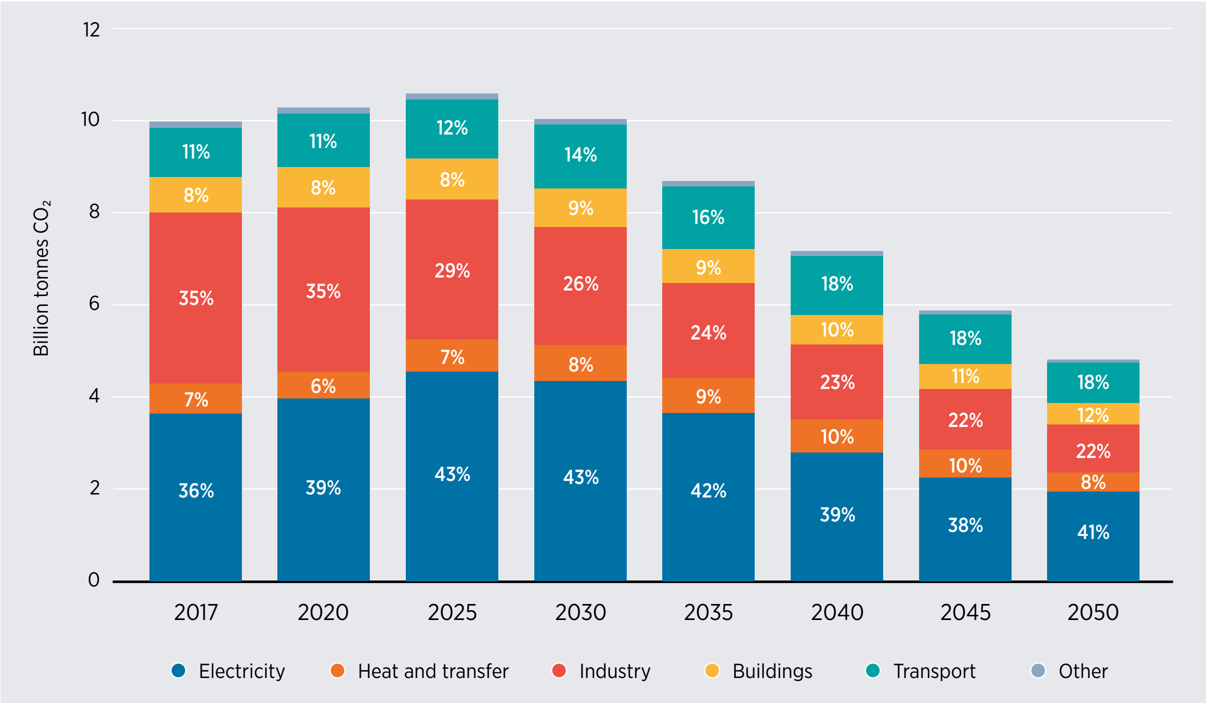
In the Electrification Scenario, CO_2 emissions are lower compared to those in the Reference Scenario, reaching a peak of 10.6 billion tonnes in 2025 and declining to 4.8 billion tonnes in 2050.

Figure 36 Energy-related carbon emissions in the Electrification Scenario, 2017-2050



Electrification will cause more carbon emissions to be transferred from end-use sectors to the power generation sector. By about 2025, both the total amount of electrical-sector carbon emissions and its share are expected to peak, at levels even higher than the emissions from the industrial sector, making the electrical sector the largest source of carbon emissions. In the Electrification Scenario, electrical-sector carbon emissions are expected to reach their peak at a higher level than in the Reference case due to more carbon emissions shifting from end-use sectors to the power sector, since less fossil fuel is used by customers on the demand side. Therefore, even though the scale of power sector carbon emissions is higher, electrification will make a greater contribution to overall carbon emission reductions by reducing the carbon emissions of end-use sectors.

Figure 37 Carbon emissions of various sectors in the Electrification Scenario, 2017-2050



4 FUTURE PRIORITIES ON THE PATHWAY TO SMART ELECTRIFICATION WITH RENEWABLES

KEY MESSAGES

- While policy makers have gained significant experience of developing frameworks for renewable power and specific electrification options, such as electromobility, insufficient attention has been paid to the policies that will create synergies between them.
- Electrification strategies should be part of national energy plans. Electrification roadmaps should consider local characteristics, e.g. climate conditions, population density and consumer preferences, as well as future infrastructure needs to address the impact of electrification on the electricity load profile, e.g. impacts on T&D grids, number and location of EV charging stations, and areas with possible congestion issues.
- National electrification plans should promote smart electrification strategies, such as smart charging of EVs, aggregation of electric boilers and heat pumps, and energy storage that provides flexibility to the power system. Inclusion of these strategies incentivises engagement with the private sector and consumers, and delivers more cost-effective solutions.
- Many smart electrification solutions are already available, and pioneers are showing what can be done. Better understanding of ongoing demonstration projects and international practitioners can be valuable for the design of enabling frameworks.
- The technology and infrastructure needed for electrification are understood, but markets must be well-designed alongside them. Markets should be designed in ways that promote system-friendly deployment strategies. Currently, consumer prices in most markets do not provide the necessary incentives. Forward-looking and flexible market design is essential to foster innovation.
- Electrification should exploit digitalisation in order to harness essential synergies between renewable electricity generation and electricity end use. This will enable smarter, better connected and more reliable future systems.
- Renewables-supplied electrification will be the primary route for decarbonising transport, buildings and industrial energy use if done smartly. Electromobility, electric heating and cooling, and hydrogen production are three critical components of electrification. Each market segment requires the deployment of dedicated policy instruments.

- The characteristics of end-use sectors and technologies vary. While heating has a strong seasonal component, for example, this is not the case for transport. These aspects must be considered as the potential of electrification is fully explored.
- For industry, significant potential exists to relocate and co-locate energy-intensive industries to remote locations with abundant low-cost renewable energy. Such transitions will only happen if proper economic incentives are put in place and if the technology matures.
- Innovation has the greatest impact when it reflects the needs and wishes of consumers and communities. Technical ease of use and economic viability are vital aspects. Policies should be designed to promote solutions with these aspects in mind.

4.1 INTRODUCTION

The analyses in this report indicate that electrification can grow rapidly in transport, buildings and industrial energy use. And with renewables dominating the electricity supply, electrification can potentially decarbonise a large share of energy demand in the process.

Increased electrification will create new challenges – for example, in supply or new load profiles – but also new opportunities – for example, new flexibility options. To minimise issues and maximise benefits over the course of the transition, it is imperative that increased electrification is planned carefully and delivered intelligently. For many policy makers, this will be new territory: while many have significant experience of developing frameworks to enable renewable power and specific electrification options such as electromobility, often little attention is paid to policies that will create synergies between both aspects.

Successful electrification will thus require two actions in particular: first, delivering strategies that electrify in a smart way by harnessing the synergies between the consumption of clean power and the integration of high shares of VRE (e.g. smart charging of EVs, electricity storage providing grid services, aggregation of heat pumps and electric boilers for demand response, and use of surplus VRE power for H_2 electrolysers); and second, developing a better understanding of the possible technical limitations of electrification in different sectors over time to avoid power system disruption or unbearable costs.

Through the efforts of many pioneering governments and companies around the world, much of the knowledge and many of the innovative solutions needed for the smart electrification transition already exist. However, to ensure secure energy access and to tackle climate change, uptake needs to be accelerated and broadened well beyond the pioneers, as well as being tailored to local needs. Policy makers have a critical role to play in making this happen, and ensuring that the expansion of renewable power generation and the electrification of end uses follow a path that is mutually beneficial.

A selection of priorities for action is outlined below.

4.2 PRIORITIES AND ACTIONS FOR POLICY MAKERS

Table 6 below provides an overview of seven priorities that policy makers should consider when developing strategies for the electrification of end-use sectors with renewables.

Table 6 Priorities and actions for future expansion of smart electrification

Priorities		Action
Planning, Market Design, Societal Focus		
1. Planning: Recognise that electrification tomorrow requires investment in infrastructure today – electrical and digital	Although the transition will take time, enabling infrastructure must be put in place now. The smart electrification transition is particularly reliant on intelligent planning and investment in improved infrastructure networks Smart digital infrastructure networks and technologies for power grids and buildings are central to reducing infrastructure costs and delivering more optimised charging, metering and communication with end-use sectors	Develop roadmaps for smart electrification infrastructure, including T&D grids, charging infrastructure, and networks for hydrogen transport and district heating/cooling expansion Support pilots for digitally enabled solutions to address the challenges of new load profiles
2. Market design: Address the need to shape or create proactive markets that deliver flexibility and economic incentives	If system-wide end-use sector flexibility is not reflected in regulations or properly rewarded, it cannot emerge. Retail and wholesale markets should be designed to recognise the economics of key electrification technologies and strategies, and how they will evolve across sectors with trends such as digitalisation and decentralisation	Adapt regulations to expose consumption to price signals, through measures like time-of-use tariffs Remove barriers to innovative technologies and ownership models, to allow participation in multiple markets
3. Societal focus: Reflect the needs and wishes of consumers and communities	Increased decentralisation of energy resources, and local ownership and awareness of the environmental implications of energy production are changing the ways in which people engage with the energy system. Consumers and communities must be involved with and benefit from electrification efforts, otherwise there is risk that the transition will face justified pushback	Engage citizens across the dimensions of choice, participation, governance and responsibility Gather better insights into consumers' needs and expectations, and tailor solutions accordingly Understand how legacy infrastructure and producers will be affected by the shift to electrification with renewables, and develop adequate economic policies to ease the impacts of the transition if necessary

Priorities		Action
Technology		
4. Promote solutions in transport: Take advantage of EV-VRE synergies and advance niche R&D to electrify other modes	E-mobility will grow rapidly in the coming decades, which means it is critical to already understand how EV demand will affect power system supplies, system operation and smart charging opportunities While electrification of passenger cars, delivery trucks and buses is progressing, the future of other hard-to-decarbonise segments of the transport sector – such as long-distance shipping and aviation – remains unclear	Scale up smart charging infrastructure, assess and plan the electric infrastructure needs, particularly at distribution level, to avoid bottlenecks Support pilot projects that explore vehicle-to-grid technology and business models Continue applied R&D to explore high-potential electric storage and fuel options in shipping and aviation
5. Promote solutions in buildings: Exploit existing solutions by introducing standards, codes and regulation to speed up and scale up deployment	The technology to increase renewable electricity in buildings' energy consumption – and ensure that consumption is highly efficient – largely exists: heat pumps, electric boilers, advanced building envelopes and district heating infrastructure can cover a wide range of small- and large-scale applications. However, actual deployment of efficiency measures and existing technologies is too sluggish in most markets	Incentivise the deployment of heat pumps and electric boilers Act on opportunities for large-scale centralised solutions through district heating/cooling and thermal storage. Also consider the use of renewable electricity coupled with electric boilers and thermal storage Ensure building codes require highly efficient building shells in new infrastructure Fund or incentivise the rollout of smart metering and appliance infrastructure in both new and existing building stock
6. Promote solutions in industry: Push sector-specific R&D and demonstration, with a long-term global perspective	Electrification of industry is lagging behind that of transport and buildings in most contexts due to the costs and unique industrial requirements. However, targeted industry electrification solutions can quickly become major breakthroughs given the bulk of industrial energy use is for only a few energy-intensive commodities	Support more R&D and demonstration for the direct and indirect use of electricity in industrial processes Explore relocation and co-location of energy-intensive industry to sites with low-cost, high load factor renewable electricity Pursue global co ordination to ensure a level playing field and avoid carbon leakage
7. Electrified fuels: Understand their long-term roles and economics	Using renewable electricity to produce hydrogen or other synthetic fuels can potentially play a range of key roles in the smart electrification process, e.g. as a complement to direct electrification for hard-to-decarbonise areas, as a means of flexibility and seasonal storage for VRE integration, and as a possible avenue to avoid stranding of existing gas transport assets	Establish a policy framework which provides clarity for infrastructure investment and improves economics across the entire supply chain Expand the availability of low-cost, ideally high load factor, renewable electricity

1. PLANNING: RECOGNISE THAT ELECTRIFICATION TOMORROW REQUIRES INVESTMENT IN INFRASTRUCTURE TODAY – ELECTRICAL AND DIGITAL

As discussed throughout this report, it is clear the electrification process will be a systemic transition and therefore requires a range of cross-cutting foundations. **Although the transition will take time, the enabling energy, ICT and urban infrastructure must be put in place now.** The smart electrification transition is particularly reliant on intelligent planning and investment in improved infrastructure networks – e.g. **reinforcement of T&D grids, charging networks for electromobility, and pipelines for hydrogen transport and district heating/cooling expansion.**

Digitalisation is unique in this space as it has potential to influence – and, critically, to improve the quality of – infrastructure operation and stakeholder interaction with infrastructure across the board. **Smart digital infrastructure technologies and networks in grids and buildings are key to delivering lower-cost and more optimised charging, metering and communication with end-use sectors.** The disruptive potential of digital solutions is only beginning to be understood and is far from being fully exploited.

High rates of electrification in end-use sectors bring new load profiles, for example new locations and usage rates of EV charging stations. The impact of these new load profiles on electricity systems, for example extreme peak demand, seasonality and congestion on grids, needs to be well understood to devise smart electrification strategies. Given the uncertainty around stakeholder behaviour in these new networks, **policy makers should develop roadmaps for electrification infrastructure** at regional and national levels to explore sensitivities and limitations in the expected levels of electrification over time and across sectors. Many **more pilots and deployment of digitally enabled solutions should be supported by governments** in a wider range of circumstances to improve understanding of how they can and will be used.

Box 15. **Examples of planning for electrification**

California, United States – Realising the importance of the transport sector to the state's decarbonisation plans, California has established ambitious goals for the expansion of zero emission vehicles (ZEVs), with a deployment target of 5 million ZEVs by 2030 (versus ca. 400 000 ZEVs and 25 million total registered automobiles in 2017) (California Air Resources Board, 2018). The state government has realised that such an expansion has major planning implications, however, and has complemented targets with USD 2.5 billion over eight years to install 250 000 charging stations, and has directed state agencies to co-ordinate planning of sufficient new infrastructure and provide transparency to stakeholders (Reuters, 2018). New forward-looking legislation has also been passed to commit the state to 100% carbon-free electricity by 2045, ensuring that new electricity demand from transport will not mean long-term increases in fossil-fuelled power production (California 100% Clean Energy Coalition, 2018).

The state's efforts are supported by a vibrant ecosystem of pilot projects being carried out by proactive utilities and private-sector companies to explore digitalisation and flexibility in expanding e-mobility resources. For example, Pacific Gas & Electric and BMW have successfully tested the potential for EVs to participate in demand response events, and San Diego Gas & Electric has tested simple time-of-use tariffs and dynamic hourly pricing as drivers for both smart charging and vehicle-to-grid services from EV fleets (IRENA, 2019f).

Hamburg, Germany – To plan for the anticipated adoption of EVs, the distribution system operator for the city of Hamburg is looking into the impact they may have on the city's grid. It found that ca. 15% (ca. 800) of the feeders analysed on its distribution system could face bottlenecks (i.e. congestion issues) for anticipated EV expansion (IRENA, 2019f). To avoid very costly infrastructure reinforcement, the organisation is now working with Siemens on a smart digital solution to manage this new load.

2. MARKET DESIGN: ADDRESS THE NEED TO SHAPE OR CREATE PROACTIVE MARKETS THAT DELIVER FLEXIBILITY AND ECONOMIC INCENTIVES

Alongside large-scale investments in infrastructure networks – which are often naturally co-ordinated in a centralised manner – it will be important to design intelligent policy and regulation to ensure electricity markets deliver the flexibility required at various scales for many smart electrification strategies. System-wide **end-use sector flexibility needs to be properly rewarded or it cannot emerge,** and reforming regulations to **expose consumption to price signals**, for example through measures like time-varying tariffs at both the retail and wholesale level, can **create an economic case for key electrification technologies and strategies**, for example smart charging, aggregation and "energy as a service" business models, and arbitrage or demand response provision by electric and thermal storage.

In designing markets, **the economics of different electrification options must always be in sight;** they vary widely (e.g. EVs vs hydrogen or electrified synthetic fuels) and their evolution should always be considered. In this process it is critical to understand how market incentives will interact with equally important non-market measures such as mandates, obligations and taxes, with transparency around when those complementary measures will be phased in and out.

Economic reforms can be complemented by clarifying regulations around participation in markets as well, to **remove barriers to innovative technologies or ownership models, and encourage wide stakeholder participation** from consumers, distribution and transmission system operators and utilities. For example, the ability for EV batteries – whether individually or aggregated by grid operators – to participate in multiple markets like those for ancillary service or balancing is likely to be critical to provide sufficient economic incentives for smart charging. Providing services across different end-use sectors may also require regulatory changes, even if the large-scale enabling infrastructure required to do so is in place.

Box 16. **Examples of market design for electrification**

Denmark – the "eFlex" project conducted by Ørsted Energy assessed the potential peak load reduction from using heat pumps exposed to price-based demand response programmes. Heat pumps can be attached to smart devices that can control the functioning of the heat pump, thus benefiting consumers as well as grid operators in managing demand. The system was designed so that a heat pump would reduce its consumption or shut off during peak demand intervals (if the house is sufficiently heated) and turned back on during low demand intervals. The results from this study indicated that optimising the heat pump's performance resulted in reducing the peak load by 47-61%, depending on the time of day and prevailing temperature conditions (IRENA, 2019b).

New York, United States – In December 2017 the New York Independent System Operator released "Reforming the Energy Vision", a market design proposal that would overhaul the treatment of distributed energy resources, such as electricity loads or storage in buildings (IRENA, 2019b). As per the current framework, distributed energy resources can only provide retail services to distributed system platforms. The proposal would treat them on a par with other wholesale market resources by fully integrating them with the energy and ancillary services markets. Under the proposed framework, they will also be able to participate in wholesale markets, such as capacity markets, energy markets and regulation service markets, either directly or via aggregators of small-scale distributed energy resources (< 100 kW).

3. SOCIETAL FOCUS: REFLECT THE NEEDS AND WISHES OF CONSUMERS AND COMMUNITIES

Greater decentralisation of energy resources, local ownership and awareness of the environmental implications of energy production are changing the ways in which people engage with the energy system. **Consumers and communities must be involved with and benefit from electrification efforts, otherwise there is risk that the transition will face justified pushback.** Ensuring that electrification occurs in a fair and inclusive way can require action across four main dimensions of engagement: choice, participation, governance and responsibility.

However, there is still a limited understanding of how end users will – or would like to – interact with the future energy system, and current operating models do not always reflect the needs of citizens or the potential role of active consumers. **Governments and companies need to gather better insights into consumers' needs, expectations and their willingness to adopt innovations,** and should tailor solutions accordingly. Some consumers are likely willing to play an active role in the energy system, but the benefits must be clear and automation is needed to make responses simple.

Box 17. **Example of societal focus in electrification**

Illinois, United States – Customers of Consolidated Edison, a utility operating in the United States, were given the option to participate in an hourly pricing programme, where electricity prices were reflective of the electricity load (i.e. prices were low during the low demand period and high during the high demand hours) (IRENA, 2019k). An example of demand shifting by consumers includes pre-cooling the house in early morning hours, when prices are lower, and setting the cooling systems to an idle mode when prices are higher. The programme has allowed consumers to save about 15% on their electricity bills (a total of USD 15 million from 2007 to 2016).

4. TRANSPORT: TAKE ADVANTAGE OF EV-VRE SYNERGIES AND ADVANCE NICHE R&D TO ELECTRIFY OTHER MODES

In many global contexts, the favourable economics of e-mobility – particularly for passenger vehicles – have now taken over as the primary driver of transport sector electrification. It is expected that electromobility will grow rapidly in the coming decades. This means it is critical to **understand how EV demand growth will affect power supplies and power system operation, and how this transition can take place in a way that is beneficial for both electromobility growth and renewable power generation growth.**

Smart charging will be crucial in this regard, and wise planning across power and transport sectors will be key to support it. **Deployment of smart charging infrastructure should be scaled up to avoid becoming a bottleneck** that slows the transition, but the composition of that infrastructure network must be well understood to avoid costly over- or under-construction. Home and office charging will clearly be essential complements, but smart charging will occur in a wider, more complex landscape that could also include charging at different speeds, scales and times depending on consumer behaviour. **The nature of the charging landscape should be planned for and understood** in relation to power sector operation and cross-sector regulation. **Intelligent market design can complement good planning across sectors to enable systemic flexibility** – through dynamic pricing, for example – and pilot projects that explore vehicle-to-grid technology and business models should continue to be encouraged.

While the electrification of passenger cars, delivery trucks and buses is progressing, the future of other hard-to-decarbonise segments of the transport sector – such as long-distance shipping and aviation – remains unclear. **Applied R&D should continue to explore high-potential electric storage or fuel options** with those segments in mind. Long-haul trucks constitute a major market segment in which manufacturers are rapidly making announcements regarding future electric offerings. Similar efforts are ongoing in various shipping applications. As new technologies are commercialised, standardisation will become increasingly important.

Box 18. **Example of smart transport electrification**

Utrecht, the Netherlands – In the Netherlands, the largest smart charging demonstration in the country has seen Dutch grid operators (through the knowledge and innovation centre for smart charging infrastructure, ElaadNL) and Renault work together to deploy 1 000 public solar-powered smart charging stations with battery storage around the region to test the potential benefits of smart charging – and even some vehicle-to-grid – infrastructure (IRENA, 2019f). The results have thus far proven substantial benefits from the potential to defer grid investment, with an increase in self-consumption from 49% to 62-87% and decrease in peak load of 27-67%.

Norway – In Norway, Avinor, the public operator of Norwegian airports, has laid out a target for all short-haul airliners to be entirely electric by 2040 (Avinor, 2018). The operator believes that developments in battery technology mean that all flights lasting up to 1.5 hours could be flown by electric aircraft, which would cover all domestic flights and those to neighbouring Scandinavian capitals. The operator plans to launch a tender to test a commercial route flown with a small electric plane starting in 2025.

5. BUILDINGS: EXPLOIT EXISTING SOLUTIONS BY INTRODUCING STANDARDS, CODES AND REGULATION TO SPEED UP AND SCALE UP DEPLOYMENT

The technology to increase the amount of renewable electricity in buildings' energy consumption – and **ensure that consumption is highly efficient** – largely exists: **heat pumps, electric boilers, advanced building envelopes and district heating infrastructure can cover a wide range of small- and large-scale applications.** Thermal storage is a newer concept, but can be used in combination with those technologies even to make use of VRE surpluses for heating. Progress in **actual deployment of efficiency measures and existing technologies is too sluggish** in most markets, however. Retrofitting and broader adoption of new building technologies or services is often hamstrung by complexities in building ownership, the timescales of building stock turnover and a **lack of standardisation, scale, and training** in smart-building technologies and service providers.

The role of policy is therefore to **speed up deployment through market creation and support. Building codes** can ensure that new infrastructure is efficient and electric – for example, by requiring highly efficient building shells. Such a push for high efficiency is needed to dampen electricity demand growth in all sectors, but it is essentially a precondition for the electrification of space heating, given the high cost of electricity relative to other energy carriers in many markets. Well-planned retail and wholesale market regulations, and a rollout of smart metering and appliance infrastructure in both new and existing building stock, can lay the foundations required for future systems that support dynamic pricing, demand response and various models of aggregation.

Box 19. **Example of smart buildings electrification**

Qingdao, China – The city of Qingdao is investing USD 3.5 billion to build a district heating network in order to eliminate the use of coal in heating (IRENA, 2019i). The district heating systems will use electric heat pumps that transfer heat from the air and ground, and the waste heat from industries, to buildings in the city. Qingdao District Heating & Power Co. is also investing in upgrading buildings to be compatible with the district heating network. The city aims to use clean energy sources for all its heating needs, which would reduce coal consumption by over 3 million tonnes per year.

Sweden – EctoGrid has developed a technology to connect the thermal flows of multiple buildings. The buildings use electric heat pumps and cooling machines to supply or withdraw heat energy from the grid. A cloud-based management system is used to balance the energy demands of all buildings connected to the grid. This results in a 78% reduction in energy required for heating systems and also reduces customers' energy bills by nearly 20% (IRENA, 2019i)

6. INDUSTRY: PUSH SECTOR-SPECIFIC R&D AND DEMONSTRATION, WITH A LONG-TERM GLOBAL PERSPECTIVE

Electrification of industry is decidedly lagging behind that of transport and buildings in most contexts. The technological solutions and service models that would allow electrification to meet unique industrial requirements, such as high-temperature heat or on-demand/constant supply, are either currently too expensive or still under development. In many cases, even basic industrial processes need to be redesigned for high rates of electrification, so **more R&D and especially demonstration is needed.**

Despite limited efforts to date, **targeted industry electrification solutions can quickly become major breakthroughs given the bulk of industrial energy use is for only a few energy-intensive commodities.** For example, **relocating energy-intensive industry to sites with low-cost, high load factor renewable electricity** has not yet been explored, but could be disruptive in the production chains of key chemicals and materials (e.g. ammonia, iron). **While cheap baseload renewables will be the main driver, there are also interesting opportunities to use renewable surpluses** for low-cost heating applications in industry (e.g. steam making). Sector-specific regulations in combination with technology-neutral fiscal incentives can kickstart commercialisation of emerging technologies.

A long-term perspective is going to be required for some specific sectors. Certain industries do not yet lend themselves to easy solutions. For example, for petrochemicals the future emergence of hydrogen and e-fuels from renewable electricity appears to be the only solution for primary production, apart from biomass feedstock. At this moment, the economics still pose a challenge. **Global considerations, such as international co-ordination, may potentially end up playing an important role in the smart electrification transition, to ensure a level playing field and avoid carbon leakage.**

Box 20. **Examples of smart industry electrification**

Sweden – In northern Sweden, the Swedish Energy Agency is co-financing a pilot initiative – Hybrit – along with companies SSAB, LKAB, and Vattenfall, with the aim of having an entirely fossil-free process for steel production by 2035. The initiative uses hydrogen from hydro and wind power, which will be fully competitive with traditional steel by that time (Hybrit, 2018). It has the potential to reduce Sweden's total CO_2 emissions by 10%, and Finland's by 7% if expanded. Beyond the government's active support for pilots and demonstrations, the initiative notes that a wide range of contributions from the state, research institutions and universities are required for success. These include good access to fossil-free electricity, improved infrastructure and the rapid expansion of high-voltage networks, other research initiatives, faster permitting processes and long-term support at the EU level.

7. ELECTRIFIED FUELS: UNDERSTAND THEIR LONG-TERM ROLES AND ECONOMICS

Using renewable electricity to produce **hydrogen or other synthetic fuels could potentially play a key role** in the electrification process, for example as a **complement to direct electrification** for hard-to-decarbonise areas, as a means of **flexibility and seasonal storage** for VRE integration, and as a possible **avenue to avoid stranding existing gas transport assets.** While most approaches around these ideas are technically feasible, a rapid scaling up is now needed to achieve the necessary cost reductions.

To initiate the scale-up required, **a clear policy framework is needed to provide clarity for infrastructure investment and improve the economics across the entire hydrogen supply chain** (equipment manufacturers, infrastructure operators, vehicle manufacturers, etc.) (IRENA, 2020g, 2019c). **Enabling access to stacked revenue streams** could prove important, through channels such as feed-in-tariffs for gas grid injection, energy service provision or carbon markets. **Policies aimed at final consumers** could also trigger hydrogen demand and justify investment in infrastructure, and could include emission restrictions (e.g. low-emissions zones, emission standards and targets), specific mandates for renewable energy content (e.g. certification or guarantee of origin schemes for hydrogen from renewables) and carbon pricing in targeted sectors.

Initial efforts could **focus on large-scale applications** (e.g. hundreds of megawatts to gigawatts) that **are able to rapidly generate economies of scale** with minimal infrastructure requirements, and in sectors where hydrogen from renewables stands out as the best performing option for meeting climate targets: large industry (refineries, chemicals facilities, methanol production) and heavy-duty transport (heavy trucks, trains on non-electrified lines, maritime). Securing long-term contractual arrangements with large downstream customers early on is likely to be critical to de-risk investment.

More broadly, **a key enabler for the scale-up and cost reduction of hydrogen technologies will be the availability of very low-cost renewable electricity, ideally at high load factors** (as found in the Middle East, North Africa, Mexico, Chile, Australia, the North Sea, etc.). Competition for the best renewable resources will be strong, but installation of hydrogen production facilities near such resources – where nodal electricity prices are also potentially lower – can improve the business case and ease grid constraints.

Box 21. **Examples of smart electrification of fuels**

Chile – In Chile, the government has set out a strategy and committed funding to support the production of hydrogen from low-cost solar power (Prudencio, 2019). Given the country's excellent solar resources, and cost reductions in solar PV technology, Chile has an opportunity to produce hydrogen at a competitive price by 2023. Funding has been provided to first establish a local technology consortium for the application of "green hydrogen" in large-scale industrial sectors and in mining transport fleets. As learning and production increase together over the longer term, the business case to supply international demand for hydrogen (e.g. in Japan) is expected to become positive.

5 CONCLUSION

This scoping report has laid out the basics of smart electrification with renewables in the transport, buildings and industrial sectors, highlighting the attractive synergies between both renewables and electrification across sectors. The report also outlines pathways to harness those synergies and deliver a future with higher-quality energy systems, improved health and quality of life, and reduced risk of potentially catastrophic climate change. Since delivering efficient pathways to electrification with renewables can be complex, this transition will require careful planning, political will and detailed national energy strategies and roadmaps. **While there is a growing body of knowledge to support the planning and implementation of such pathways, future research is also required to better understand uncertainties around the technical, economic and policy-related aspects of the transition.**

At a high level, **the key technical and economic questions that remain relate to the effects of electrification on energy system costs, and how wide the scope of cost-effective electrification actually is in various contexts.** For example, while a simple analysis would suggest that major electrification of transport and buildings could mean major investment in new peak power generation capacity, this report has shown that new forms of end-use flexibility due to electrification (e.g. smart charging, heat pumps paired with thermal storage) could potentially offset those needs. Efficiency improvements and optimisation of electricity consumption could also offset part of the new capacity requirements. If the scope of benefits is widened, a reduction in renewable curtailment could be seen as an offset to new investment costs. **The actual costs and benefits of these wider electrification aspects – for example, new investment vs. new options in end-use flexibility, efficiency or operation – need to be more comprehensively analysed and given equal attention as new capacity by policy makers.** This is particularly the case for new "smart" technologies or pilot business models, which may not yet be widely deployed, and it is not always clear exactly how much they can offset demand increases and at what cost.

Of course, a central element of electrification with renewables is to go beyond a focus on power systems only, and to also consider other sectors. For this reason, **even wider analyses need to be conducted that take into account the costs and benefits in other networks like gas or transport.** To do this, there needs to be a fuller understanding of the flexibility options in those sectors, as well as details on the costs of alternative supply options to electrification with renewables.

More studies that carry out such comprehensive – truly system-wide – analyses of electrification pathways, with better data on supply- and demand-side options, will allow answers to questions that are important to planners and policy makers, such as:

- In which sectors is electrification with renewables most valuable in the short, medium and long term, that is, where are the fewest substitution options now and in the future?
- Generally, where does electrification stop making sense?
  - » Would electric heat pumps or district heating systems work best in certain locations?
  - » What to do with industrial processes? Which ones can be electrified cost-effectively?
  - » Where do synthetic fuels derived from electricity begin to make sense? For which applications could they potentially be more effective than direct electrification in the long term?

It is critical to note that the answers to these types of questions will inevitably be heavily dependent on local and national conditions, for example the existence of pumped hydro storage, or interconnections with neighbours. For that reason, **case studies of particular national or local contexts – rather than relying on generic figures – are recommended to answer particular questions.**

While there is a need to conduct better-detailed and more comprehensive techno-economic studies of electrification, **there is also a need to address outstanding policy-related questions.** These include:

- What are the most effective system-wide policy frameworks to achieve the potential synergies between the deployment of renewable generation and electrification in buildings, transport and industry?
- How can policies integrate the economics of electrification as a whole, balancing costs and benefits to all sectors rather than specific options individually?
- Where and how can price signals be used to encourage electrification and renewable deployment?

In exploring the answers to these questions, it is important also to address two important underlying dimensions that are often ignored, but which are critical in the context of electrification – the behavioural and spatial dimensions.

There is still limited understanding of how end users will – or would like to – interact with the future energy system, and current operating models do not always reflect the needs of citizens or the potential role of active consumers. Governments and companies need to gather better insights into consumers' needs, expectations and willingness to adopt innovations, and should tailor solutions accordingly.

Spatial considerations in new investment should also be given more importance in the smart electrification transition, as they can materially change the cost-benefit analysis of new supplies (e.g. location-dependent solar and wind), demand centres (e.g. remote industrial sites, or district heating extensions), and the required scale of network infrastructure that will connect them (e.g. smart grid assets, or EV charging stations/networks) in ways that they have not previously.

In further exploring all of these issues related to the ideal technical, economic and policy evolutions of electrification with renewables, **lessons from successes and failures should continue to be widely shared, whether they relate to new technical demonstrations, pilot projects or enabling framework designs**.

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APPENDICES

I. HISTORICAL ELECTRIFICATION TRENDS ACROSS END-USE SECTORS

BUILDINGS

Figure 38 The level of electrification in the residential sector in selected countries during 1980-2018 (IEA, 2020a)

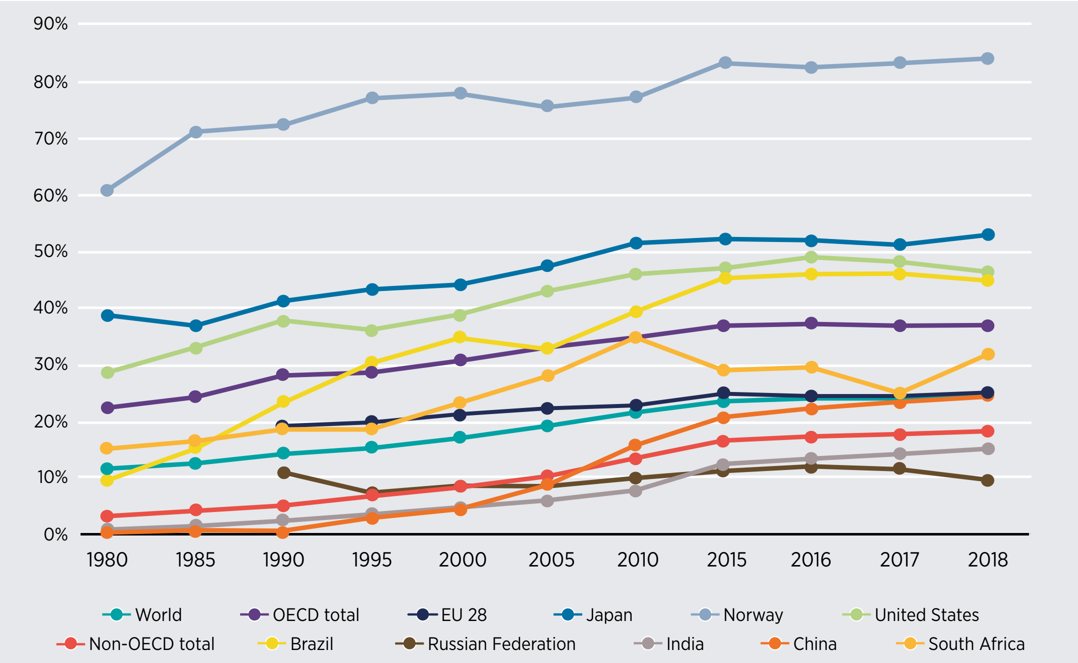
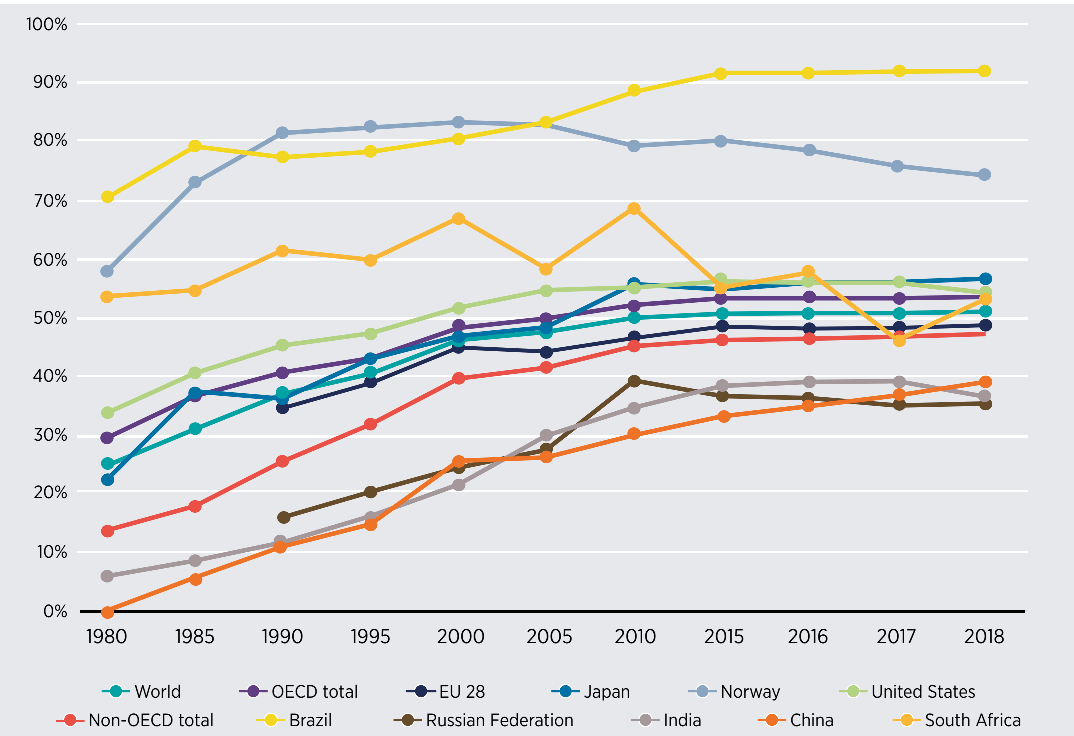
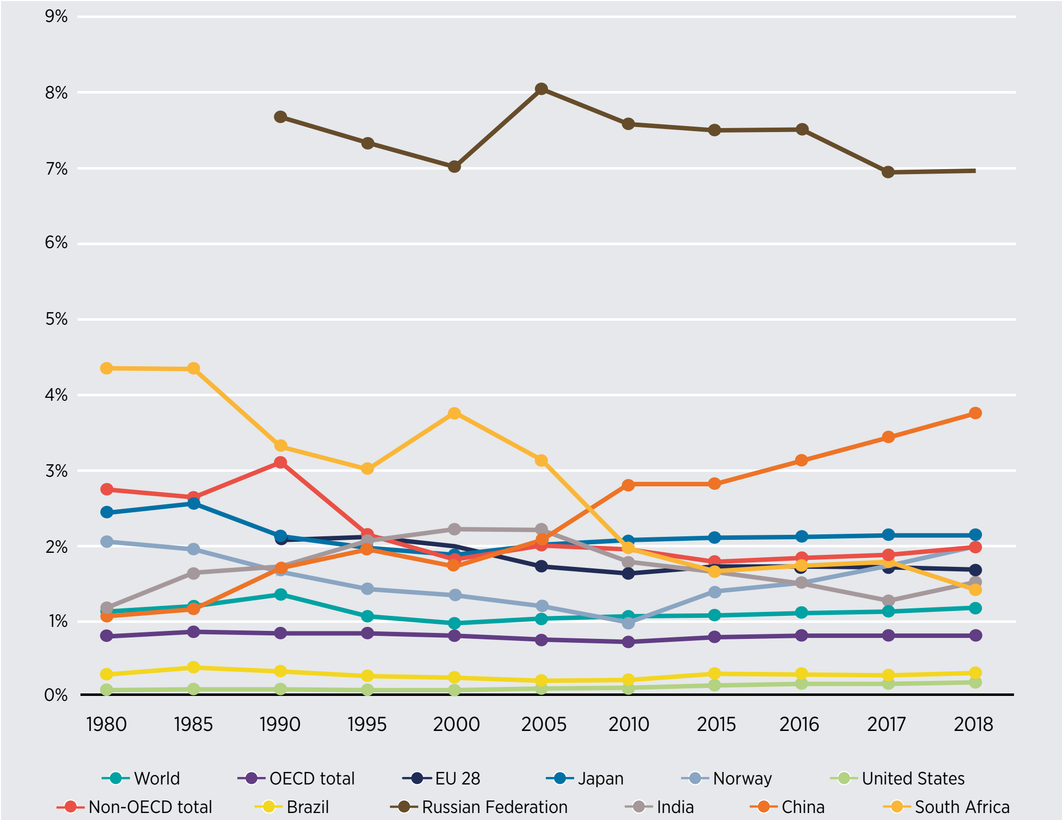


Figure 39 The level of electrification in the commercial and public services sector in selected countries during 1980-2018 (IEA, 2020a)



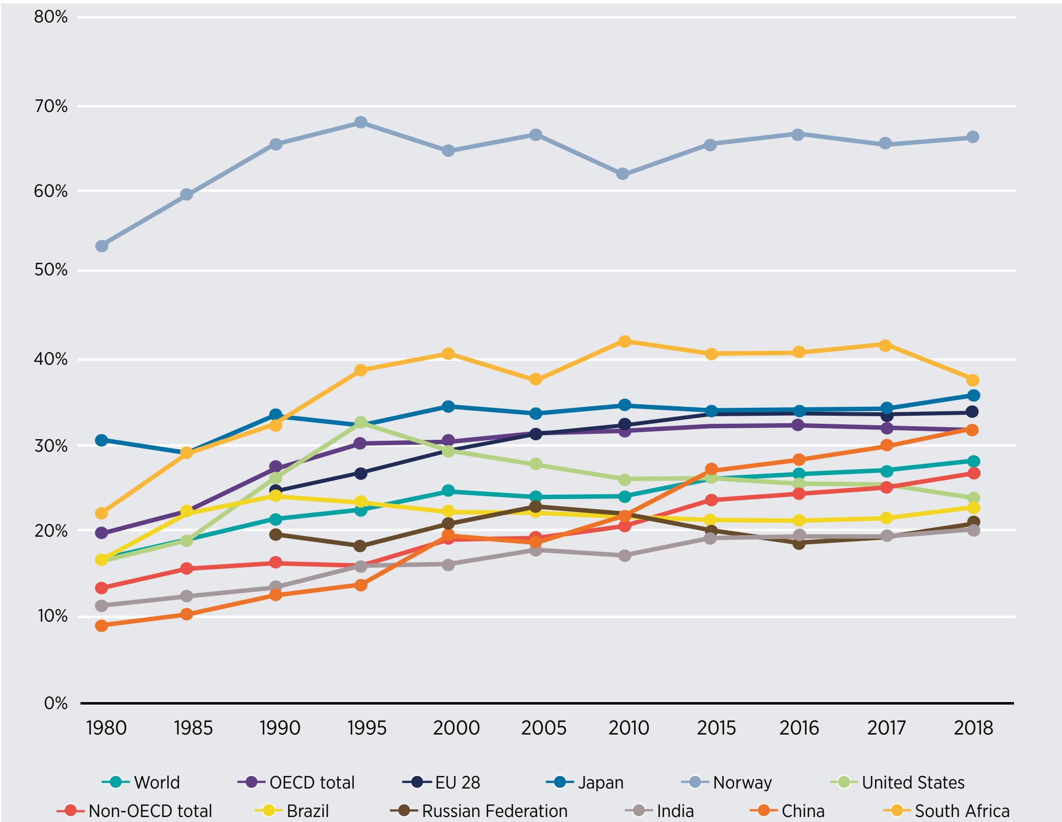
TRANSPORT

Figure 40 The level of electrification of transportation in selected countries during 1980-2018 (IEA, 2020a)



INDUSTRY

Figure 41 The level of electrification of industry in selected countries during 1980-2018 (IEA, 2020a)



II. COST PROJECTIONS FOR CERTAIN KEY E-FUELS

Table 7 Summary of cost projections for methane

Methane costs	Renewable electricity cost assumptions		CO_2 cost assumptions	Other assumptions	Year	Source
USD/GJ	USD/GJ	USD/MWh	(USD/tonne)			
5.6-16	3.1	11.2	342-350	95% reduction of capex from current level	2050	Blanco et al., 2018
16-20.3	0-7.8	0-28			NA	Gutiérrez-Martín and Rodríguez-Antón, 2016
28-36	7-23	25.2-82.8	34-202	Including transport costs	2050	Weltenergierat Deutschland, 2019
30	4.8	17.3	56	10 MWel plant, 6 100 hr/yr	2050	ENEA consulting, 2016
24-34	15-21.5	54-77	128-184	Power generation with excellent resource condition of the MENA region	2050	Siegemund et al., 2017
46-68	26.1	94	256-312	Including the methane storage costs	2050	Siegemund et al., 2017

Table 8 Summary of cost projections for synthetic diesel

Synthetic diesel costs		Renewable electricity cost assumptions		CO_2 cost assumptions	Year	Source
USD/GJ	USD/litre	USD/GJ	USD/MWh	(USD/tonne)		
26-50	0.94-1.8	5.8–15.6	21-56	NA	2050	Hauptmeier and Aldag, 2018
26.58	0.96	8.6	30.9	55	2030	Fasihi, Bogdanov and Breyer, 2016
38.5	1.4	15.6	56	NA	2050	Bazzanella and Ausfelder, 2017
49.8-56	1.8-2	NA	NA	NA	2050	ADEME, 2015
50-79	1.9-2.9	26.1	94	289-333	2050	Siegemund et al., 2017

Note: NA = not applicable

III. SMART CHARGING CASE STUDY SUMMARY

Table 9 Summary of case studies on impacts of EV charging and smart charging at the transmission network level

Region	Scenarios	Main findings	Key indicators addressed
Five selected states in the United States (California, Hawaii, Texas, New York, Minnesota) (RMI, 2016)	23% EV penetration in 2030, with i) uncontrolled charging, ii) optimised charging.	Peak loads would increase with high EV penetration, which would increase capacity investment, particularly at the distribution-feeder level. Controlled charging can help optimise grid resources, and avoid investment in new peak generation capacity.	**Peak demand** **California:** Increase of 11.1% in uncontrolled charging scenario vs 1.3% in optimised charging scenario. **Hawaii:** Increase of 9% in uncontrolled charging scenario vs 1.3% in optimised charging scenario. **Texas:** Increase of 4.9% in uncontrolled charging scenario vs 0.9% in optimised charging scenario. **New York:** Increase of 3.4% in uncontrolled charging scenario vs 0.6% in optimised charging scenario. **Minnesota:** Increase of 3.1% in uncontrolled charging scenario vs 0.5% in optimised charging scenario.
Overall New England, United States system (six states) (VEIC and NASEO, 2013)	25% PHEV penetration in 2030, with i) evening concentrated charging; ii) evening distributed charging; iii) increased work charging access; iv) off peak charging.	Peak load increase would require significant investment in grid and generation capacities. Spreading the load over evening hours could cut the peak load increase, and charging only at off-peak hours could avoid any increase at all.	**Peak demand** Increase of 19% in evening concentrated charging scenario, vs 6% in evening distributed charging scenario, and 0% in an off-peak charging scenario. **Annual average demand** Increase of 3%.
Germany (Schucht, 2017)	25% household penetration rate in 2035 (10 million EVs), with i) worst case: basic home charging during peak load; ii) best case: smart charging shifts demand to match PV production; 100% EV fleet electrification in 2050, with i) worst case: basic home and work charging; ii) smart charging shifts demand to match PV production.	Electricity consumption of EVs is low compared to total energyconsumption (<3%) in 2035; EVs also have very limited impact on peak demand, especially with smart charging in place and when looked at in combination with flexibility of heat pumps.	**Peak demand** Increase of 8% in worst-case scenario in 2035; vs no significant increase with home and work charging by 2050, and minor decrease of winter peak in best-case optimised charging scenario.
Four countries (Sweden, Norway, Denmark, Germany) (Taljegard, 2017)	100% EV penetration in 2050, with i) inclusion of ERS for freight transport; ii) inclusion of ERS and advanced smart charging with V2G.	EV charging correlates with the electricity system peak load and thereby increases the need for peak power capacity and CO_2 emissions. If advanced smart charging is applied, passenger EVs can smooth the net load curve so that the peak net load is actually reduced.	**Peak demand** Increase of 20% in ERS scenario, vs -7% in ERS and advanced smart charging scenario.
United Kingdom (National Grid, 2017)	100% penetration, with up to 25m EVs on British roads by 2050, i) with smart charging; ii) without smart charging.	As EVs grow in number, their peak electricity demand could offer the most challenges, which should be met with better use of smart technology, engaged consumers and use of vehicles with a lower energy demand.	**Peak demand** Increase of 30% (18 GW) in no smart charging scenario, vs 10% (6 GW) in smart charging scenario.

Notes: ERS = electric road systems; PHEV = plug-in hybrid electric vehicle.

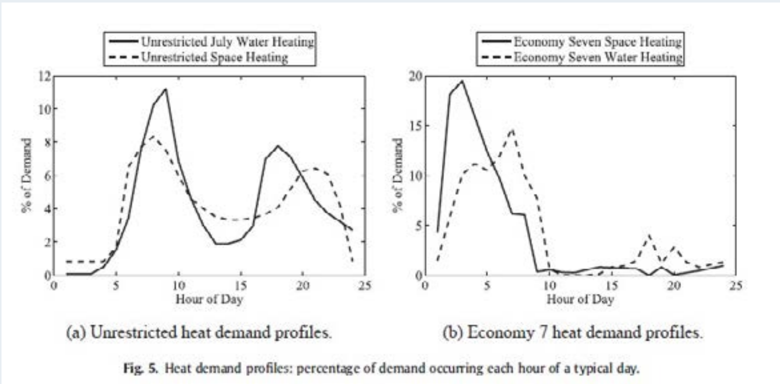
Table 10 Summary of case studies on impacts of EV charging and smart charging at the distribution network level

Region	Scenarios	Main findings	Key indicators addressed
A typical feeder circuit with 150 homes in Midwestern United States (Engel et al., 2018)	25% EV penetration, with i) flat tariff; ii) time-of-use tariff.	EVs will likely reshape the electricity load curve, and the most pronounced effect will be an increase in evening peak loads, which will lead to challenges at a local level due to the varied regional spread of EVs. With time-of-use tariff guiding EVs smart charging, the increase in feeder circuit peak load is decreased by 14%.	**Peak demand** Increase of 30% in flat tariff scenario, vs 16% in time-of-use tariff scenario.
A residential neighbourhood of 19 houses in Toronto (Awadallah, Venkatesh and Singh, 2016)	Simulated with chargers between 1.4 kW and 20 kW i) Worst case scenario: all EVs are simultaneously charging during peak winter and summer loads with 100% EV penetration (one EV per household); ii) typical spring weekday: with EV penetration of 33%, 66%, and 100%.	With charger size less than 3.3 kW, no overload of transformer occurs at any level of EV penetration. Chargers with a rating of 6.6 kW cause moderate overload for system components even at low levels, whereas large chargers with 10 kW rating and higher require a system upgrade before they can be accommodated.	**Transformer overload** Overload of 64% in uncoordinated charging scenario with 100% EV penetration and 6.6 kW chargers, vs no overload in any charging scenario with 3.3 kW chargers.
A residential distribution grid (Ahourai et al., 2013)	i) 0-50% penetration rate of EVs; ii) 50% penetration rate with coordinated EV charging.	An increase in EV usage beyond 20% poses problems such as overloading the existing infrastructure, especially for the transformer, the life time of which reduces significantly due to long overloading time.	**Transformer overload** Overload of 60% in uncoordinated charging scenario, vs no overload in co-ordinated charging scenario.
A suburban area of 228 households in Germany (Schucht, 2017)	Two scenarios: i) worst case: simultaneous charging during peak load; ii) best case: charging optimisation throughout the night.	EVs together with heat pumps might lead to congestion in low-voltage grids and increase in peak demand if a smart charging strategy is not applied.	**EV penetration limits** In a worst-case scenario, limited EV penetration (due to transformer capacity limits) is as low as 2% (5 EVs) without optimisation; in a best-case scenario with optimised transformer and charging, EV penetration is 400% (4 EVs per household).
A residential distribution grid in Norway (Lillebo, 2018)	Assessing EV hosting capacity at 0-100% penetration.	Injecting reactive power at the location of a fast charger significantly reduces voltage deviation.	**EV penetration limits** EV hosting capacity is 100% for the majority of end users, but considering the limitations of all end users on the system at once, the distribution grid could tolerate 50% EV penetration in terms of voltage, and between 10% to 20% EV penetration if limited by the weakest cable's rated power. **Transformer overload** Overloaded hours of 5.8% in 100% EV penetration scenario.

Turkey (Saygın et al., 2019)	"High Growth" market scenario foresees 2.5 million passenger EVs in Turkey by 2030, representing 10% of the vehicle stock, with 1 million charging points.	Scenario has little impact on grid operation because the system has sufficient idle capacity. Integrating 2.5 million EVs increases the current low-level capacity factors of medium- and low-voltage transformers, which would reduce distribution grid tariffs. Grid investments aligned with demand growth, optimally placed charging points, smart charging, and time-varying tariffs to incentivise EV charging at off-peak hours are required to achieve the above scenario. Achieving EV penetration above 10% of the vehicle stock in 2030 would require additional investments, efficiency improvements in transport, and a reduced share of private car use among mobility options.	**EV penetration limits** Turkey's distribution grid could integrate about 2.5 million EVs with nearly no new investments and limited impact on distribution grid operation (in terms of maximum loading increment and voltage violations). This represents about 10% of the vehicle stock anticipated in 2030.

IV. SMART HEATING CASE STUDY SUMMARY

Table 11 Summary of case studies on the impacts of heating electrification and smart heating on power systems

Study	Main findings
United Kingdom (Quiggin and Buswell, 2016)	The United Kingdom's space heating profile for the buildings sector is characterised with two sharp peaks, one at around 8 a.m. and the other at around 7 p.m. The UK Economy 7 tariff programme encourages shifting of heat consumption by 7 hours to night using storage devices. Economy 7 would not decrease the peak demand compared with the uncontrolled case, but the minimum demand would be higher, narrowing the difference between minimum demand and peak demand by 15%. **Figure 42** Demand profiles of building heat demand in UK. Source: (Quiggin and Buswell, 2016) 
Belgium (Baeten, Rogiers and Helsen, 2017)	A case study of the Belgian electricity system in 2030 investigates the large-scale introduction of actively controlled heat pumps (50 000 units) with a demand response programme and hot water storage tanks. It shows that demand response decreases the uncontrolled winter peak demand of 15 GW by 9%, and by an additional 4% with storage tanks. Implementing a demand response programme was substantially cheaper than building a power plant of equivalent size.
Europe (Paardekooper et al., 2018)	Results from the Heat Roadmap Europe project, which investigated the deep decarbonisation of the heating and cooling sector in Europe, showed that district heating systems could supply the half of Europe's heat demand under their decarbonisation strategy by 2050. District heating systems would supply urban heat demand using industrial excess heat (25% of the heat supply), large-scale heat pumps (up to 30%), and CHP (up to 35%), while the strategy is supplemented with the refurbishment of old buildings, and installation of heat pumps to meet rural heat demand. This strategy would cost-effectively cut carbon emissions from the energy sector by 89% compared to 2015 levels. A lower share for district heating systems may disproportionally increase the costs of the electricity grid. Thermal storage systems for district heating would cover on average 2-8 hours in larger cities and 6-48 hours in smaller cities. Thermal storage for district heating is more flexible than heat pumps installed in individual buildings.

V. SYSTEMIC ECONOMIC ASSESSMENT CASE STUDY SUMMARY

A number of studies have explored the investment needs for direct electrification of end-use sectors, with varying degrees of smart electrification strategies implemented. A selection of such studies is summarised below, with key points on the extent to which direct electrification of different sectors is sensible given its impacts on power system infrastructure.

To explore how more systemic perspectives could affect the extent and composition of electrification in different sectors, the table below gathers studies which perform cross-sectoral economic assessments of infrastructure requirements for widespread electrification. As not all studies address the same elements of the overall infrastructure landscape, a legend - corresponding to Figure 18 at the start of Section 2.4 – denotes their coverage.

SECTORAL ASSESSMENTS

Study area	Coverage	Findings
France (Artelys et al., 2016)	Renewable generation · Electricity T&D · Buildings H_2 production · Gas T&D · Transport H_2 derivate production · Chemical T&D · Industry	This study explores the infrastructure required for a 100% renewable electricity mix in France by 2050 with modest increases in current electricity shares (to 28% in industry, 33% in transport and 52% in buildings). It finds that due to efficiency measures, overall electricity consumption could in fact decrease by 2050, to 422 TWh from 442 TWh in 2013. It finds transmission network capacity should be increased by 36% compared to current levels, however, and cross-border interconnection capacity must also increase. Taking into account the distribution network resulted in a low impact both on the optimal mix and on the associated overall cost. Hydrogen and/or e-fuel infrastructure was not modelled comprehensively, only for its flexibility potential (no need at 80% renewables penetration, but 17 GW of power-to-gas for inter-seasonal storage at 100%).
Netherlands (Moraga and Mulder, 2018)	Renewable generation · Electricity T&D · Buildings H_2 production · Gas T&D · Transport H_2 derivate production · Chemical T&D · Industry	This study presents the implications of three electrification scenarios for road transport and domestic heating and cooking in the Netherlands to 2050, including a “reference”, “intermediate”, and “full” electrification scenario. It finds that full electrification of the domestic buildings sector would increase demand by 35 TWh vs the reference case in 2050, or 30% of current total electricity consumption. For transport, the full electrification scenario explores rates of 88% electrification of all cars, 87% for vans, 16% for trucks, and 84% for buses. The total electricity necessary to power these shares by 2050 is 40 TWh (mainly from cars at 30 TWh). Renewable generation of roughly 40% total supply (216 TWh) is explored by 2050 in the full electrification scenario, and is found to require no seasonal storage needs for excess supply, as import reductions are sufficient to absorb renewable generation at that share. In terms of electricity network, the study finds that capacity for the full electrification scenario would be roughly 50% larger than existing in 2016.

Netherlands (ECN and Alliander 2017)	Renewable generation / Electricity T&D / Buildings H_2 production / Gas T&D / Transport H_2 derivate production / Chemical T&D / Industry	This study explores the need for flexibility in the Netherlands energy system with strong growth in electrification through EVs, heat pumps, and other electrified end-uses by 2050. At various regional levels, incidence of overloaded assets due to increasing adoption of PV, EV and heat pumps could affect 8% of distribution transformers and 9% of substation transformers by 2030, and 35% and 45% respectively by 2050. While this can be ameliorated with work and investment on the grid and smart solutions on behalf of the grid operator, it was also found that most overloads are expected to occur in city centres, and more quickly. In Amsterdam, for example, the Dutch energy network company Alliander warns peak times could increase by a factor of 2.5-6 (Kerstens, 2019). The old age of networks and building stock in such cities could call into question the potential for extensive installation of modern electric technologies and smart solutions required for total heating electrification, for example. Hydrogen and/or e-fuel infrastructure was not modelled comprehensively, but only for its flexibility potential.
United Kingdom (Quiggin and Buswell, 2016)	Renewable generation / Electricity T&D / Buildings H_2 production / Gas T&D / Transport H_2 derivate production / Chemical T&D / Industry	This study assesses six published UK scenarios for 2050 with electrified heat and transport using a detailed hourly data to see if the electricity demand is met at all hours of the year, with all but two scenarios assuming heat pumps meeting more than 75% of heat demand. The assessment showed that all scenarios except one demonstrated supply issues on winter days with high heat demand, even if flexibility options such as DSM, battery storage, V2G, among others, are fully utilised. The scenario that contained a significant portion of CHP generation was the only one without problems. Hydrogen and/or e-fuel infrastructure was not modelled comprehensively, but only for its flexibility potential.
United Kingdom (Delta Energy & Environment and Energy Networks Association, 2012)	Renewable generation / Electricity T&D / Buildings H_2 production / Gas T&D / Transport H_2 derivate production / Chemical T&D / Industry	This study for the UK's residential heating sector for 2050 compares two strategies, one with heat pumps and district heating systems (to which heat pump supplies 50%) and the other with additional renewable-based fuel (biomethane) injected into the gas networks. The comparison shows that the former option would add peak capacity of 48GW, while the latter would require 24 GW of additional peak capacity. Corresponding distribution investment needs also would halve in the latter case. The study shows that the use of heat pumps, either decentralised or centralised, may require substantial investment in to cover seasonal electricity demand peaks.
Europe (Bazzanella and Ausfelder, 2017)	Renewable generation / Electricity T&D / Buildings H_2 production / Gas T&D / Transport H_2 derivate production / Chemical T&D / Industry	This study covers deep decarbonisation strategies for the chemical sector in Europe. It shows that while electrification could substantially reduce CO_2 emissions by 2050, meeting the expanded power demand for chemical production alone would require 40% more carbon-free electricity than the amount projected for the whole energy sector under the IEA's 2°C scenario.

Europe (Lechtenböhmer et al., 2016).	Renewable generation · Electricity T&D · Buildings H_2 production · Gas T&D · Transport H_2 derivate production · Chemical T&D · Industry	This study on energy-intensive basic material sectors (steel, cement, etc.) in Europe suggests that a complete shift to electricity in those sectors would result in demand of 1600 TWh, larger than the entire current industrial energy demand in Europe (1000 TWh).
Europe (Kasten et al, 2016)	Renewable generation · Electricity T&D · Buildings H_2 production · Gas T&D · Transport H_2 derivate production · Chemical T&D · Industry	Looking at electrification of the passenger car stock in the European Union by 2050, this study finds that 80% penetration of EVs would require an additional 170 GW of renewable generation capacity (for perspective, that would be 75% of EU renewables capacity in 2010, and a 22% increase in expected renewables capacity by 2050).
United Kingdom (Burke and Rooney, 2018)	Renewable generation · Electricity T&D · Buildings H_2 production · Gas T&D · Transport H_2 derivate production · Chemical T&D · Industry	This study explores a case in which hydrogen fully replaces natural gas by 2050 in the United Kingdom. This would require a minimum of 6 GW per year of new hydrogen capacity starting in 2030. In comparison, both onshore and offshore wind have together grown at an average rate of 1.8 GW per year during 2010-2017. The scenario therefore implies that hydrogen capacity would need to grow roughly 3 times faster than the wind sector in the United Kingdom, and do so consistently for 20 years.
European Union (Paardekooper et al., 2018)	Renewable generation · Electricity T&D · Buildings H_2 production · Gas T&D · Transport H_2 derivate production · Chemical T&D · Industry	This study presents results from the Heat Roadmap Europe project, which investigated the deep decarbonisation of the heating and cooling sector in Europe. The study highlights a critical role for district heating systems in particular, which supply half of heat demand under their decarbonisation strategy towards 2050. District heating systems supply urban heat demand using industrial excess heat (25% of the heat supply), large scale heat pumps (up to 30%) and CHP (up to 35%). The strategy is supplemented with refurbishment of old buildings and use of heat pumps to supply rural heat demand. A lower share of district heating system may disproportionally increase the costs of the electricity grid. Thermal storage systems for district heating would cover on average 2-8 hours in larger cities, and 6-48 hours in smaller cities. Thermal storage for district heating is found to provide more flexibility over an approach that only considers installation of heat pumps in individual buildings. More detailed discussion of this study can be found in Box 11.

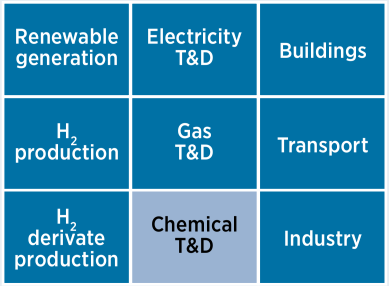
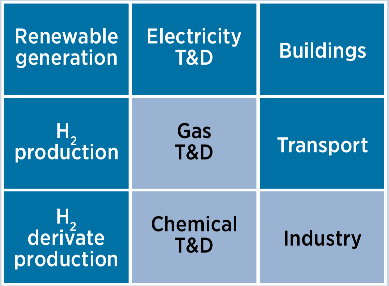
Study area	Coverage	Findings
National		
Germany (Hansen et al., 2019)	Renewable generation; Electricity T&D; Buildings; H_2 production; Gas T&D; Transport; H_2 derivate production; Chemical T&D; Industry	This study explores the infrastructure required for 100% renewable energy in Germany by 2050. In the heating sector, the composition of supply in 2050 includes 30% district heating (an expansion from 16% in the reference case) and a majority usage of individual heat pumps for the remainder of supply. Key measures to reach 100% renewable heat without overreliance on biomass include solar thermal production (20 TWh/yr addition across individual and district heating installations), heat pumps (particularly in district heating where capacity would be increased by a factor 10 to a total of 7 GW) and excess industrial heat (13 TWh/yr addition). For industry, heating under 100°C (25% of industrial heat demand) is met by an equal amount of district heating and heat pumps. In the electrification scenario, the remaining 50% of industrial fuel consumption is assumed to be electrified. Additional electrification increases power demand by 133 TWh/yr, which also requires electrical grid reinforcements. In transport, 85% vehicle electrification would increase power demand by 118 TWh/yr. For the remaining 15%, a hydrogen-based approach would entail annual hydrogen demand of 143 TWh/yr, which entails an increase in power demand of 194 TWh/yr. This implies total electrolysis capacity of 45 GW with one-week hydrogen storage of 7 500 GWh (at a cost of EUR 54 billion for all hydrogen infrastructure). Alternatively, a full-electrification approach (e.g. for all heavy-duty transport, ships and aircraft) would create an additional 143 TWh/yr of electricity demand. Overall, all of the 100% renewable scenarios see efficiencies in primary energy demand, e.g. 50% lower vs the reference case in 2050, but electricity production increases in all scenarios from roughly 580 TWh/yr in the 2050 reference scenario to between 1 100 TWh/yr and 1 300 TWh/yr.
Germany (Hansen, 2017)	Renewable generation; Electricity T&D; Buildings; H_2 production; Gas T&D; Transport; H_2 derivate production; Chemical T&D; Industry	This study presents a range of results from an analysis of decarbonisation scenarios for the German energy system by 2050. With a large shift to renewable electricity in an 85% emissions reduction scenario, it finds that primary energy demand would decline by 43% to around 2 000 TWh by 2050 from 2013 levels, as the overall efficiency of the system (i.e. useful energy/primary energy) increases from less than 40% to over 60%. In that overall demand, e-mobility makes up about 200 TWh, heat pump and electric heat demand about 150 TWh, electrolysis for hydrogen production about 100 TWh, and synthetic methane production roughly 50 TWh. An additional 5% reduction in emissions to 90% decarbonisation would see large increases in electrolysis and synthetic methane demand, both to roughly 175 TWh. In heating, the composition of demand is roughly 55% electric heat pumps (30/25% air/ground composition), 20% district heating, and 20% gas heat pumps. Heat storage also increases significantly to roughly 11.5 TWh (6.5 TWh central district heating, and 5 TWh decentralised). In terms of indirect electrification, electrolysis capacity is seen to increase to roughly 70 GW, methanisation capacity to 30 GW, and power-to-liquid roughly 5 GW.

Germany (Ruhnau et al., 2019)	Renewable generation / Electricity T&D / Buildings H_2 production / Gas T&D / Transport H_2 derivate production / Chemical T&D / Industry	This study looks specifically at the composition of direct vs indirect electrification across heat (both for buildings and industry) and road transport end-use sectors in Germany, in a review of results from 22 decarbonisation scenarios for 2050. Electricity demand does not cover non-heat applications in the industry and buildings sectors, which was 399 TWh in 2015. In scenarios that meet emission reduction targets greater than 80%, electricity (both direct and indirect) for heat generation is between 269 TWh and 517 TWh with the inclusion of heat for industrial processes, and between 63 TWh and 199 TWh without. The electricity (both direct and indirect) for road transport ranges from 71 TWh to 281 TWh, with the exception of one study that reaches 545 TWh. Electrification is sensitive to GHG mitigation targets in the studies, but more so for transport than in buildings, where alternatives to heat decarbonisation exist like building retrofits or direct renewable use through bioenergy or solar thermal. If heating for industry is included, there is a greater connection between GHG mitigation and heat electrification, since electricity-based solutions play an important role in decarbonisation of industrial process. In terms of direct vs indirect electrification, in scenarios with emission reduction targets greater than 80%, direct electrification covers 39-84% of heat for buildings and 35-88% of heat in industry. Indirect electrification meets 22% of building energy demand and 35% of industrial demand. Indirect electrification has more significant shares in scenarios with GHG emission reduction targets greater than 85%, where it contributes to long-term energy storage. In buildings, heat pumps deliver 27-75% of electrification depending on the scenario, and electric furnaces see a maximum of 12%. For industrial heat, heat pumps are only significant in one scenario, and electric furnaces more commonly meet heat demand. For car transport, direct electrification meets 19-66% of demand in scenarios with 80% emissions reduction targets, and 38-95% in scenarios with 85% emissions reduction targets. Indirect electrification meets 0-46% across all scenarios. For trucks, while emissions reduction scenarios beyond 85% all feature at least 51% electrification, other results vary widely given that truck transport is assumed to be decarbonised by non-electric renewables and efficiency, or is considered a major remaining emitter as a hard-to-decarbonise sector. In five of the scenarios that do feature direct electrification of trucks, overhead lines play a role. In terms of indirect electrification for transport, hydrogen is a significant contributor in seven out of ten scenarios where more than 20% of total car transport is supplied by synthetic fuels. Across all types of transport, synthetic liquids are only considered in scenarios with over 85% decarbonisation.
International		
Germany and the Netherlands (Gasunie and TenneT, 2019)	Renewable generation / Electricity T&D / Buildings H_2 production / Gas T&D / Transport H_2 derivate production / Chemical T&D / Industry	A joint study by Gasunie and TenneT, the gas and electricity TSOs of Germany and the Netherlands, describes the integrated energy infrastructure required in these two countries to reach a 95% emissions reduction by 2050. Scenarios were based on whether the decarbonisation transition was primarily steered by local councils, national governments, or international trading agreements. The local scenario involves the highest degrees of electrification, the national scenario sees a focus on wind and power-to-hydrogen, and the international scenario involves producing hydrogen in the best renewable energy sites and shipping it to demand centres. The local and national scenarios see electricity demand increase by 30% in the Netherlands, while all scenarios for Germany see electricity volumes only change by 10%. In both countries, the volumes of gas (hydrogen or methane) to be transported are the same or higher than today's volumes. The study found that electricity, heat and gas could be integrated to absorb the fluctuations of VRE. Giving guidance on the optimal location of power-to-gas installations can reduce the long-term need for infrastructure expansion. The study finds that Dutch gas infrastructure would transport hydrogen, biomethane, and natural gas, while Germany's would transport hydrogen, biomethane, and domestic and imported synthetic methane. In the study's modelling, power-to-gas is a cornerstone of the future energy system, and all scenarios show existing electricity and gas infrastructure could play a complementary role. For example, coupling electricity and gas systems allowed VRE generation access to existing underground gas storage facilities.

Germany and Japan (Jensterle, 2019)	Renewable generation; Electricity T&D; Buildings H_2 production; Gas T&D; Transport H_2 derivate production; Chemical T&D; Industry	A joint German-Japanese study was conducted on the role of clean hydrogen in future energy systems. In the study, the drivers of hydrogen development in Germany are ambitious emission reductions, a need for grid stability, seasonal storage and sector coupling. In Japan the drivers are moderate emission reductions, energy security and technology exports. The vast majority of hydrogen in Japan is projected to be used in electricity generation, while in Germany it is used in transport, industry and synthetic fuels production. In 2050 Germany's demand for hydrogen is 300-600 PJ per year, representing up to 15% of total final energy demand. In Japan, it is 600-1 800 PJ per year, representing up to 22% of total energy demand. Hydrogen supply is mainly domestic green hydrogen and imported synthetic fuels in Germany and mainly imported blue and green hydrogen in Japan. In final energy demand, Germany will likely have more synthetic fuels than hydrogen, while Japan has only one scenario that considers synthetic methane. The study considers countries with the best conditions for green hydrogen production in terms of cost per kWh to be China, Argentina, Niger, Australia and the United States, while the best conditions in terms of growth-adjusted emission reductions in 2030 are Iceland, Malta, Estonia, Switzerland and Norway.
Northern Europe (Ikäheimo et al., 2018)	Renewable generation; Electricity T&D; Buildings H_2 production; Gas T&D; Transport H_2 derivate production; Chemical T&D; Industry	This study on Northern European integrated power-to-ammonia into a cost-optimisation model for a 100% renewable power and heat system in 2050. The researchers found that wind dominated the power mix throughout the countries included and that the majority of ammonia was produced by Norway and consumed by Germany. In comparing various scenarios, they found that increasing the maximum electricity transmission capacity between Germany and Norway causes a 27% decrease in Norwegian production of ammonia as it is cheaper to transfer energy as electricity using HVDC lines. However, constraints on transmission make importing ammonia an important method of regional balancing. It was estimated that ammonia pipelines are only cost-efficient when their capacity is several hundred megawatts. The study also found that 70% of district heating would be provided electrically by heat pumps and the rest by biomass CHP, as both hydrogen and ammonia were found to be too expensive to use towards heating. The model accounted for the transport sector by integrating EVs, which contribute to storage mainly on a daily basis. Power-to-ammonia was found to serve three roles: ammonia is used as a feedstock by the fertiliser industry, as energy storage and as a substitute for power transmission. These two latter roles contribute to power system flexibility. The study found that renewable ammonia can be produced at a price similar to today's price; it becomes more competitive when natural gas prices increase, as the latter is the main feedstock in conventional ammonia production.
European Union (European Commission, 2019, 2018a, 2018b)	Renewable generation; Electricity T&D; Buildings H_2 production; Gas T&D; Transport H_2 derivate production; Chemical T&D; Industry	The European Commission's METIS project is a series of studies based on a model that simulates the European energy system, including electricity, gas and heat, on an hourly basis over a year. A study within this series discusses the role of Power-to-X (P2X) in decarbonising the transport, buildings and industrial sectors. It evaluates whether P2X competes with other low-carbon alternatives like biofuels and biomethane by running the METIS model under different conditions of CAPEX evolution, power generation and electricity prices. Model results indicate that the profitability of P2X largely depends on low electricity prices. Countries with high shares of VRE, such as Spain, exhibit over 2 000 hours of near-zero electricity prices. Countries with high shares of variable renewable energy, like Spain, exhibit over 2 000 hours of near zero electricity prices. In these cases, water electrolysis needed for power-to-hydrogen is competitive compared to hydrogen production using steam methane reformation with carbon capture and storage. Power-to-hydrogen is less capital intensive than power-to-methane or power-to-liquid, which also involve costlier decarbonisation when the final energy carriers are combusted. A separate study integrated decarbonisation options for district heating, including the use of biomass, geothermal, solar heating, heat pumps, and CHP, into the METIS model. Another METIS study jointly analyses how various flexibility measures, like those presented in previous METIS studies, can be combined most effectively. It presents an optimal portfolio of flexibility solutions to allow the grid to be 80% based on renewable energy. Model results indicate that cross-border transmission of 164 GW in 2030 is the main source of flexibility for the EU power system, especially on a weekly basis. Storage is the second most important flexibility option, while demand side management and P2X are also important. 200 GW of gas-fired power is required as dispatchable backup peak units.

European Union (ASSET project) (De Vita et al., 2018)	Renewable generation / Electricity T&D / Buildings H_2 production / Gas T&D / Transport H_2 derivate production / Chemical T&D / Industry	This study presents the advantages of sector coupling and co-ordination for the use of hydrogen in addition to renewable energy in decarbonising the European Union by 2050. The report presents three stylised scenarios to integrate hydrogen into decarbonisation strategies: as an energy carrier and as a combustion fuel to be used directly by industry; as a feedstock for producing synthetic fuel; and as a power storage tool. The report discusses the pros and cons of each scenario, arguing for a balanced strategy that integrates all possible roles of hydrogen in the most promising sectors. The balanced approach is compared to a previously developed basic decarbonisation scenario that does not involve hydrogen, and instead aims only at energy efficiency, high shares of renewables, electrification, and the use of biofuels. The approach that harnesses hydrogen in a balanced way primarily involves mixing hydrogen and bio-methane into the gas distribution system to be used for heating and heavy transport, using hydrogen directly for combustion in the steel, iron and chemical industries, and using Power-to-Hydrogen for power storage. The latter point requires 29% of total power generation in 2050 to be devoted to hydrogen production. This leads to a marginal drop in average EU electricity prices compared to the basic decarbonisation scenario, due to the role of hydrogen storage in smoothing load curves and eliminating the need for curtailment. The balanced strategy leads to renewables increasing by 36% compared to the basic decarbonisation scenario in 2050. The balanced strategy also leads to a 96% reduction in carbon emissions from the energy and industrial sectors in 2050, which is 12 percentage points higher than in the basic decarbonisation scenario. The cost of abatement in the balanced scenario is EUR 88/tCO_2, while it is almost double that level at EUR 182/tCO_2 in the basic decarbonisation scenario. This reduction in costs is primarily due to the technologies, especially in the transport sector, that allow multiple roles for hydrogen as a means of sectoral integration.
European Union (Wind Europe, 2018)	Renewable generation / Electricity T&D / Buildings H_2 production / Gas T&D / Transport H_2 derivate production / Chemical T&D / Industry	This study compares two scenarios for the decarbonisation of Europe: one that involves accelerating and perfectly implementing current policies; and one that is more ambitious and is compatible with the aim of limiting the global temperature increase to 2°C. Highlighting the second scenario, the study indicates that it is technically and economically possible to increase the share of electricity in the energy mix from 24% to 62% by 2050, with 78% of the share being renewable. The Paris-compatible scenario involves a 90% emissions reduction by 2050, compared to only 74% in the less ambitious scenario. In addition, it would cost only 0.5 percentage points more than the less ambitious scenario, at 2.7% of Europe's annual GDP to 2050. The Paris-compatible scenario's broader electrification programme would decrease the total demand for energy by 33% with savings in industry at 30%, in buildings at 18%, and in transport at 46%. This scenario involves an 86% share of electricity in industrial processes by 2050. Commercial buildings reach an electrification level of 78%, while household buildings reach a level of 59% by 2050. In transport, 95% of new car sales are electric by 2035, while rail transport is 90% electric by 2030. EVs are able to contribute sufficient short-term storage, even if only 10% of EV battery capacity is made available to the grid. Hydrogen is used in transport, for heating in buildings and industry, and for the seasonal storage of electricity. Hydrogen is important in these applications, but accounts for only 4.8% of total energy demand in 2050. The researchers found that, in the Paris-compatible scenario, wind would account for 36% of power generation by 2050. The expansion of the European power grid is a requirement for any decarbonisation pathway, with 12 000 GW-km/yr of new power lines required by 2050.

European Union (Connolly, Lund and Mathiesen, 2016)	Renewable generation / Electricity T&D / Buildings H_2 production / Gas T&D / Transport H_2 derivate production / Chemical T&D / Industry	This study uses the EnergyPLAN model to present a Smart Energy Europe scenario for 100% renewable energy in 2050. The transition towards this scenario is analysed using steps organised in order of scientific and political certainty. First, nuclear plants are decommissioned, then heat savings are implemented, private transport is electrified, heat pumps are established for rural areas, then district heating for urban areas, heavy transport is converted to renewable fuels, coal and oil are replaced with natural gas and biomass, and finally methane replaces natural gas. Distribution infrastructure is mainly only considered in the context of district heating and gas grids. The results of the study show that the European grid can be 100% renewable without requiring an unsustainable amount of bioenergy. This is possible because flexibility from connecting the power, heating, cooling, and transport sectors allows for an 80% VRE share. This scenario costs 10-15% more than the reference scenario, but creates 10 million additional jobs due to investment in local generation and fuel production rather than fuel imports. The scenario in 2050 has no fossil fuel use or energy imports into Europe, and almost no carbon emissions. Each step in the scenario is compared to the business-as-usual scenario in terms of primary energy supply, carbon emissions, and cost. For example, electrifying personal transport leads to a 17% lower primary energy supply, 16% fewer emissions, and 1% higher costs compared to the business-as-usual scenario. Deploying district heating and heat pumps in urban and rural areas respectively leads to a 28% lower primary energy supply, 32% fewer emissions, and similar costs to the business-as-usual scenario, assuming all preceding steps listed above are already completed.
European Union (Blanco et al., 2018)	Renewable generation / Electricity T&D / Buildings H_2 production / Gas T&D / Transport H_2 derivate production / Chemical T&D / Industry	This study uses cost optimisation to measure the potential of power-to-methane (P2M) in the European Union's transition to a low-carbon system by 2050. P2M both provides flexibility to the power system and helps decarbonise other sectors, while being able to use existing gas transmission infrastructure. The model includes residential and commercial buildings, transport, industry and agriculture. It includes various storage options like hydrogen and power-to-heat to compare against P2M as a technology and includes a simplified representation of the power grid in order to assess the trade-off between curtailment and expanding transmission to distant load centres. The gas network is represented as having three main components: cross-border trading, transmission, and distribution. More than half the scenarios run saw P2M capacity reach above 40 GW, which represents 8% of gas demand. The maximum capacity reached among scenarios is 546 GW, representing 75% of gas demand. In these particular scenarios, electricity consumption for electrolysis can account for up to 40% of generation. System-level drivers are found to have more influence on P2M potential compared to technology drivers. The two system drivers that most favour P2M are a low potential for carbon dioxide storage and a penetration of VRE above 60%. The study highlights that direct subsidies for P2M technology are more effective than taxing natural gas.
European Union (Blanco Reano et al., 2019)	Renewable generation / Electricity T&D / Buildings H_2 production / Gas T&D / Transport H_2 derivate production / Chemical T&D / Industry	This study models the EU energy system to 2050 to assess the potential role of hydrogen. In scenarios that include other flexible technologies such as biomass, nuclear, demand response and grid expansion, hydrogen production flows increase sevenfold compared to today's levels. Hydrogen use is present in most scenarios for heavy transport and industry and as a feedstock even when hydrogen prices are high (i.e. above EUR 7/kg). For the buildings sector, heat pumps are prioritised, while hydrogen and power-to-methane (P2M) are unattractive except for specific types of buildings that cannot easily be renovated. The power sector benefits from seasonal storage using hydrogen. In the heavy transport sector, moderate emissions reduction targets involve liquefied methane being dominant as a bridge fuel, but high targets above 95% decarbonisation lead to a switch towards the use of hydrogen, electricity or biofuels. The main factors found to improve the economic performance of hydrogen and P2M were system-wide: more stringent carbon emission targets, the absence of carbon storage and a low biomass potential. Annual costs for the deployment of hydrogen in the European Union across all sectors, especially transport, would be EUR 40-140 billion per year. For reference, the cost of fossil fuel imports into the European Union in 2018 was EUR 325 billion. A scenario with high electrolysis capacity (around 1 TW) found that the cashflow from electrolysers to power producers enables 70-90% of countries to recover their capital investment in wind and solar. In addition, electrolysers become price setters in the power market for 2 000 to 6 000 hours per year and contribute to the balancing of power supply and demand.

European Union (Evangelopoulou et al., 2019)		Using various scenarios in an enhanced version of the PRIMES energy system model, this study compares the three roles of hydrogen as a fuel, as a feedstock for hydrocarbons, and as a storage carrier, in a carbon-neutral European Union in 2050. They find that hydrogen enables sectoral integration of energy supply and demand by playing these roles. By assessing the potential roles of hydrogen through scenarios with varying technological assumptions, the paper defines a balanced scenario that highlights sectors where hydrogen is most likely to provide advantages. The balanced scenario foresees a 15% by volume share of hydrogen in the gas distribution network, where it is mixed with biomethane and synthetic methane. It also foresees the direct use of hydrogen in heavy transport, its direct combustion in industry like iron, steel and glass production, its use as a feedstock for ammonia and chemicals, the use of fuel cells in co-generation for heating, and the use of hydrogen for electricity storage. In the balanced scenario, final energy consumption decreases by 31% compared to 2015 levels. Electricity represents 47% and hydrogen represents 12% of final energy consumption. In this scenario, 63% of hydrogen is used as a feedstock, mainly for synthetic fuels. Compared to a purely electrification-based scenario, the balanced scenario requires about 1.4 times more electricity generation to enable the production of hydrogen and synthetic fuels. Finally, total power generation in the balanced scenario is 84.9% from renewable energy, 9.6% from nuclear and 5.5% from gas. All scenarios have similar annual costs and similar electricity prices (EUR 156-160/MWh), which are in line with projected electricity prices for 2021-2030. The paper concludes by noting that, under current uncertainties, policy makers should promote the long-term visibility of all decarbonisation technologies so that investors can fund large-scale projects to enable learning-by-doing.
Global (Ram et al., 2019)		This study presents a global 100% renewable energy model for 2050 that incorporates the power, heat, transport, and desalination sectors. The full industrial sector including cement, iron, steel, chemicals, metals, and pulp and paper will be included in a future iteration of this study. The model expects the global population to reach 9.7 billion and final energy demand to grow by 1.8% every year. The model includes regional pricing for synthetic fuels, hydrogen, and methane production. With hourly resolution, their model foresees electricity generation increasing four or five-fold from 2015 levels, while accounting for more than 90% of primary energy demand in 2050. Solar PV accounts for 69% of the total energy supply with wind at 15%. The levelised cost of energy for the resulting system is slightly cheaper than the existing energy system, reducing from EUR 54 to EUR 53/MWh. Meanwhile the levelised cost of electricity decreases from EUR 78 to 53/MWh and the levelised cost of heat increases from EUR 39 to 40/MWh. Given the shift to renewables, levelised costs become dominated by capital expenditure as fuel costs become negligible. At a regional level, energy system costs decrease by 31% in the Middle East and North Africa, by 22% in North America, by 34% in South America, and by 15% in Europe. Energy storage, primarily batteries, will meet 23% of electricity demand. It will also meet 26% of heat demand, primarily through thermal energy storage. Desalination is expected to account for 4% of total primary energy demand in 2050. In the transport sector, 30% of final energy demand is met by renewably produced liquid fuels and 25% is met by hydrogen. Installed storage capacity for gas, mainly hydrogen, is 150 TWh by 2050.

VI. GLOBAL AND REGIONAL SCENARIO COMPARISON

GLOBAL SCENARIO COMPARISON

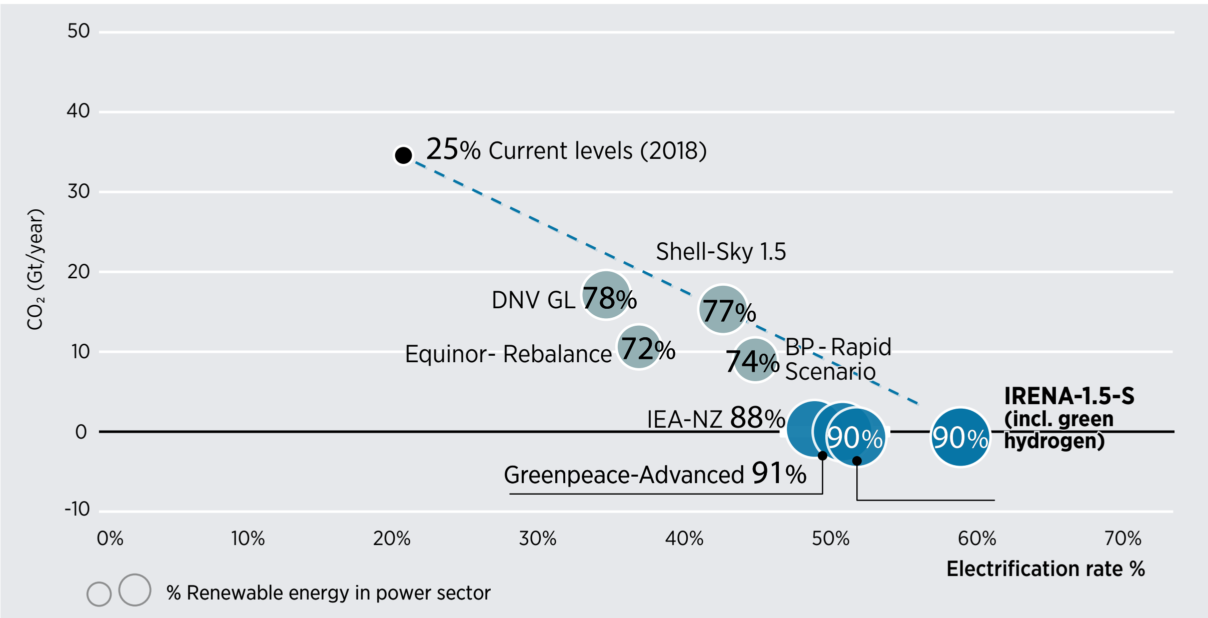
In addition to IRENA's *World Energy Transition Outlook*, a number of other global energy scenarios have recently been published to explore transition pathways for the energy system in the coming decades.

Figure 31 shows the wide range of results from these studies in terms of the degree of electrification and the depth of long-term decarbonisation realised by the scenarios considered. Even when the scenarios are consistent with the Paris Agreement targets according to the scenario authors, they show different visions of the future. This is not surprising, as it reflects the complexity and uncertainties in the energy transition and the different approaches and assumptions regarding the development of renewable energy, as well as the different combinations of electrification, emissions reductions strategies and overall carbon budgets.

Two below-2°C scenarios, DNV GL and Equinor, predict a rapid transformation of the global energy sector. Though they reach similar electrification shares (35% for DNV GL and 37% for Equinor) by 2050, they have different global-energy-related CO_2 emissions, 17 Gt/yr for DNV GL and 10.6 Gt/yr for Equinor by 2050. Among those scenarios claiming compatibility with the Paris Agreement target of staying under a 2°C temperature rise, the electrification share in 2050 varies substantially as well, from 45% in BP's "Rapid" Scenario to 52% in the Greenpeace "Advanced" Scenario.

There is, however, a broad consensus on the central role that renewables would play in electricity generation, with percentages ranging from 72% in Equinor's "Rebalance" Scenario to 90% in IRENA's 1.5°C Scenario. Despite the differences between the energy scenarios, there is also a clear consensus on the important role that electrification powered by renewable energy sources has in the decarbonisation of the energy system. With a share of 51% for direct electrification and 58% if green hydrogen and its derivates are included, coupled with 90% renewables in the power sector in 2050, IRENA's 1.5°C Scenario shows a higher electrification rate than the other scenarios.

Figure 43 CO_2 emissions versus electrification rates in various energy scenarios.



Notes: dark blue = 1.5°C scenarios; grey blue = below 2°C scenarios. The size of the bubbles in the figure and the number indicated beside the scenario description reflect the share. 1.5-S = 1.5°C Scenario.

Sources: Shell's 2021 "Sky 1.5" Scenario (Shell, 2021); BP's "Rapid" Scenario (BP, 2020); the "Below 1.5°C" and "Above 1.5°C" Scenario from the Intergovernmental Panel on Climate Change (IPCC, 2018); Greenpeace's 2015 "Advanced" Scenario (Greenpeace, 2015); Equinor's "Rebalance" Scenario (Equinor, 2020); DNV GL's Energy Transition Outlook 2020 (DNV GL, 2020) and IEA's Net Zero by 2050 (IEA, 2021b).

Similarly, the range of scenarios underpinning the IPCC Special Report on Global Warming of 1.5°C show a wide range of possible electrification shares (Box 22).

The next sections briefly discuss some of the assumptions and details of certain scenarios to explain why they arrive at different electrification shares (both overall and in the various sectors), while a high-level comparison of scenario details can be seen in Table 12 and Table 13.

Box 22. **Electrification in scenarios underpinning the IPCC Special Report on Global Warming of 1.5°C**

Figure 44 shows the range of 2050 electrification outcomes across the ensemble of 85 pathways underpinning the IPCC's 2018 *Special Report on Global Warming of 1.5°C*. Despite all being consistent with a 1.5°C future pathway, the share of electricity in final energy consumption in the ensemble ranges from a minimum of 33.7% to a maximum of 71.1%. Such a wide range of electrification rates and overall emissions in scenarios consistent with an average temperature increase of 1.5°C reflects the wide range of assumptions underpinning these scenarios and their sensitivity to these assumptions such as those in terms of CCS deployment and land use.

Figure 44 Share of electricity in final energy consumption (%) vs global energy-related CO_2 emissions in 2050 (Gt/yr) in pathways underpinning the Special Report on Global Warming of 1.5°C by the Intergovernmental Panel on Climate Change (IPCC) 2018.

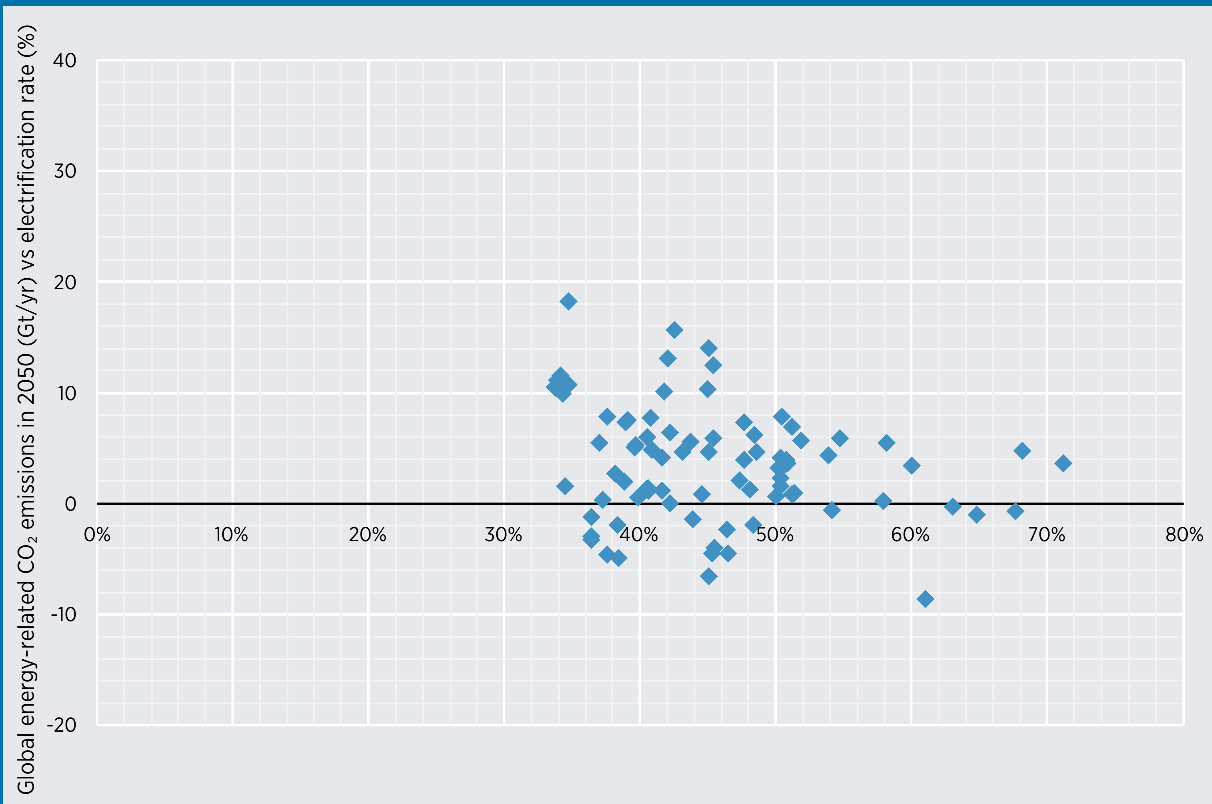


Table 12 Electricity shares in global scenarios by 2050

Scenario	Region	Final energy consumption	Buildings	Industry	Transport	Renewables share in power sector
DNV GL Energy Transition Outlook 2020	Global	41%	52%	41%	27%	78%
Equinor "Rebalance" Scenario	Global	42%	61%	45%	37%	72%
Greenpeace "Advanced" Energy [R]evolution Scenario	Global	52%	52%	44%	52%	92%
IEA Net Zero by 2050	Global	49%	66%	46%	44%	88%
IRENA Transforming Energy Scenario	Global	49%	68%	42%	43%	86%
IRENA 1.5°C Scenario	Global	51%	73%	35%	49%	90%
Shell "Sky 1.5" Scenario	Global	44%	80%	50%	17%	74%

Table 13 Assumptions in global scenarios

	Industry			Building			Transport		Others
Scenario	**P2G deployed**	**Direct electrification deployed**	**Heat pump deployed**	**P2G deployed**	**Direct electrification deployed**	**Heat pump deployed**	**P2G deployed**	**EV deployed**	**CCS**
DNV GL Energy Transition Outlook 2020	yes	yes	yes	yes	yes	yes	yes	yes	yes
Equinor "Rebalance" Scenario	no	yes	no	no	yes	yes	no	yes	yes
Greenpeace "Advanced" Energy [R] evolution Scenario	yes	yes	yes	yes	yes	yes	yes	yes	no
IEA Net Zero by 2050	yes	yes	yes	yes	yes	yes	yes	yes	yes
IRENA Transforming Energy Scenario	yes	yes	yes	yes	yes	yes	yes	yes	yes
IRENA 1.5°C Scenario	yes	yes	yes	yes	yes	yes	yes	yes	yes
Shell "Sky 1.5" Scenario	yes	yes	yes	yes	yes	yes	yes	yes	yes

BP "Rapid" Scenario

In its Energy Outlook 2020, BP considers three scenarios that explore different pathways for 2050: Rapid, Net Zero and Business-as-Usual. The Rapid scenario assumes that new policy measures are put in place to accelerate the decarbonisation of the different sectors of the economy, led by a significant increase in carbon prices.

In the Rapid Scenario, the progressive decarbonisation of the energy system leads to an increasing electrification of final energy use, reaching 45% of total final consumption by 2050, with most of the growth in electricity demand driven by emerging countries in Asia and Africa. There is particularly strong growth of electricity use in the transport sector, as increasing amounts of road transport are electrified. By 2050, EVs account for 80-85% of the stock of passenger cars, and for 70-90% of light- and medium-duty trucks. In both the industrial and buildings sectors the increasing use of electricity replaces the falling demand for oil, gas and coal.

DNV GL Energy Transition Outlook Scenario

In the fourth edition of its Annual Outlook, DNV GL presents its "best-estimate" forecast of the energy future. This single model, for the period through to 2050, assumes the establishment of new policy measures and includes behavioural changes related to the changing environment.

In this model, DNV GL foresees a growing dominance of electricity in final energy demand, reaching 41% of the world's final energy use in 2050 with an annual average growth in electrification of 2.4% per year. As total energy demand reduces, electricity is thus projected to gradually replace coal, oil and, later, gas in final energy demand. The majority of the electricity demand, which will more than double over the next 30 years, will come from the buildings and industrial sectors, while the fastest growth will be in the transport sector. Electricity demand in transport multiplies by 26 by 2050. The model foresees a rapid uptake of EVs (passenger EVs first and then commercial EVs): they will account for half of the passenger vehicles sold worldwide by 2032, and for the vast majority of all vehicles in 2050.

Equinor "Rebalance" Scenario

Equinor constructs three scenarios to embrace a wide range of possible future outcomes: Reform, Rivalry and Rebalance. Rebalance is a "well-below 2°C" scenario that challenges the assumption that the world can reach its climate and sustainability goals without significant consequences for economic growth and global income distribution. "Rebalance" shows a development path where economic growth accelerates in the emerging regions and slows in industrialised regions, which shift focus from maximising GDP growth to optimising other indicators on human development and well-being.

In the Rebalance Scenario, electrification is key, reaching 42% of total final energy consumption by 2050. The transport sector would see a massive shift to electricity, with EVs accounting for nearly all light-duty vehicles sales by 2040-2050, at the same time as a modal shift toward public transport reduces growth in the global car fleet. Electrification is also a key driver in decarbonising buildings and industry, sectors which reflect shares of electricity close to the IRENA Transforming Energy Scenario.

Greenpeace "Advanced" Energy [R]evolution Scenario

In its 2015 Sustainable World Energy Outlook, Greenpeace presented two global energy transition scenarios, the "Basic" and the "Advanced" Energy [R]evolution Scenarios. The Advanced Energy [R]evolution Scenario represents a pathway towards a fully decarbonised energy system by 2050.

Electrification is key in the Advanced Scenario, reaching 52% of total final energy consumption by 2050. In the heating sector, the scenario foresees a strong role for geothermal (including heat pumps), hydrogen and renewable electricity (including in the industrial sector). A substitution of the remaining gas consumption by green hydrogen is also foreseen. In the transport sector, electricity would account for 52% of consumption by 2030. Hydrogen and other synthetic fuels generated using renewable electricity can assist to increase the renewable share in the transport sector. In 2050, 14 EJ of renewable-based hydrogen is foreseen to be used in the transport sector.

IEA Net Zero by 2050 Scenario

The Net Zero Emissions by 2050 Scenario reflects an integrated approach to achieving net-zero emissions by 2050.

Electricity plays a central role in this scenario, reaching 50% of the global final energy consumption in 2050. The final consumption of electricity more than doubles due to an increase in electricity use in end-use sectors and for hydrogen production. The buildings sector realises the highest level of electricity share in energy consumption (66%), followed by road transport (60%) and industry (45%). The scenario foresees that there will be 2 billion EVs, hybrid and FCEVs in 2050, and more than 40% of households will use electricity for space heating.

Shell "Sky" Scenario

Sky sees electrification as one of the most important energy system trends. Under the Sky scenario the amount of electricity as an energy carrier would grow very quickly across the economy, reaching 44% of total final energy consumption in 2050. Compared to historical electrification trends, the growth rate of the electricity share would triple in the coming decades to reach the level envisioned in this scenario by 2050.

The Sky Scenario sees the buildings sector having the highest share of electrification by 2050 (80%), followed by industry (50%) and transport (17%).[17] In the buildings sector, Sky foresees greater energy efficiency combined with the rapid electrification of the building stock. In the industrial sector, Sky foresees two drivers of evolution: improvements in energy efficiency for industrial processes, and the substitution of hydrogen, biomass and electricity for natural gas and some coal use in light industry processes. In the transport sector, the transformation occurs very rapidly. As early as 2030, more than half of the cars sold globally would be electric, with all new passenger cars being electric by 2050.

IRENA's key takeaway from the scenarios

While all of these studies and analyses arrive at different specific numbers for key measures like the degree of electrification in various sectors by 2030 or 2050, there is remarkable consistency in their overall conclusions - namely that an energy transition based on electrification, greater efficiency and renewable generation is both technologically possible and economically affordable. The collective weight of the studies, therefore, supports and reinforces IRENA's own analysis of the feasibility of the smart electrification with renewables pathway.

17 *IRENA estimations based on published dataset for the Sky Scenario. Available from: https://www.shell.com/energy-and-innovation/the-energy-future/scenarios/shell-scenario-sky.html*

ELECTRIFICATION PROSPECTS IN SELECTED MARKETS

United States

As shown in Appendix I, throughout the second half of the 20th century, the use of electricity in the energy system of the United States has grown steadily, from about 300 TWh in 1950 (3% of final energy consumption) to almost 4 000 TWh in 2016 (19% of total final energy consumption).

Studies of long-term electrification in the United States

IRENA has analysed the long-term potential for electrification of the United States' energy system in the context of a global decarbonisation scenario compatible with the Paris Agreement. Under such a scenario, electricity represents 52% of total final energy consumption in the country by 2050.

Two other studies have made comprehensive investigations into the prospects for electrification of the US energy system: NREL (Mai et al., 2018; Murphy et al., 2021) and EPRI (EPRI, 2018). They are shown in Table 14 and Table 15 alongside IRENA's Transforming Energy Scenario for 2050. Both studies see the transport sector as the largest opportunity for efficient electrification, due both to its significant dependence on direct fuel use today and the availability of cost-competitive electro-technologies. However, both studies also identify very significant opportunities in the buildings and industrial sectors.

Table 14 Electricity shares in scenarios for the United States

Scenario	Region	Final energy consumption	Buildings	Industry	Transport	Renewable share in power sector
IRENA Transforming Energy Scenario 2050	United States	52%	79%	24%	59%	83%
NREL High Scenario	United States	41%	68%	27%	29%	23-75%
EPRI Transformation Scenario	United States	47%	63%	48%	29%	39%

Table 15 Assumptions in scenarios for the United States

	Industry			Building			Transport		Others
Scenario	P2G deployed	Direct electrification deployed	Heat pump deployed	P2G deployed	Direct electrification deployed	Heat pump deployed	P2G deployed	EV deployed	CCS
IRENA Transforming Energy Scenario 2050	yes	yes	yes	yes	yes	yes	yes	yes	yes
NREL High Scenario	no	yes	yes	no	yes	yes	no	yes	yes
EPRI Transformation Scenario	no	yes	yes	no	yes	yes	no	yes	yes

NREL

NREL considers electrification in all on-road transport, most of the buildings sector and parts of the industrial sector together accounting for three-quarters of total US primary energy and for which there are "market ready or near market-ready" technologies available. The study develops three scenarios of future adoption of end-use electric technologies up to 2050:

1. Reference: serves as a baseline of comparison to the other scenarios and has the least incremental change in electrification through 2050.
2. Medium: describes a future with widespread electrification among the "low-hanging fruit" opportunities in EVs, heat pumps and certain industrial applications, but without considering a transformational change.
3. High: describes a transformational change in electrification, such as that which could be achieved through a combination of technology advancements, policy support and consumer enthusiasm for electro-technologies.

NREL concludes that there is significant potential for widespread adoption of end-use electric technologies in the United States. By 2050, the share of electricity in final energy consumption could reach 41% under the most ambitious electrification assumptions, compared to 23% under reference conditions.

The transport sector experiences the greatest electrification. In the High scenario, the penetration of plug-in vehicles in the light-duty fleet would reach nearly 84% by 2050, up from 11% in the Reference scenario.

In the buildings and industrial sectors, NREL sees less potential for transformational change, but the increase in the degree of electrification is also very substantial. In the buildings sector,[18] electric devices provide up to 61% of space heating, 52% of water heating and 94% of cooking services by 2050 in the High Scenario (compared to 17%, 26% and 34% respectively in the Reference Scenario). NREL sees also potential for adoption of electrotechnologies in the industrial sector. In the High Scenario, 63% of curing needs, 32% of drying services, 56% of other process heating and a range of other industrial end uses could be electrified by 2050. It is important to note that these ranges do not reflect upper bounds, but rather customer adoption results and expert judgment consistent with the study's scope and goals.

More recently, NREL also explored the potential interactions between end-use electrification and the evolution of electricity supply, considering the same major themes that are described in this report (Murphy et al. 2021). In their scenarios that included significant penetrations of renewable energy (~75%), NREL found similar synergies in terms of electrification leading to a more conducive environment for integrating VRE. In particular, they found that the changing load shapes associated with electrification (including both the timing and flexibility of electrified loads) could enable the more efficient integration of VRE technologies by reducing the rate at which VRE generation is curtailed.

18 Including both the commercial and residential sectors.

EPRI

EPRI considers four scenarios for future electrification in the United States: Conservative, Reference, Progressive and Transformation. The first two focus on how changes in technology costs and performance affect outcomes. The last two explore the impact of potential economy-wide carbon policy.[19]

The role of electricity as an energy carrier grows very substantially in all four scenarios. Electricity's share in final consumption could increase to 47% in the Transformation Scenario versus 32% in the Conservative Scenario by 2050.

The transport sector presents the largest opportunity for electrification according to EPRI and drives electrification growth in all four scenarios through the expansion of EVs which are set to become more cost-effective than their conventional alternatives, markedly in the light-duty segment, but also for heavy transport.

In the buildings sector, heat pump technology is a key driver for efficient electrification. In the Reference Scenario, the percentage of building surface primarily heated with heat pumps grows from 15% today to 50% by 2050. In the Transformation Scenario, the carbon policies assumed cause an even stronger shift towards heat pump technology.

In the industrial sector, EPRI's Reference Scenario projections show limited shift towards electricity. In the Transformation Scenario, carbon incentives improve the economics of electrification for industry.

Europe

As shown in Appendix I, electricity consumption has grown by almost 30% over the last 25 years in the European Union, while final energy consumption has increased by just 2% over the same period. As a result, the degree of electrification grew from 17% in 1990 to almost 22% today, substantially above the world average.

Studies of long-term electrification in Europe

IRENA has analysed the potential for electrification of the European Union's energy system by 2030 and 2050. By 2030, electricity could represent 27% of total final energy consumption, up from 24% expected with the continuation of current policies. This would require generation of 230 TWh/yr additional power, an amount comparable to Spain's electricity demand today (IRENA, 2018c). By 2050 IRENA's Transforming Energy Scenario results in a European electrification rate of 49%. This would require a very significant acceleration of the rate of electrification compared to past trends across all end-use sectors.

Eurelectric

Other organisations have published studies considering high degrees of electrification of energy uses in the European Union. In May 2018, Euroelectric[20] released a report exploring three decarbonisation scenarios to cut emissions by 80%, 90% and 95% below 1990 levels between now and 2050 (Eurelectric, 2018). The first scenario considers an acceleration of current technological trends; the second scenario considers a shift in policies to significantly remove barriers and promote decarbonisation and electrification; and the third, most ambitious, decarbonisation scenario considers early technological breakthroughs and deployment of electrification options at scale through global coordination.

19 Conservative: considers a slower decline in the relative cost of a key technology for electrification: EVs; Reference: technology costs and performance improve over time; Progressive: technology costs and performance improve over time and a moderate carbon price is being applied (USD 15/tCO_2); Transformation: technology costs and performance improve over time and a stringent carbon price is being applied (USD 50/tCO_2)

20 Eurelectric is the sector association which represents the common interests of the electricity industry at pan-European level, plus its affiliates and associates on several other continents.

Under the most ambitious scenario, the study concludes that a European economy where 60% of final energy consumption is directly provided by decarbonised electricity can be achieved by 2050. An overview of this scenario is as shown in Tables 16 and 17 with the IRENA Transforming Energy Scenario shown for context. The deepest electrification levels are realised in the transport and buildings sectors, both reaching a 63% share of electricity in final energy consumption. However, the study also identifies significant potential for electrification of processes in industry, where the share of electricity could reach 50% by 2050.

An alternative to the electrification of end uses is to produce synthetic clean fuels from renewable electricity. Some recent scenarios see a role for these technologies in Europe in the future, however there is a wide range of results in terms of potential. For instance, the German Energy Agency (DENA) projects 533-908 TWh of such fuels in Germany by 2050 (dena, 2018), which would equal 29-45% of the primary energy supply needs of the country, whereas other studies see a much smaller potential of about 234 TWh for the European Union as a whole (Ecofys, 2018).

Table 16 Electricity shares in scenarios for Europe

Scenario	Region	Final energy consumption	Buildings	Industry	Transport	Renewables share in power sector
IRENA Transforming Energy Scenario 2050	European region	49%	55%	54%	32%	86%
Eurelectric High Scenario	European region	60%	63%	63%	50%	NA

Table 17 Assumptions in scenarios for Europe

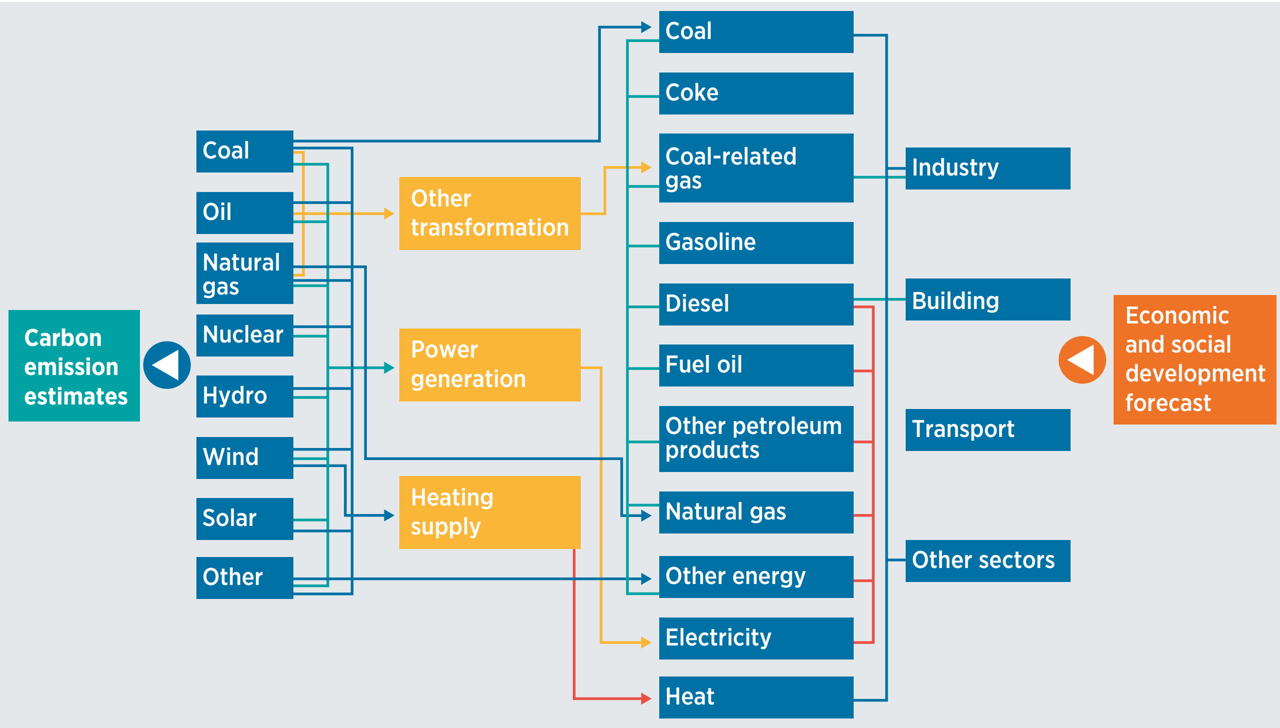
	Industry			Building			Transport		Others
Scenario	P2G deployed	Direct electrification deployed	Heat pump deployed	P2G deployed	Direct electrification deployed	Heat pump deployed	P2G deployed	EV deployed	CCS
IRENA Transforming Energy Scenario 2050	yes	yes	yes	yes	yes	yes	yes	yes	yes
Eurelectric High Scenario	yes	yes	yes	unknown	yes	yes	yes	yes	yes

VII. CHINA SCENARIO STUDY DETAIL

METHODOLOGY

To help plan China's long-term energy and power development, the State Grid Energy Research Institute constructed an integrated economy-energy-environment analysis model based on the Unified Global Energy Research Platform. The model includes forecasts of economic development and end use energy demand, simulations of power system planning, and estimates of primary energy demand and carbon emissions.

Figure 45 Integrated model: China's economy – energy - environment



Each module of the overall model includes its own model. The economic and social development prediction module, for example, is based on a simultaneous equation model that estimates growth in gross domestic product and in various industries. End use energy demand predictions come from the Long-range Energy Alternatives Planning model (LEAP), which looks at four main sectors: the **industrial** sector, the **buildings** sector, the **transport** sector and **others**, which include agricultural and construction industries. Power system planning uses a multi-regional source-grid-load-storage planning model, which looks at the electric power source, cross-regional power transmission channels, demand response and and energy storage in order to optimise overall system operation and to test planning strategies.

To estimate primary energy demand, the primary energy needed for electricity generation is removed from the electrical plan results. Then, the remaining primary energy demand is estimated based on the predicted end use energy demand, considering the conversion losses of heating, coal washing, coking, and oil refining. Carbon dioxide emissions from burning energy are estimated based on the average fossil fuel emission factor.

SCENARIO SETTINGS OF CHINA'S CASE

This report examines the new trends of high-quality economic growth and the transition to cleaner energy sources, and constructs future scenarios of development in China that involve greater electrification and use of clean energy.

This report outlines two scenarios: a Reference Scenario and an Electrification Scenario.

In the Reference Scenario, the use of conventional energy-using technology gradually slows while electrification steadily increases. Meanwhile, the consumption of natural gas rapidly increases, the consumption of coal declines, and petroleum use remains relatively stable. Steady improvements can be seen in the efficiency of the end uses of energy. The development of new energy sources can be seen maturing, the regulation of the electricity system is enhanced, and the coordinated development of the resource-grid-load-storage paradigm gradually takes shape.

In the Electrification Scenario, the use of conventional energy-using technology also gradually slows. But the uptake of electric technologies such as electric boilers, electric kilns, heat pumps, smart homes and EVs is much quicker than in the Reference case. As a result, electricity rapidly becomes a substitute for coal and oil in end uses. In addition, electrification promotes a more rapid improvement of end use energy efficiency. Under electrification, natural gas consumption maintains steady and rapid growth, but at a slower pace than in the Reference Scenario. In the Electrification Scenario, new energy sources rapidly develop and the grid becomes more intelligent, leading to greater co-ordinated development of the resource-grid-load-storage paradigm than under the Reference case.

The two scenarios share the same economic and social development boundary conditions. In addition, energy service demands under the two scenarios are determined by the same economic and social development levels. The difference in end use energy demand is mainly the result of the greater energy efficiency of electrified end use technologies compared to those powered by fossil fuels.

For more details of the two scenarios please see Table 18 below.

Table 18 Typical factors in scenario settings

	Reference Scenario	Electrification Scenario
Economic environment	The international and the domestic social and economic environment remain stable, economic growth gradually slows, the economic structure is optimised and adjusted, and growth momentum shifts from the traditional manufacturing sector to the tertiary industry and high end manufacturing industry. The GDP growth rate is expected to be 5.5% and 5.0% during the 14th and 15th Five Year Plans. The GDP growth rate is expected to decrease to 4.2% in 2030-2040 and 3.2% in 2040-2050. Slow population growth is expected with a gradual decrease causing an expected population of 1.4 billion in 2050.*	
Electrification	Electrification gradually increases in all fields. For example, the proportion of electric furnace steel in the steel industry is expected to reach 10% in 2020, 24% in 2035, and 32% in 2050. The number of EVs is expected to reach 4 million in 2020, 92 million in 2035, and 240 million in 2050.	Electrification is higher than that in the conventional model in all fields with the gap only expected to increase. For example, the proportion of electric furnace steel in the steel industry is expected to reach 15% in 2020, 33% in 2035, and 46% in 2050. The number of EVs is expected to reach 5 million in 2020, 140 million in 2035, and 350 million in 2050.

** Please refer to the State Information Center's Data Prediction*

End-use energy structure	Simultaneous promotion of using electricity to replace coal and natural gas, the growth of natural gas is rapid, and fuel is slowly replaced.	Substitution is higher than that in the conventional model. Natural gas substitution is slightly lower than in the conventional model.
End-use energy efficiency	Energy efficiency of major industrial products is expected to reach or approach advanced international levels by 2020 and be the international leader by 2035. Energy intensity is expected to decrease by more than 15% from that seen in 2015, reaching the current world average in 2030. End-use energy consumption is expected to decrease more than 15% of those seen in 2015 in 2020, reaching the current world average in 2030. End use energy consumption is expected decrease and growth is expected to gradually slow while natural gas and electricity are used to replace coal and fuel, bringing additional energy efficiency improvements.	The promotion and application of more efficient electricity technologies, such as recycled metal smelting and heat pump technology, are higher than the conventional model. The extent, depth, and speed of energy substitution are higher than the conventional model.
Installed cost of new power generation capacity**	The cost of onshore wind power installed capacity is expected to be CNY 4 400/kW in 2035 and CNY 3 600/kW in 2050. The cost of offshore wind power installed capacity is expected to be CNY 8 800/kW in 2035 and CNY 6 200/kW in 2050. The cost of PV power generation installed capacity is expected to be CNY 2 800/kW in 2035 and CNY 2 300/kW in 2050. The cost of CSP generation installed capacity is expected to be CNY 9 700/kW in 2035 and CNY 4 500/kW in 2050.	The cost of onshore wind power installed capacity is expected to be CNY 3 800/kW in 2035 and CNY 3 000/kW in 2050. The cost of offshore wind power installed capacity is expected to be CNY 7 500/kW in 2035 and CNY 5 000/kW in 2050. The cost of PV power generation installed capacity is expected to be CNY 2 300/kW in 2035 and CNY 1 900/kW in 2050. The cost of CSP generation installed capacity is expected to be CNY 7 600/kW in 2035 and CNY 3 200/kW in 2050.
Carbon emissions cost	Gradually increase from CNY 20/t in 2020 to CNY 200/t in 2050.	Gradually increase from CNY 30/t in 2020 to CNY 300/t in 2050.
Coal power generators flexibility	The minimal output factor of cogeneration units to reach 70% in 2035 and 60% in 2050. The minimal output factor of non-cogeneration units to reach 40% in 2035 and 30% in 2050.	The minimal output factor of cogeneration units to reach 60% in 2035 and 50% in 2050. The minimal output factor of non-cogeneration units to reach peak depths of 30% in 2035 and 20% in 2050.
Cross-regional power transmission flexibility	50% of transmission capacity.	80% of transmission capacity.
Demand response potential	6-8% of peak load demand in 2035 and 10-12% in 2050.	7-9% of peak load demand in 2035 and 15-18% in 2050.
Energy storage installed costs***	CNY 3 000/kW in 2035, and CNY 2 000/kW in 2050.	CNY 2 000/kW in 2035, and CNY 1 000/kW in 2050.

*** Based on the predictions of a number of international authorities such as the International Energy Agency, the International Renewable Energy Agency, and Bloomberg New Energy Finance, the annual cost is expected to exhibit a curve, limiting the study to only show key year values.*

**** Based on the predictions of a number of international authorities such as the International Energy Agency, Bloomberg New Energy Finance, and China Energy Storage Alliance, the annual cost is expected to exhibit a curve, limiting the study to only show key year values.*

ELECTRIFICATION WITH RENEWABLES

Driving the transformation of energy services

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